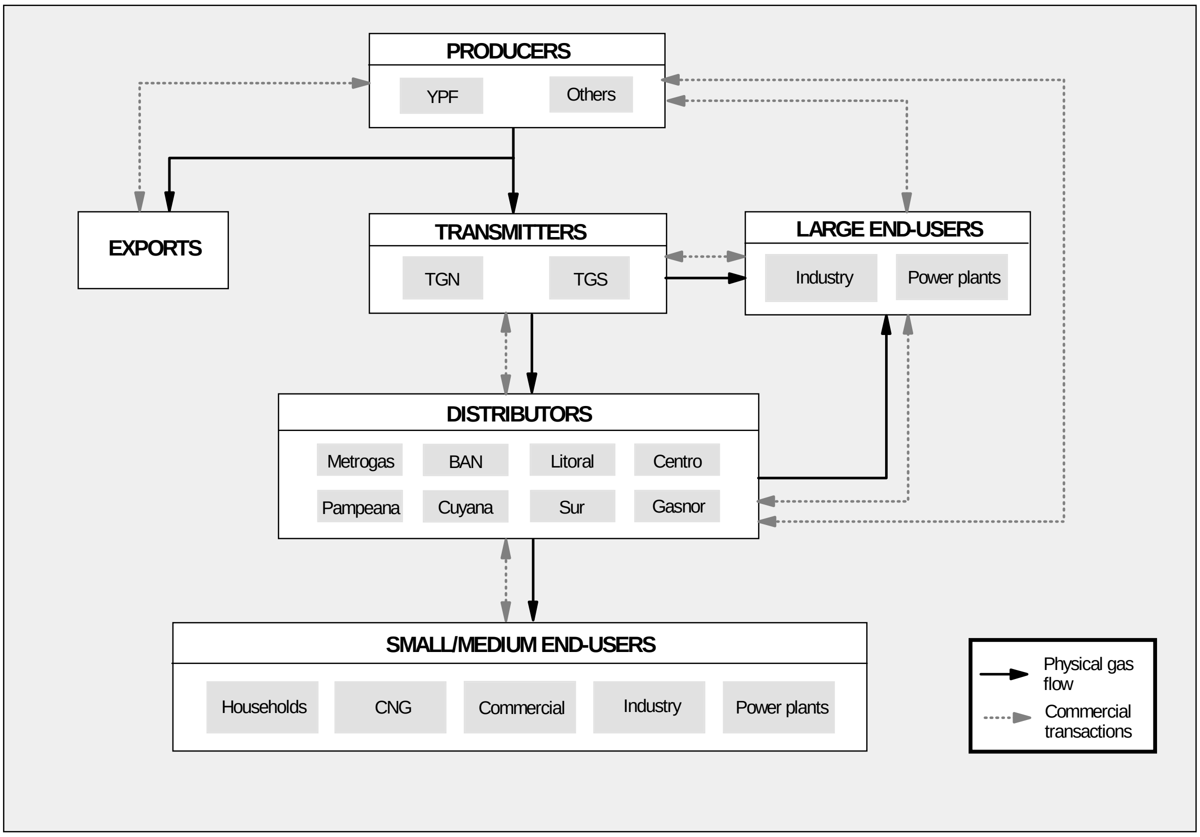
5. IMPACT OF NATURAL GAS SECTOR REFORMS

5.1 Industry Structure

62. The unbundling and privatisation of the gas industry and subsequent mergers and acquisitions have led to considerable diversification in the structure of gas company ownership. Figure 10 summarises the current industry structure, commercial relationships and physical gas flows. Details of physical gas flows from producers through to end-users can be found in Appendix B.

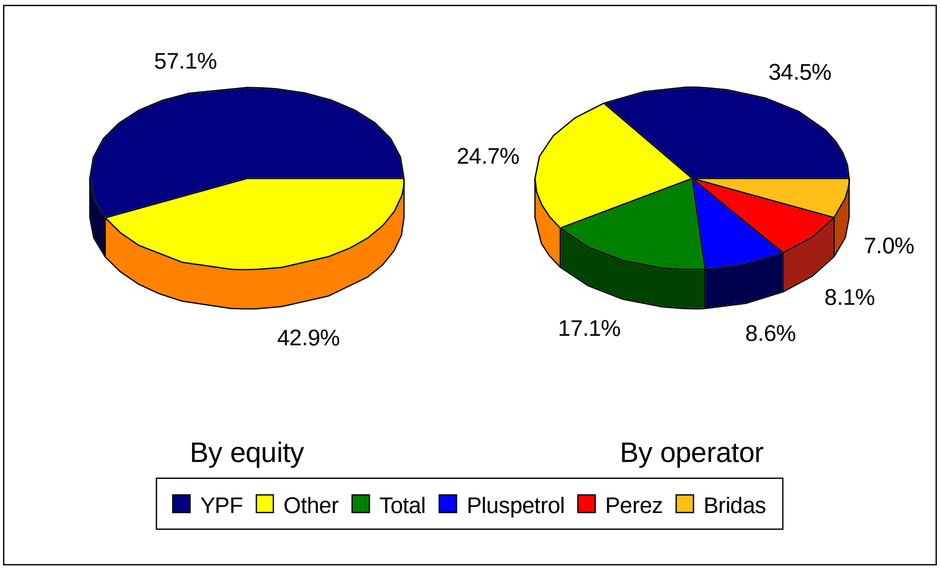
Figure 10
Gas Industry Structure



63. In the upstream, there are around 70-80 companies currently operating in Argentina. YPF remains by far the largest gas producer, controlling 57% of total Argentine output and 58% of supply to the domestic market including imports from Bolivia (YPF is responsible for around two-thirds of imports). YPF's share of domestic gas output has nonetheless declined slightly in recent years, from 62% in 1994. As operator, YPF accounts for a significantly smaller share -- 34% -- of output (see Figure 11), since a number of independent drilling companies that were formerly part of YPF operate fields on YPF's behalf. Total is the second largest producer in Argentina, with 17% of output as operator.

Figure 11

Natural Gas Production in Argentina by Company, 1997



Source: Secretariat of Energy

64. The transmission and distribution companies have diversified ownership, with several North American and European gas companies holding important stakes and performing the task of technical operator. The status of company ownership at end-1996 is shown in Tables 8 and 9.

Table 8

Ownership Structure of Transmission Companies, end-1996 *[to be updated]*

Licensee	*Private investors*			*State holding (%)*	*Province holdings (%)*	*Shared ownership program (%)*
	Company	*%*				
TGN	Gas Invest S.A.		70.00	-	-	5.00
	Tranco Gas Inv.	*22.28*				
	Inversora Catalinas	*22.28*				
	*Nova Gas Int.**	*20.60*				
	Petronas Argentina.	*15.00*				
	Others	*19.84*				
	CMS Gas Argentina Co.		25.00			
TGS	CIESA		70.00	-	-	3.00
	Perez Companc	*25.00*				
	Maipu Inversora	*25.00*				
	EPCA CIESA Inv.	*8.33*				
	*Enron Pi Co Arg**	*25.00*				
	Enron Arg CIESA Hold	*16.67*				
	Citibank		14.00			
	Public		13.00			

* Technical operator.
Source: Enargas Annual Report 1996 (1997).

Table 9

Ownership Structure of Distribution Companies, end-1996 ***[to be updated]***

Licensee	*Private investors*		*State holding (%)*	*Province holdings (%)*	*Shared ownership program (%)*
	Company	*%*			
Metrogas	Gas Argentino S.A., owned by:	70.00	1.76	-	10.00
	*British Gas**	*41.00*			
	Naviera	*25.00*			
	Astra Capsa	*20.00*			
	Arg. Private Dev. Trust	*14.00*			
	Small private investors	18.24			
Gas Natural BAN	Invergas S.A., owned by:	70.00	20.00	-	10.00
	*Gas Natural SDG**	*51.00*			
	Cia Gral de Combust.	*3.00*			
	Manra	*21.00*			
	Discogas Inv.	*25.00*			
Litoral Gas	Tibsa Inversora, owned by	90.00	-	-	10.00
	*Tractabel**	*21.67*			
	Powerfin	*31.33*			
	Inerdrola	*17.00*			
	Others	*30.00*			
Gasnor	Gascart, owned by:	90.00	-	-	10.00
	Jose Cartellone	*40.00*			
	*Gas de Santiago**	*40.00*			
	BFRP	*20.00*			
Centro	Inversora de Gas del Centro,	51.00	-	-	10.00
	owned by: *Sideco Amer. SACIIF*	*75.00*			
	*Italgas**	*25.00*			
	Sideco Americana	29.25			
	Italgas	9.75			
Cuyana	Inersora de Gas Cuyana, owned	51.00	-	30.00	10.00
	by: *Sideco Amer. SACIIF*	*75.00*			
	*Italgas**	*25.00*			
	Sideco Americana	6.75			
	Italgas	2.25			
Camuzzi Gas Pampeana	Sodigas Pampeana, owned by:	70.00	20.00	-	10.00
	*Camuzzi Argentina**	*51.00*			
	Loma Negra	*18.09*			
	Citicorp	*12.50*			
	Pacific Enterprises	*12.50*			
	Others	*5.91*			
Camuzzi Gas del Sur	Sodigas Pampeana, owned by:	90.00	-	-	10.00
	*Camuzzi Argentina**	*51.00*			
	Loma Negra	*18.09*			
	Citicorp	*12.50*			
	Pacific Enterprises	*12.50*			
	Others	*5.91*			

* Technical operator.

Source: Enargas Annual Report 1996 (1997).

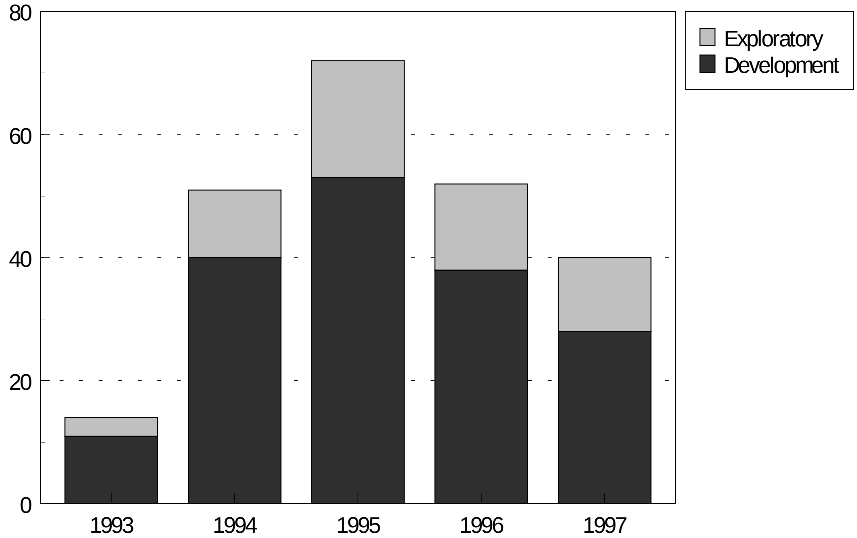
5.2 Upstream Activity

65. The restructuring of the upstream oil and gas sector initially had a positive impact on gas drilling activity and production. Drilling of development and, to a lesser extent, exploratory wells, surged in the early to mid-1990s from a total of 14 in 1993 to 72 in 1995, but has fallen off in the past two years (see Figure 12). Uncertainty over the legislative and fiscal regime (discussed in section 4.2.3), in addition to a levelling off of wellhead gas prices may explain the recent downturn in drilling rates.

Figure 12

Gas Wells Drilled, 1993-1997

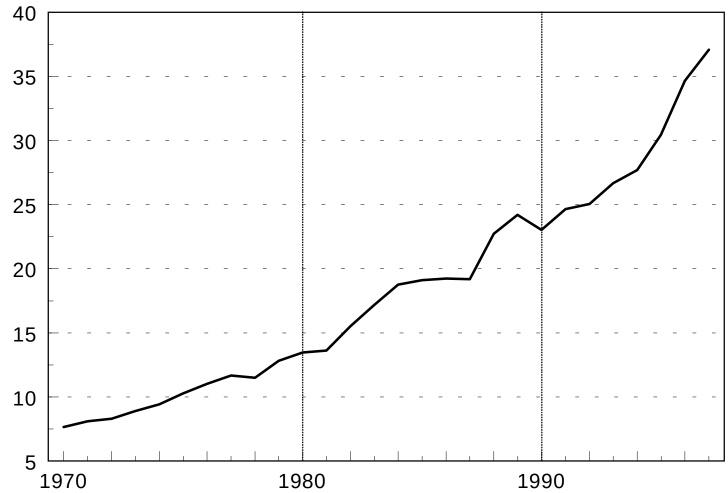
(Number of wells)



Source: Secretariat of Energy

66. The impact of the increase in drilling over the last 4-5 years is reflected in the higher rate of growth of gas production since the early 1990s (see Figure 13). Production, which had levelled off at the end of the 1980s, increased by more than 60% over the period 1990-1997 to just over 37 bcm. The share of associated gas in total gas production has fallen steadily in recent years to less than a third at present.

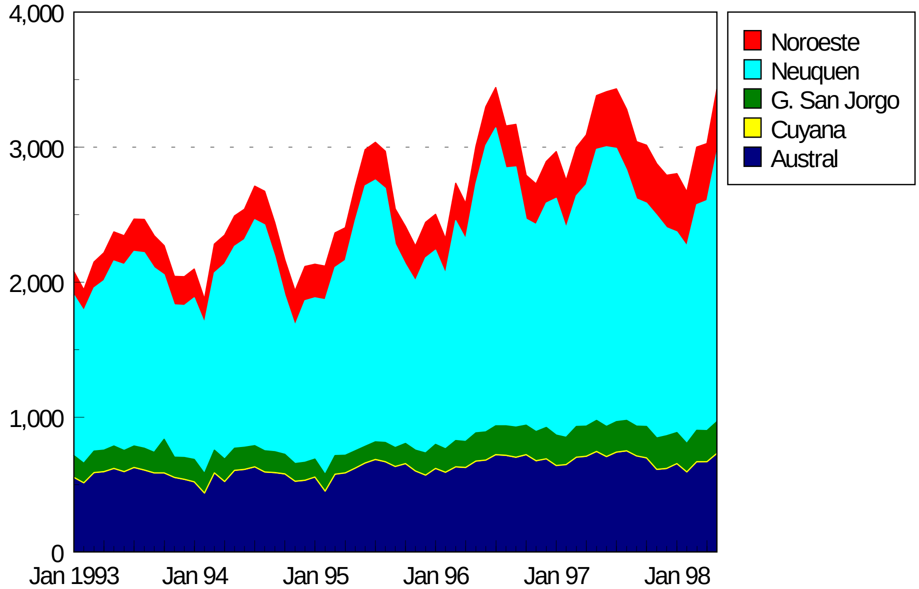
Figure 13
Natural Gas Production, 1970-1997
(Bcm)



Source: Secretariat of Energy

67. Given no underground storage capacity, production is highly demand-driven, retaining a marked seasonality over the past five years (see Figure 14). Production from Neuquen, the largest producing basin, is the most seasonal, acting as the swing supplier to the residential market in the centre of the country.

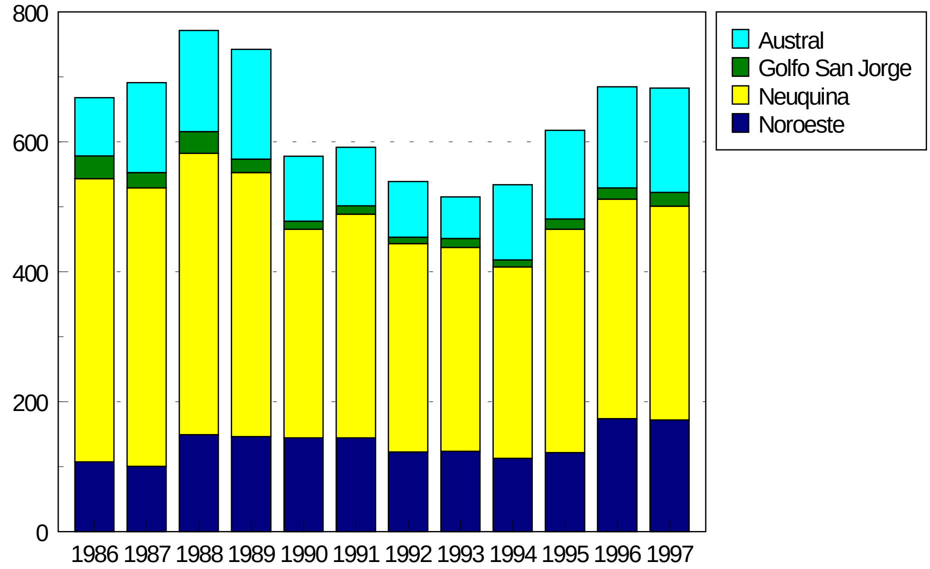
Figure 14
Natural Gas Production by Basin, 1993-May 1998
(Mcm/month)



Source: Secretariat of Energy

68. Proven reserves of natural gas have also increased in recent years, following a steady decline from 1988 through to 1993 (though the large drop in 1990 was mainly caused by a change in the methodology). The biggest increase in reserves since 1993 has been in the Austral and Noroeste basins, though Neuquen still accounts for almost half of total reserves (see Figure 15).

Figure 15
Proven Natural Gas Reserves, End-year 1986-1996
(Bcm)



Note: The sharp fall in reserves in 1990 was due to a change in methodology.
Source: Secretariat of Energy

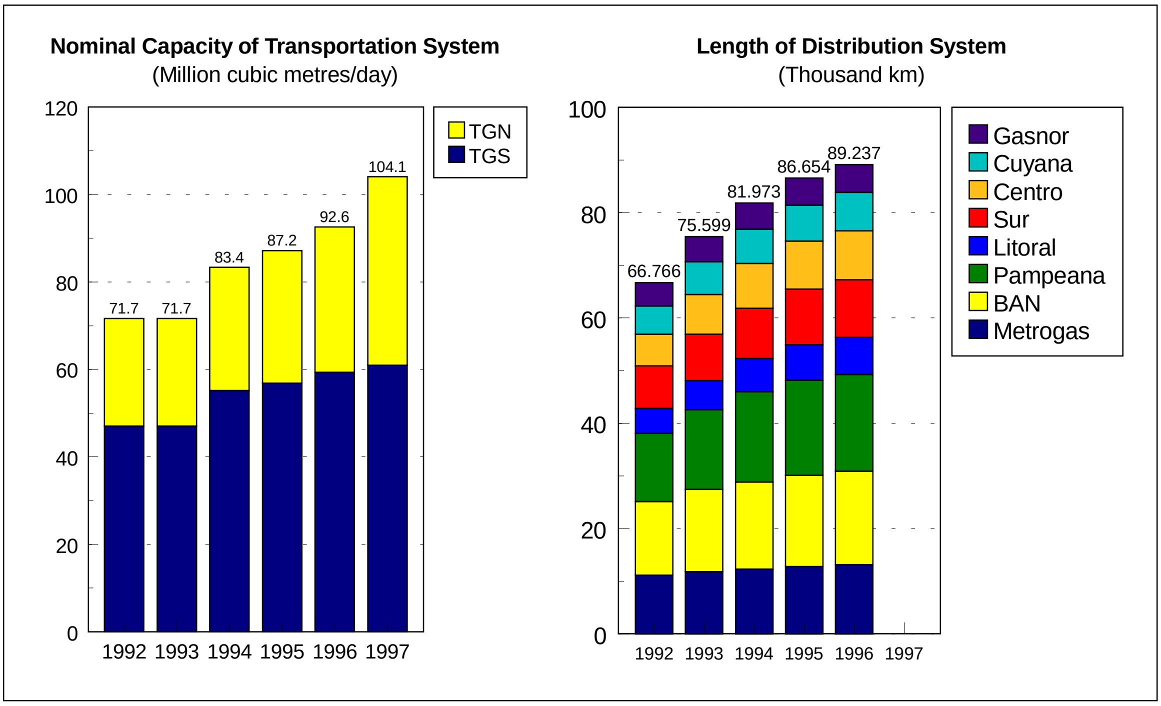
5.3 Downstream Industry Developments

5.3.1 Network expansion and system reliability

69. The gas transmission and distribution systems have expanded significantly since restructuring in response to rising demand, initial bottlenecks and regulatory incentives (the k factor) to invest in capacity extensions. Figure 16 shows the growth in transmission capacity and the size of the distribution networks since 1992.

Figure 16

Expansion of Transmission and Distribution Network, 1992-1997 ***[to be updated]***



Note: Data are end-year**.**
Source: Enargas *Annual Report 1996* (1997); TGN and TGS.

70. There has also been a significant improvement in system control and reliability. Prior to restructuring, reports on pipeline operations were transmitted by telephone while up-to-date information and near-term forecasts of daily loads were limited. Since restructuring, the transmission and distribution companies have greatly improved their monitoring and control systems through the use of information technology. Enargas requires telemonitoring of at least 85% of transmission company deliveries.

71. The expansion of the network and improved reliability were made possible by a sharp increase in investment by the regulated companies: annual investment in transmission increased from US$ 50 million in 1993 to an average US$ 200 million over the period 1994-1996. Of these investments, around US$45 million per year were mandatory for the period 1993-1997. Investment in the distribution networks also increased from US$93 million in 1993 to an average of just over US$200 million in the next three years.

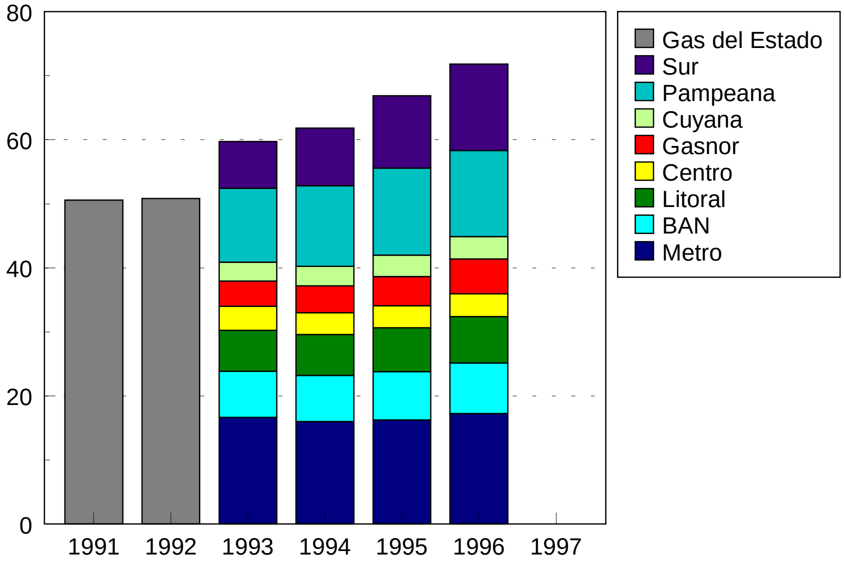
5.3.2 Market trends and patterns

72. Despite the already high level of gas penetration in Argentina, consumption of gas has increased significantly since restructuring. As shown in Figure 17, sales have risen particularly rapidly in the south (in Camuzzi Gas del Sur's licensed distribution area) and northeast (Gasnor's area).

Figure 17

Gas Sales by Distributors to End-Users, 1991-1997 *[to be updated]*

(Mcm/day)



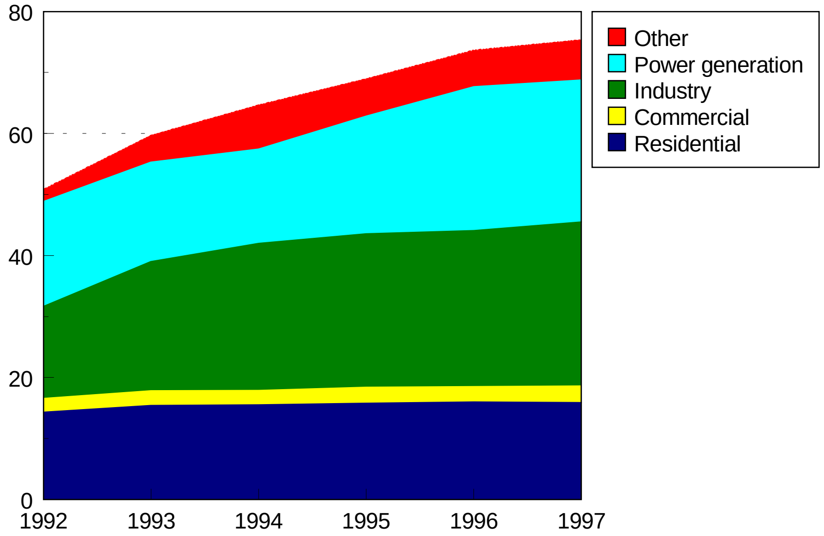
Note: Include direct (bypass) sales to end-users.

Source: Enargas, *Informe Anual 1996* (Annual Report) and *Datos Operativos de las Licenciatarias de Gas* (Monthly Bulletins).

73. Demand has risen in all sectors, though power generation and industry have seen the fastest rates of growth (see Figure 18). Since 1993, power sector demand has risen 43% and industrial demand 27%. Residential demand appears to have stabilised at around 16 bcm/year over the past two to three years.

74. Gas demand in the power sector has been stimulated by restructuring and regulatory reform in that sector. Electricity demand has been stimulated by large reductions in prices, leading to increased investment in generating plant, most of which is gas-fired.

Figure 18
Gas Consumption by Sector
(Mcm/day)



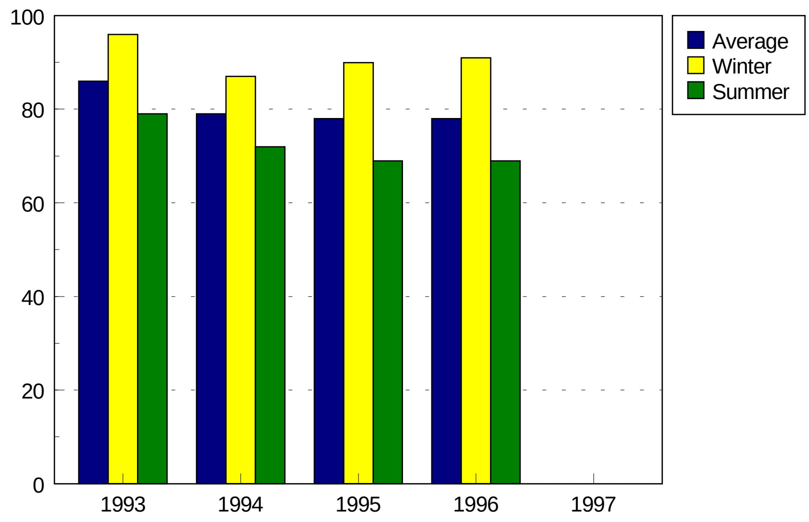
Note: 1992 sectoral shares are estimated.
Source: Enargas, *Informe Anual 1996* (Annual Report) and *Datos Operativos de las Licenciatarias de Gas* (Monthly Bulletins).

75. In 1997, 97% of TGS's nominal capacity and ***[to be added]***% of TGN's capacity were reserved by shippers (mostly distributors) under firm contracts. The total amount of firm capacity reserved by shippers increased from 65.5 mcm/day in 1993 to 82.7 mcm/day in 1996; the share of non-distributors in total firm bookings rose from zero in 1993 to just under 10%. The rate of transmission capacity utilisation has declined since the early 1990s as capacity expansion has outstripped the increase in demand, though average utilisation in the peak winter months is still very high (see Figure 19).

Figure 19

Transmission Capacity Utilisation *[to be updated]*

(System throughput/nominal capacity, %)



Source: Enargas, *Informe Anual 1996* (Annual Report)

76. With the expansion of capacity in the transmission and distribution systems, end-users have significantly reduced their reliance on interruptible contracts (with TGS, TGN and the distributors) in favour of firm contracts. Total sales of gas under interruptible contracts fell sharply in 1994 and 1995. The amount of gas interrupted -- both in nominal terms and as a percentage of total gas sales -- also fell in 1994 but has picked up slightly since (see Table 10). The bulk of interruptible sales are to power stations (CCGTs and open cycle turbines), which are generally the first to be interrupted when winter demand reaches system capacity. Back-up fuels for CCGTs are distillate and LPG; 1% sulphur heavy fuel oil is most commonly the alternative fuel in industry and in single cycle power plants.

Table 10

Interruptible Sales

(Mcm/day)

	1993	*1994*	*1995*	*1996*
Interruptible transmission volume (annual average):				
Distributors	3.4	2.9	1.4	1.0
Others	4.5	3.2	1.8	2.8
Total	7.8	6.1	3.3	3.8
Volume interrupted (June-August)	21.4	2.2	5.1	6.4
Volume interrupted/gas sales to large end-users (June-August)	35.7	3.6	7.9	9.5

Source: Enargas, *Informe Anual* (Annual Reports)

5.3.3 Financial performance

77. The licenced transmission and distribution companies have shown healthy financial performance since restructuring, though net margins and returns on assets have deteriorated generally since 1995. Returns have been highest for the transmission companies -- particularly TGS (see Table 11 and Figure 20).

Table 11

Licensed Transmission and Distribution Company Financial Performance

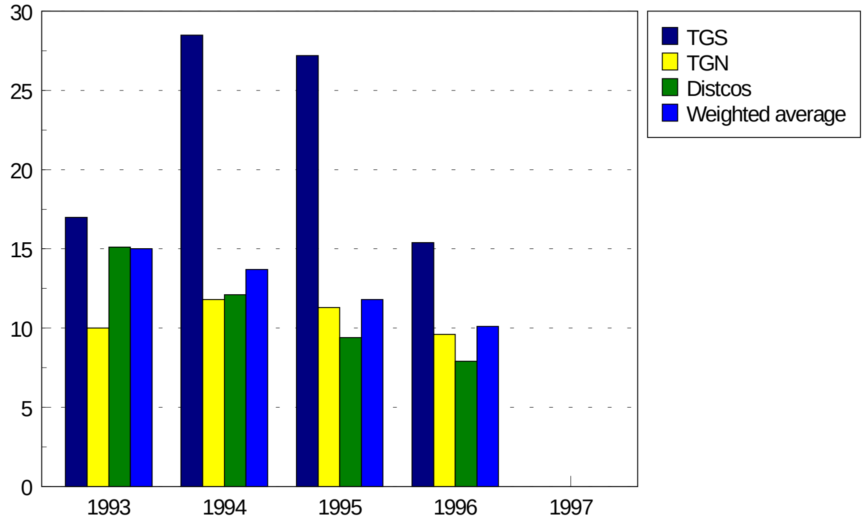
		Transmission Companies			*Distribution Companies*	*Total Licensees*
	Year	*TGS*	*TGN*	*Total*		
Gas sales revenue (US$ mill)	1993	338.4	115.0	453.4	1 967.8	2 421.2
	1994	366.0	136.5	502.5	2 109.3	2611.8
	1995	393.5	155.4	548.9	2 151.0	2699.9
	1996	402.2	163.0	565.2	2 152.8	2718.0
Net margin (US$ mill)	1993	143.6	39.0	182.6	318.9	501.5
	1994	181.3	50.5	231.8	274.0	505.8
	1995	181.0	52.3	233.3	226.9	460.2
	1996	163.8	44.8	208.6	187.9	396.5
Return on assets (%)	1993	17.0	10.0	14.8	15.1	15.0
	1994	18.5	11.8	16.5	12.1	13.7
	1995	17.2	11.3	15.4	9.4	11.8
	1996	15.4	9.6	13.6	7.9	10.1

Source: Enargas, *Informe Anual* (Annual Reports)

Figure 20

Transmission and Distribution Company Return on Assets *[to be updated]*

(%)



Source: Enargas, *Informe Anual* (Annual Reports)

5.4 Contractual Relationships

5.4.1 Purchasing of gas supplies

78. The removal of monopoly rights of supply and the establishment of an open access regime in 1992 have encouraged a number of end-users to negotiate directly supplies of gas with producers rather than buying from the local distributor. Such "bypass" customers come into two categories:

- Those that build a direct pipeline link to the high pressure system of TGS or TGN, contracting with them for transmission services ("physical bypass").

- Those that negotiate use of the local distributor's network in addition to the transmission system ("commercial bypass"). In this case, the customer may negotiate network charges separately with the distributor and the relevant transmission company, or may negotiate a bundled distribution and transmission service with the distributor who, in turn, contracts for transmission on behalf of all its customers

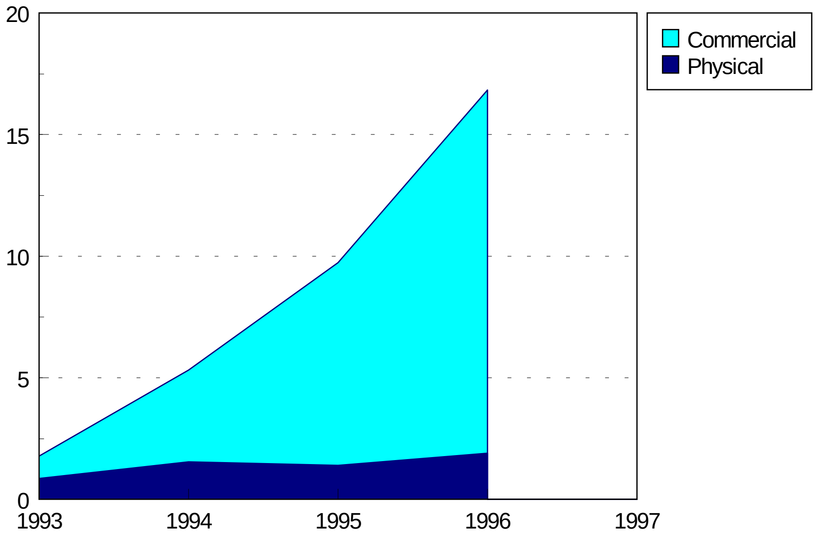
79. The total number of bypass customers and the volumes lifted under these arrangements have increased rapidly in recent years, mainly due to the growth of commercial bypass. In 1996, total bypass sales amounted to almost 17 mcm/day -- equivalent to 23% of total sales (35% excluding sales to the Cerri gas processing plant and off-transmission system sales) -- compared with 1.8 mcm/day (3%) in 1993. Of these sales, physical bypass amounted to 1.9 mcm/day -- equivalent to 2.6% of total sales-- in 1996, up from 0.9 mcm/day (1.4%) in 1993 (see Figure 22). Over 80% of all commercial bypass sales involved a

bundled distribution/transmission service contract.

Figure 21

Direct Purchases of Gas by End-Users *[to be updated]*

(Mcm/day)



Source: Enargas, *Informe Anual* (Annual Reports)

80. The growth of bypass has led to greater diversity in the types of gas supply contracts between producers and buyers (distributors and end-users). Most contracts with distributors are medium term, for five or ten years. The wellhead price in contracts signed in the early 1990s was often fixed. Recently negotiated contracts generally contain escalation formulae, including price indices of competing fuels or internationally-traded crude oil (e.g. West Texas Intermediate) and an inflation index (usually US producer prices). Producers are increasingly pushing for inflation indexation in medium and long term contracts to protect against a possible price collapse due to potential over-supply. With a number of five year contracts now approaching termination, more shorter term contracts (e.g one to three years) are being negotiated.

81. Direct supply contracts with end-users vary according to the type of end-user: power plants are typically supplied under 15 year-contracts, ten year-contracts being the minimum. Escalation terms often include electricity and competing fuel prices. Industrial buyers typically have shorter term contracts of 1-3 years, escalated on competing oil prices (usually gas oil and/or heavy fuel oil). Contracts with distributors and end-users generally contain take-or-pay clauses, with thresholds of 70-90%; swing varies considerably between contracts.

82. The spot market -- informal over-the-counter trades in short term volumes of gas -- has been slow to develop. Although official data is unavailable, industry sources estimate that in early 1998 spot trade

in total amounted to little more than 2% of gas delivered to end-users[1]. Most of this trade was accounted for by distributors and end-users, looking to balance their loads during peak winter months. As yet, there is no regular reporting of spot prices by specialist independent services, as in North America and Europe. There are currently around half-a-dozen licenced gas brokers that handle spot trades on behalf of producers and distributors/end-users.

5.4.2 Contracting for transmission and distribution services

83. The open access regime allows any licenced third party (distributor, producer, trader or end-user) to contract directly with the transmission companies for firm or interruptible service. In practice, however, the distributors, as the original holders of firm capacity prior to restructuring, continue to hold almost all the available firm capacity. At present, more than 95% of all transmission capacity is reserved by the distributors. This has limited the opportunities for producers and end-users to contract directly and explains why most end-users who purchase gas directly from producers opt to negotiate a bundled transmission and distribution service with the local distributor (commercial bypass). Although distributors are obliged to pass on the cost of transmission capacity to commercial bypass customers, they are free to negotiate the cost of using the distribution network. The basis for negotiation is generally the cost to the end-user of building a direct physical pipeline connection to the nearest high pressure system.

84. The 1997 move by Enargas to establish a secondary market for pipeline capacity released by primary holders of reserved capacity was an attempt to promote more efficient use of firm capacity and discourage hoarding by distributors. However, secondary trading in capacity has so far been minimal for a number of reasons, including:

- Lack of storage, which would provide an alternative to holding firm capacity to meet peak winter demand.
- Limited number of sizable producers.
- The ability of distributors under the current regulatory framework to pass on the full cost of firm capacity even if under-utilised.
- The regulatory cap on the price of released capacity, which prevents holders of primary capacity from realising the full economic value of capacity at peak.

[1] In mature competitive markets in North America and Britain, spot trade is much greater than in Argentina, exceeding the volume of gas actually delivered due to reselling.

5.5 Gas Pricing

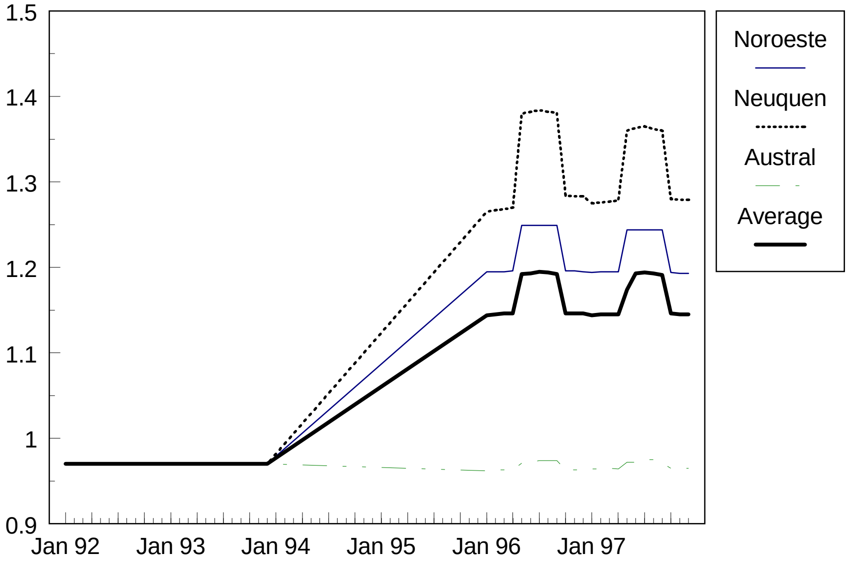
5.5.1 Price trends

85. Average wellhead gas prices have increased since restructuring. The removal of price controls, which had equalised prices across the five producing basins, in 1994 led to a divergence in prices reflecting the netback value of gas delivered to the main consuming area in and around Buenos Aires. On average, effective prices (under current contracts) rose ***[to be added]***% between December 1993 and December 1995. Prices have been stable for the past years. At end-1997, prices varied from US$0.965/Mbtu in the Austral Basin in the South to US$1.279/Mbtu in the Neuquen Basin in the East -- the closest producing area to Buenos Aires (see Figure 22). A degree of seasonality has emerged in Neuquen and Noroeste prices, reflecting the swing role these basins play in meeting winter heating demand. The rise in wellhead prices is reflected in the average prices paid by distributors authorised by Enargas to be passed onto customers (see Figure 23).

Figure 22

Wellhead Gas Prices *[to be updated]*

(US$/Mbtu)

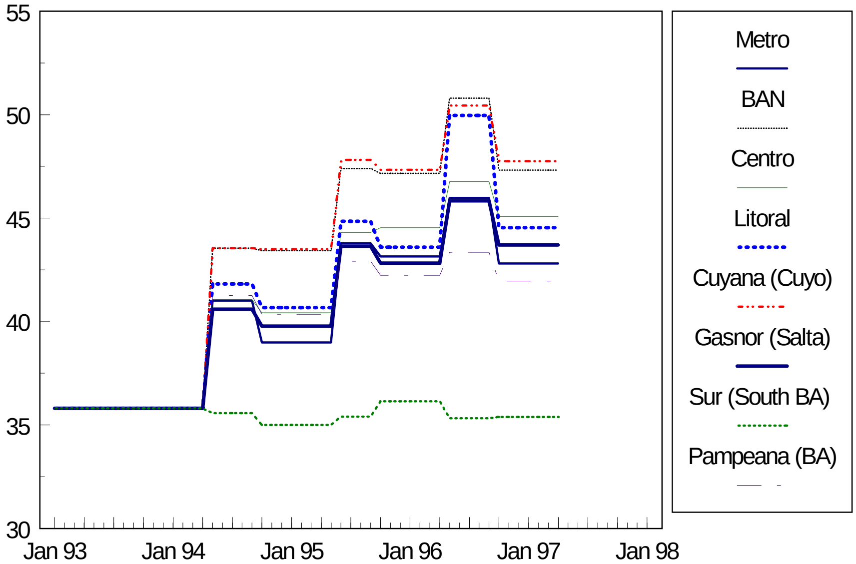


Source: Secretariat of Energy ***[Could the Secretariat please provide data from January 1994 to December 1995]***

Figure 23

Average Gas Acquisition Cost to Distributors Passed onto Customers *[to be updated]*

($/thousand cubic metres)



Source: Enargas, *Informe Anual* (Annual Reports)

86. With transmission tariffs and distribution margins fixed for the period 1993-1997, end-user prices have followed the upward trend in wellhead prices. Prices dropped at the beginning of 1998 with the reduction in transmission tariffs and distribution margins caused by the immediate application of x factors set by Enargas for 1998-2002. Table 12 shows the recent adjustments in tariffs.

87. Under the 1992 Natural Gas Act, distributors are normally allowed to recover the full cost of gas purchases from producers in their final (bundled) sales tariffs to end-users. Recently, however, Enargas has blocked some distributors from passing on all the cost of buying gas on the grounds that the distributors could have negotiated lower prices with producers in different basins where possible. The mechanism set up in 1995 under decree 1020(95) was intended to motivate the distributors to minimise their gas acquisition costs. This mechanism has not been particularly effective, mainly because of the lack of opportunity for effective inter-producer and inter-basin competition. In addition, not all distributors have agreed to participate in the mechanism for fear that they will be penalised if their costs exceed the reference price (determined ex-post by Enargas).

Table 12

Selected End-User Tariffs, 1996-1998 *[to be updated]*

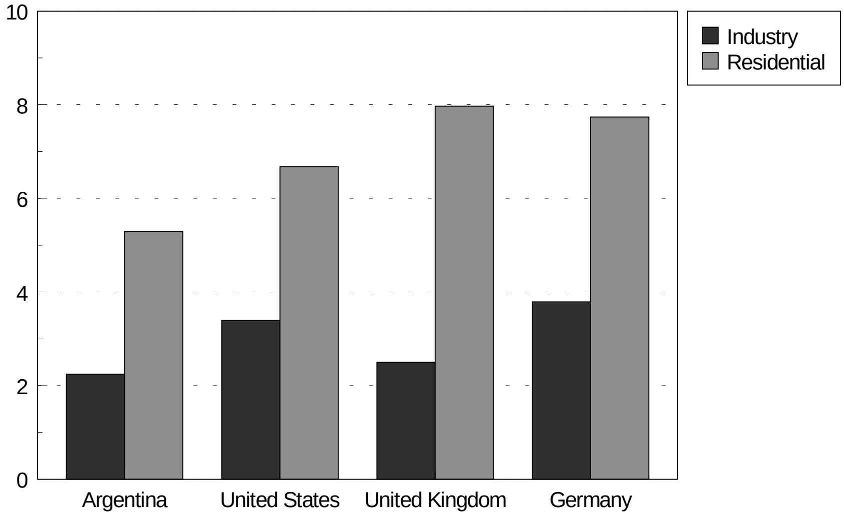
(US$/thousand cubic metres)

Distributor	*Jan 96*	*Jan 97*	*Jan 98*	*Adjustment Jan 98/Jan 97 (%)*		
				Total	*PPI*	*Gas cost*
Residential (R):						
Metrogas	193.0	194.9				
BAN	202.3	204.7				
Centro	191.6	194.3				
Litoral	185.2	188.3				
Cuyana (Cuyo)	185.2	187.7				
Gasnor (Salta)	167.0	169.8				
Sur (Neuquen)	105.3	106.0				
Pampeana (BA)	177.5	179.2				
Commercial/small industry (P):						
Metrogas	153.2	154.5				
BAN	152.3	153.9				
Centro	146.1	148.2				
Litoral	131.9	134.2				
Cuyana (Cuyo)	142.1	143.9				
Gasnor (Salta)	105.9	107.7				
Sur (Neuquen)	99.4	100.0				
Pampeana (BA)	141.6	142.8				
Large industry - interruptible (ID):						
Metrogas	82.5	82.8	76.2			
BAN	86.5	87.2	86.7			
Centro	77.6	78.6	78.3			
Litoral	74.5	75.9	76.5			
Cuyana (Cuyo)	74.0	74.8	74.6			
Gasnor (Salta)	62.1	63.3	63.1			
Sur (Neuquen)	60.6	60.6	64.6			
Pampeana (BA)	72.1	72.2	70.6			

Note: Average tariffs by type of customer, not including taxes. R and P tariffs include fixed charges based on average consumption levels; ID tariff (for interruptible sales off distribution network) is demand charge only.
Source: Enargas, *Informe Anual* (Annual Reports)

88. Despite the increase in prices in the two years following the removal of price controls, average wellhead and pre-tax end-user prices remain significantly below levels prevailing in other major gas-consuming countries in North America and Europe (see Figure 24)

Figure 24
International Comparison of Natural Gas Prices, 1997
($/Mbtu)



Note: Argentina prices are for Metrogas, January 1997. Other prices are national annual averages. Germany prices are for 1996. US residential prices include state sales taxes which vary from 2-6% (the national average is not known).
Source: IEA, *Energy Prices and Taxes*

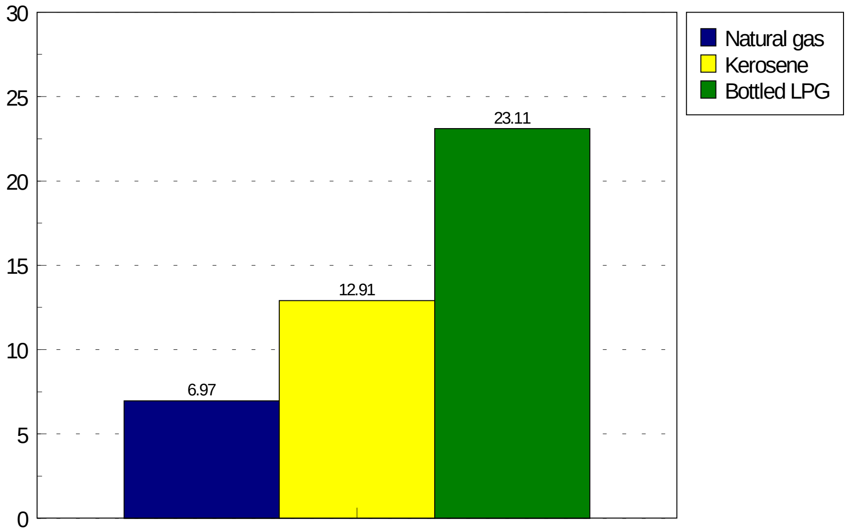
5.5.2 Gas price determination

89. YPF, as the dominant seller of gas in Argentina, effectively sets the price at the wellhead and acts as a price leader for the market as whole. When prices were decontrolled in January 1994, YPF immediately imposed higher prices on the distributors and end-users buying gas directly. YPF has not sought any price increase in the past two years, though it has the market power to do so. This is thought to be due to political pressure on YPF not to raise prices, which would contribute to inflation and hurt the poor, and concerns over possible intervention by the Federal Government to address the lack of competition in the downstream gas and oil sectors. Certainly, prices to all sectors would appear to be considerably below the market value of gas. Figure 25 demonstrates that natural gas is by far the cheapest fuel for heating and cooking in the household sector, which explains the very high penetration of gas. In industry, gas -- even under firm contracts -- is significantly less expensive than heavy fuel oil (see Figure 26). Similarly, in power generation, the fuel cost of electricity generated from gas in existing steam turbine plants, adjusted for differences in thermal efficiency, is considerably lower than for coal and heavy fuel oil, though coal is just competitive with gas in single turbine plant (see Figure 27). Fuel costs are by far the lowest in natural gas-fired combined cycle gas turbines (CCGTs).

Figure 25

Comparative Fuel Costs to Households, August 1997

(US$/Mbtu)

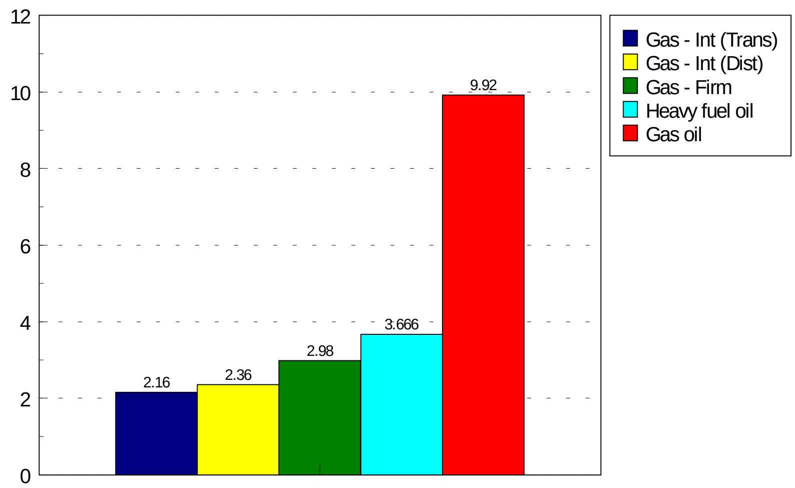


Note: Gas price is for Buenos Aires (Metrogas); kerosene and LPG are national averages. Prices include taxes.
Source: Enargas (gas price); *Gas and Gas Magazine*, April 1998 (Kerosene and LPG prices)

Figure 26

Comparative Fuel Costs to Industry, 1997

(US$/Mbtu)

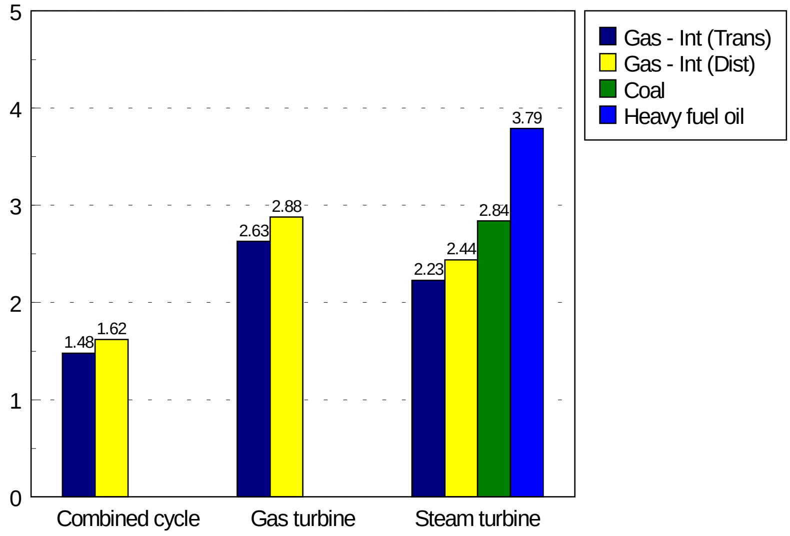


Note: Gas prices are 1st half 1997 for large users in Buenos Aires (BAN) area; heavy and light fuel oil are national averages for 1997. Prices include duties.
Source: Gas prices: Enargas; fuel oil prices: IEA, *Energy Prices and Taxes* (Paris: OECD).

Figure 27

Comparative Fuel Costs in Power Generation, 1997

(US cents/kWh generated)



Note: Gas prices are 1st half 1997 in Buenos Aires (BAN) area; heavy fuel oil and coal are national averages for 1997. Prices include duties.

Source: Gas prices: Enargas; fuel oil and coal prices: IEA, *Energy Prices and Taxes* (Paris: OECD).

6. REGIONAL NATURAL GAS NETWORK INTEGRATION

6.1 Potential Market

90. The Southern Cone countries and their immediate neighbours currently constitute an enormous market with considerable possibilities for expansion of natural gas (see Table 13). Furthermore, energy demand in these countries averages less than a quarter of per capita levels in OECD countries. This percentage and the absolute usage of energy should move steeply upward in the near future given projected economic growth in the region and the particularly close linkage between rates of economic growth and increased energy use at these countries' level of economic development.

Table 13

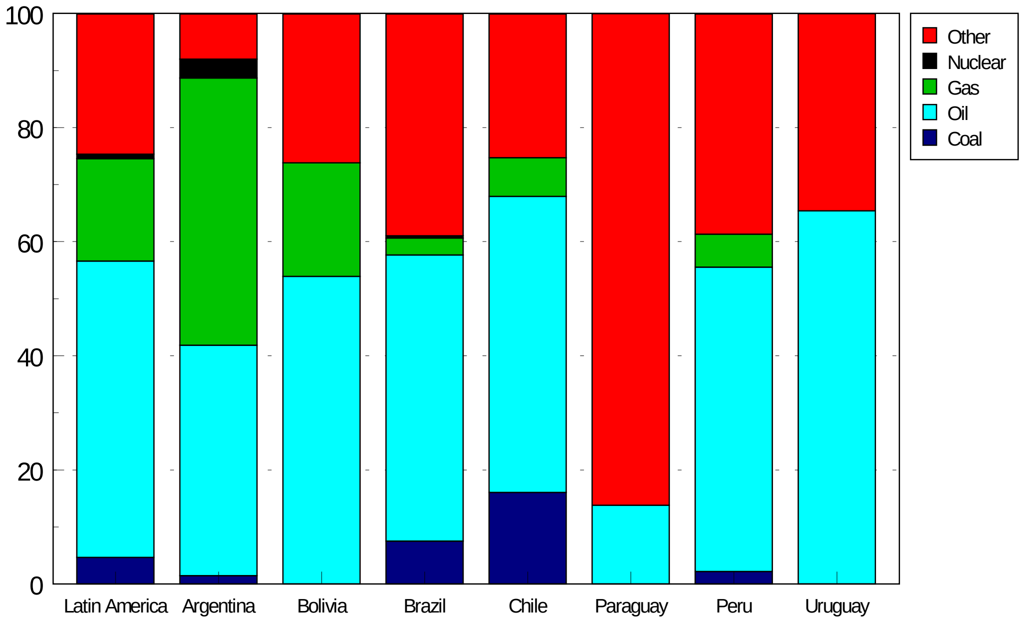
Key Indicators For Selected Latin American Countries, 1996

	Population (million)	*GDP[1]*	*GDP per capita[2]*	*TPES[3] (mtoe)*	*TPES[3] (toe) per capita*
Argentina	*35.22*	*189.38*	*5377*	*58.92*	*1.673*
Bolivia	*7.59*	*5.64*	*744*	*3.63*	*0.479*
Brazil	*161.37*	*557.75*	*3456*	*163.37*	*1.012*
Chile	*14.42*	*46.58*	*3230*	*20.46*	*1.419*
Paraguay	*4.96*	*6.25*	*1261*	*4.29*	*0.865*
Peru	*24.29*	*45.59*	*1877*	*13.93*	*0.574*
Uruguay	*3.20*	*10.40*	*3248*	*2.95*	*0.923*
TOTAL	*251.05*	*861.59*	*3432*	*267.55*	*1.066*

[1] Billion US$ at 1990 prices and exchange rates.
[2] US$ at 1990 prices and exchange rates.
[3] Including combustible renewables and waste.
Source: IEA, *Energy Statistics and Balances of Non-OECD Countries, 1995-1996* (1998, OECD: Paris)

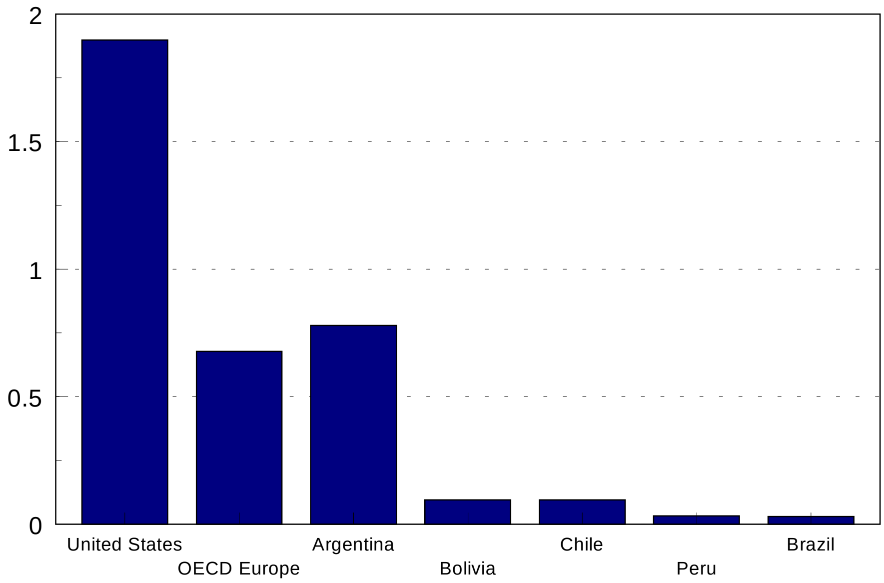
91. Even more notable, with the exception of Argentina, is the limited use of natural gas in the Southern Cone region (see Figures 28 and 29).

Figure 28
Fuel Mix in Primary Energy Demand in Selected Latin American Countries, 1996
(%)



Note: Other includes Hydropower and combustible renewables and waste.
Source: IEA, *Energy Statistics and Balances of Non-OECD Countries, 1995-1996* (1998, OECD: Paris)

Figure 29
Per Capita Natural Gas Consumption in Latin America
(toe/capita)



Source: IEA, *Energy Statistics and Balances of Non-OECD Countries, 1995-1996* (1998, OECD: Paris)

92. Argentina is well placed to benefit from this large potential market given that Southern Cone natural gas production and reserves are predominantly in Argentina (see Table 14). The only competition for the foreseeable future comes from Bolivia, where recent gas discoveries have boosted near term supply potential, and Peru, though plans to develop the large Camisea gas/condensate field have stalled.

Table 14

Natural Gas Production and Reserves in Latin American, 1997

Country	*Production (bcm)*	*Reserves (bcm)*			
		Proven	*Probable*	*Potential*	*Total*
Argentina	37.1	687.9	113.0	NA	NA
Bolivia	6.4	109.6	72.4	25.7	207.7
Brazil	9.2	224.0	87.4	153.2	464.6
Chile	2.7	42.9	80.0	NA	NA
Peru	0.4	198.2	182.6	389.1	769.9
Total	55.8	1 262.6	535.4	NA	NA

Note: NA = not available.
Source: OLADE; SIEE Database.

93. Given the environmental benefits of natural gas, the economies of new combined cycle gas turbines for power generation and the ability of natural gas to often substitute for oil, Argentina's neighbours are very interested in increasing natural gas consumption. The largest market by far is Brazil and, in particular, its southeastern region which is fast becoming economically integrated into the Southern Cone. Total energy consumption in Brazil is expected to increase by 4.5% per annum in the near future with natural gas consumption expanding by as much as 22% per annum, albeit from a very low base. From 1990 to 1996, natural gas consumption increased at an average annual rate of 6.2%. Most of the potential for increased consumption is in the power sector, which is currently almost completely reliant on hydropower. Natural gas has a less than 3% share in Brazil's energy matrix. Brazil would like this share to reach 12% of primary energy supply by 2011. To accomplish this it is absolutely necessary to complement its modest indigenous natural gas production with large quantities of imported natural gas.

94. Demand for natural gas in Chile, the other sizable potential market, is projected to increase by over 15% annually for the next five years. As noted elsewhere in this report, two pipelines providing Argentine natural gas recently were completed and others are under construction or planned. This is understandable given Chile's consistently high economic growth rates, its high annual increases in energy demand, concerns about the environment and limited natural gas reserves and domestic production.

95. Currently neither Paraguay nor Uruguay produce or consume natural gas. However, both would like to begin using it as an energy source.

96. Despite Argentina's abundant natural gas reserves, heavy emphasis on natural gas in its energy mix over the past two decades and clear potential for export, the natural gas infrastructure of its neighbours is very limited or non-existent. Until only a few years ago the only natural gas trade in the Southern Cone was limited to around 2.1-2.4 bcm/year of Bolivian gas delivered under a 20 year contract through a pipeline between Bolivia and Argentina. Even this modest arrangement was politically inspired with the aim of assisting Bolivia economically. For most of the supply period the price paid to Bolivia for the natural gas substantially exceeded the world market price as well as the domestic price in Argentina. Reflecting developments in the rapidly evolving Southern Cone regional natural gas market, some thought is being given to terminate the purchase arrangement with Bolivia and then possibly reversing the flow of the pipeline to allow Argentina access to the Brazil market via the Bolivia-Brazil pipeline now under construction. Recent discoveries in Bolivia may deter or delay this move.

97. The lack of infrastructure limiting natural gas market development outside of Argentina largely stems from earlier nationalistic policies in the region which strongly encouraged energy self-sufficiency, with the exception of bi-national hydro-power projects, and the development of state-owned oil and natural gas monopolies. With the advent of more open, market-oriented policies, in particular encouragement of private sector energy investment and elimination or significant reduction in price controls, interest in expanding use of natural gas in Argentina's neighbours has sharply increased.

98. Similarly, Argentina's production and consumption of natural gas increased significantly in the 1990s following reforms and privatization in its energy sector. However, in the final analysis Argentina has a mature natural gas market. Hence, if its substantial natural gas reserves are to be fully exploited, the real potential growth market lies with its Southern Cone neighbours. Private energy sector investors are well aware of this.

99. Correspondingly, there is political recognition among Mercosur's members and Associate members that if the grouping's economic integration process is to continue to move smoothly and rapidly forward improved infrastructure in and between these countries is required quickly. This is especially true for the energy sector. Of particular importance are natural gas pipelines connecting Bolivia and Argentina with Brazil's industrial heartland.

6.2 Cross-Border Natural Gas Projects

100. Domestic and foreign energy companies have responded rapidly to the opportunities presented by energy sector reforms in the Southern Cone. Many old pipeline proposals have been resurrected and new, often frequently revised, projects are constantly being submitted. Chile and Argentina, the first to implement significant energy sector reforms, were the first to establish new natural gas linkages. However of greater long-term importance are the natural gas connections which would allow the supply of Bolivian and Argentine natural gas to southern Brazil. These would form the basis for an eventual hub of natural gas pipelines throughout the Southern Cone (see Figure 30).

Figure 30

Latin American Natural Gas Pipeline Projects

101. Section 3 outlines natural gas pipeline projects already completed or under construction. However, there are a number of other proposals now underway or under consideration, notably the following:

- A major US$ 2 billion, 3 150 km Bolivia-Brazil pipeline running from Santa Cruz, via Sao Paulo, to near Porto Alegre. This will be the first pipeline providing imported natural gas to the Brazilian market. For the first seven years, 8-9 mcm/day of Bolivian gas will be supplied. This quantity will rise to 28 mcm/d for the following 13 years. Construction is well underway with gas deliveries planned to commence for Sao Paulo in late 1998 and Porto Alegre late the following year.

- A 440 km pipeline from Santa Fe in Argentina to a power plant in Uruguaiana just inside Brazil's border.

- Two lines from Argentina to Chile are planned: Nor Andino, a 3 bcm/year 500 mile line which would run from Northern Argentina to Chile running close to Atacama; and Pacifico, a 1.4 bcm/year 280 mile link from Neuquen to Concepcion.

- A proposed 3 100 Km Mercosur pipeline from Salta in northwestern Argentina to Sao Paulo, in Brazil. A capacity of some 9 bcm/year is projected though there are doubts about the adequacy of reserves to support the US$1.5 billion investment.

- Another 1 bcm/year line from Northern Argentina to supply a power plant at Mato Grasso in southern Brazil has also been proposed.

- A number of possible routes to supply Bolivian gas to Paraguay and possibly southeastern Brazil have been tabled with the authorities though, at the time of writing, construction approval had not yet been obtained.

- A proposed 808 km 6.5 bcm/year pipeline running from the proposed Camisea (Peru) pipeline to Santa Cruz, Bolivia where it would link up with the Bolivia-Brazil pipeline to provide additional gas for the Brazilian market. Considerable doubt has been cast over the project given the decision in mid-1998 by Shell, the majority partner in the consortium, not to proceed with development of the gas/condensate field.

102. Expanded use of natural gas in Argentina's Southern Cone neighbours will provide a number of side benefits to Argentina in addition to simply generating additional foreign exchange from a resource it already possesses in abundance:

- Increased domestic and foreign interest in supplying these growing markets will bring in new investment, managerial and technical skills to develop Argentina's natural gas resources.

- The expanded number and/or heightened competitiveness of natural gas producers in Argentina will provide increased competition to YPF which currently dominates the domestic market.

- Substantial increased natural gas exports should help to ensure that domestic prices in Argentina more accurately reflect world supply and demand conditions.

- The above will serve to facilitate and enhance the effectiveness of Argentina's natural gas regulatory regime.

7. REMAINING CHALLENGES

7.1 Success of Reforms

103. Experience in several countries throughout the world shows that there is no catch-all prescriptive model for the process of regulatory reform and restructuring in the natural gas sector, nor the ultimate regulatory framework once competition has been established. Policy makers and regulators need to take account of specific national circumstances, including the physical characteristics of the pipeline and upstream infrastructure, the ownership structure of the industry and market trends and the institutional framework. Accordingly, Argentina has pursued its own particular approach to gas sector reform within the context of its overall programme of economic restructuring. That approach, nonetheless, has drawn heavily on the experiences and lessons learnt in other countries, notably Canada, the United States and the United Kingdom.

104. In many respects, restructuring and regulatory reform resembles most closely the UK model, where the gas and oil industry was privatised first (though the downstream company, British Gas, was not split into separate transmission and distribution companies as was the case in Argentina). In addition, the regulatory framework in both countries has important features in common:

- Open access to the transmission and distribution network.
- Incentive regulation of transmission and distribution tariffs through an RPI-X formula with pass-through of gas costs and five yearly reviews of efficiency and investment factors.
- An independent, specialist gas sector regulatory authority.

105. The reform process in Argentina has been highly successful. Gas drilling has picked up, investment in the downstream industry has increased and transmission and distribution costs have been reduced. Short-term security, in terms of system reliability and deliverability, has been enhanced. Long term security has also been enhanced through increased drilling and the expansion of international gas trade in the Southern Cone region. Although wellhead prices have risen from the artificially low levels that prevailed prior to deregulation, end-user prices have risen more modestly as a result of improved efficiency and capacity utilisation. Natural gas remains extremely competitive in all end-use sectors and is priced well below the levels prevailing in North America and Europe. Critical success factors behind these achievements include:

- A stable and attractive trading, investment and fiscal environment.
- The removal of gas price controls.
- Diversification of players in the upstream sector through the removal of exclusive rights and the sale of YPF assets and exploration and production rights to competitors.

- The effective separation (unbundling) of the gas transmission business and gas supply/trading, which ensures non-discriminatory third party access to the transmission system and efficient regulation of tariffs.

- Transparency in the non-price terms and conditions of access to the pipeline. This has also been a key factor in preventing discrimination between shippers and ensuring efficient operation of the industry.

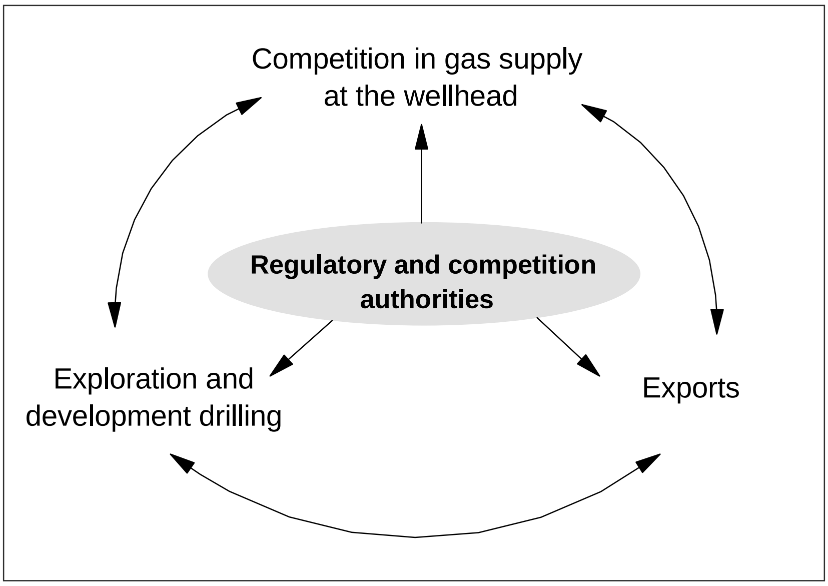
- Explicit rate of return or tariff regulation with incentives to reduce costs.

- Clear definition of regulatory responsibilities with an independent and well-resourced authority.

106. In spite of the impressive progress that has been made in transforming the performance of the natural gas sector, there remain a number of challenges for the government and the regulator. Foremost among these are ***stimulating competition in gas supply***; ***improving the effectiveness and consistency of downstream regulation***; ***stimulating exploration and production***; and ***promoting regional market integration***. These issues are to a large extent inter-related: one way of increasing competition in the Argentine market will be the growth of exports, assuming competitors to YPF account for the bulk of these incremental supplies; new export projects will, in turn, depend partly on the attractiveness of the legal and fiscal regime in the upstream sector for exploration and development and the success of drilling. The Secretariat, Enargas and competition authorities will play a vital role in promoting the long-term development of the domestic and export market (see Figure 31)

Figure 31

Key Factors in Future Development of Argentine Gas market



7.2 Competition in Gas Supply

107. Probably the biggest single disappointment of the reform process launched at the end of the 1980s has been the lack of competition in gas supply -- one of the chief aims of the 1992 Natural Gas Act. Despite divestment of assets and rights prior to privatisation, YPF remains the dominant producer in Argentina and supplier of gas to the domestic market accounting for 58% of total supply, and thus continues to play the role of price leader or setter. It is able to impose prices, pricing formulae and other contractual terms on buyers, though it appears that political considerations deter it from exercising fully this power. YPF is also the dominant player in the domestic oil products market, allowing it to exercise a considerable degree of influence over the prices of the fuels that compete with natural gas in Argentina.

108. The obvious solution to the lack of competition is to reduce substantially YPF's gas (and oil) market share. The Government and the industry recognise this. However, achieving this within the existing legal and institutional framework may be difficult given that YPF is now in private hands. Argentine competition law puts the onus on third parties to prove abuse of dominant position, as is the case in the European Union, rather than outlawing the existence of a dominant position, as in the United States. Any rapid resolution to the problem of lack of competition may, therefore, have to involve the introduction of tougher anti-trust laws, that would have the effect of obliging YPF to dispose of many of its existing gas production concessions and exploration permits. The Government would have to balance the benefits of greater competition against its possible long-term impact on the attractiveness of Argentine industry generally to foreign investors.

109. In the absence of such a move, the Government's only leverage would be through the granting of new exploration permits. Subject to legal considerations, there would seem to be a very strong case for denying YPF involvement in new exploration licensing rounds. Such action would, however, only impact YPF's domestic and export market share after several years. The rate at which YPF's market dominance would decline would depend on the level and success of exploration drilling by competitors, the degree of success in increasing exports and domestic market growth.

110. The ultimate aim -- once effective competition in bulk gas supply is established -- should be to extend competition in gas supply to all end-users. Currently, competition is limited to those consuming more than 10 000 cubic metres/day. Such a move would require at a minimum full separation of the accounting and management of distribution companies' pipeline and gas trading/supply activities (retail unbundling) to prevent discrimination against third parties, encourage access to distribution networks and promote competition[2]. Eventually, a detailed distribution network code setting out contractual and operational obligations, including balancing, would be necessary. Much could be learnt in this regard from

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[2] Complete ownership separation may also be desirable, whereby the distribution companies would not be allowed to trade in gas -- as is already the case for the transmission companies. This would arguably provide water-tight protection against discrimination, but carries higher costs and would certainly entail practical and possibly political difficulties. A compromise solution would be to require separate stock market listing of the two businesses, which would at least reveal more information to the regulator, although this move would not resolve the potential threat of anti-competitive collusion between the trading and pipeline businesses.

the United Kingdom -- the only country as yet with experience of full retail competition[3].

111. The slow development of the spot market for gas and trading in secondary pipeline capacity stems, in large part, from the lack of true competition in supply. Enargas's efforts to stimulate activity in these markets are unlikely to achieve much success until YPF's market share is reduced. Another factor that may contribute to this impasse is the negotiated access regime in the distribution sector: regulation of distribution tariffs, as for transmission tariffs, may encourage more end-users to seek direct purchases of gas (bypass) and broaden the scope for short-term gas trading. In any case, experience in other countries -- notably North America and the United Kingdom -- suggests that a short-term surplus of gas putting downward pressure on prices may be necessary to "kick-start" the establishment and development of short term trading as producers seek alternative channels to long term contracts to dispose of gas supplies.

7.3 Effectiveness and Consistency of Downstream Regulation

112. Enargas has been remarkably successful in developing regulatory competence, given limited experience with independent regulation and competition enforcement in Argentina and the short time (five years) since its creation. The government has provided the body with adequate resources for it to carry out its tasks effectively.

113. The five-year review of transmission and distribution tariffs launched in 1996 and completed in 1997 nonetheless revealed certain shortcomings in Enargas' performance. The regulated transmission and distribution companies have expressed discontent over the manner with which the review was conducted, and especially with the methodology used to determine their x factors. Part of the problem would seem to lie with the Enargas personnel's understandably limited practical experience in tariff review procedures at the time of the review. This should become less of a concern with time. There may be a case for recruiting some permanent staff with appropriate expertise, rather than relying predominantly on external consultants.

114. A specific concern on the part of some of the companies was the lack of a consistent regulatory accounting methodology as the basis for determining the allowed unit revenue (the price cap), given the required rate of return on assets (cost of capital) and projected throughput. At present, the nine regulated companies are not required to employ similar accounting methods and conventions. Critical issues include:

- Valuation of assets for regulatory purposes, taking account of differences between the market value of the companies (as determined by share prices) and accounting cost values.

- Method for revaluing assets over time, from a starting regulatory asset base (for example, using an inflation index or capital replacement cost).

- Treatment of depreciation.

[3] There are nonetheless important differences between Argentina and the United Kingdom, most obviously in terms of the ownership separation of transmission and distribution in the former and the integration of the two activities in the latter.

115. Enargas accepts the need for regulatory accounts and has indicated its intention to establish them in time for the next tariff review for 2003-2008, which will begin in 2001. This should be given priority.

116. Another criticism levied at Enargas by the regulated companies concerns the application of the x (efficiency) factors determined in the recent tariff review in a one-off fashion. The 1992 Natural Gas Act intended the x factors to be applied in a gradual way over the five year period, as in the United Kingdom. Enargas feels that the modest reductions involved (between 4.4% and 6.5% for the full five year period) warranted their immediate application. This move, however, may not have been entirely consistent with the spirit of the 1992 Act and the long-term aim of establishing a stable, consistent and predictable regulatory regime.

117. There may eventually be a case for introducing greater sophistication into the price cap regulatory approach. There is a wealth of literature on the drawbacks of this approach, particularly the danger that it provides regulated utilities with an incentive to under-forecast throughput so as to over-estimate average cost: any increase in throughput over-and-above that assumed in the price cap setting process will automatically lower average costs (because of the large fixed element in total costs) and increase profit. A move to some combination of price and revenue caps, which is gaining acceptance in the United Kingdom[4], may be appropriate given the importance of fixed costs in gas transmission and distribution.

118. Disputes between Enargas and the distribution companies over the full pass-through of gas acquisition costs, which is in principle provided for in the 1992 Natural Gas Act, are ultimately the result of the lack of competition at the wellhead. Enargas is concerned that the distribution companies do not always seek to minimise their gas costs since they are ordinarily fully recovered in final tariffs. In the absence of true competition in supply, the cost-sharing mechanism introduced in 1995 under decree 1020/95, which uses a carrot-and-stick approach, is a sensible attempt to provide the distribution companies with an incentive to minimise total costs. That incentive might be more powerful if the companies were not threatened with financial penalties -- the stick -- if acquisition costs turn out to be higher than the benchmarks set by Enargas, because of the difficulties in setting and justifying benchmark costs. There is, nonetheless, still a danger that the distribution companies will allocate the most expensive gas to their captive customers in the monopoly market (under 10 000 cubic metres/day). Ultimately the most effective mechanism for providing incentives for the companies to seek out the lowest cost supplies for all their customers is full competition at the wellhead through to final consumers (see above).

119. A concern that has been expressed by the industry is the lack of an effective, well-resourced competition authority or other body to act as an arbiter in the event of disputes between the regulator and the regulated companies. There may be a case for giving the existing competition authority a more active role in dealing with disputes or establishing a separate advisory body, possibly along the lines of the Monopolies and Mergers Commission in the United Kingdom or the Competition Authority (Autoritta Garante Competencia) in Italy. These issues -- and the related issue of competition in the oil and gas sector

[4] The UK regulator, Ofgas, introduced a hybrid revenue/price cap in the 1997 BG Transco price review, whereby only 50% of any increase in revenue due to higher than forecast throughput would be retained by Transco.

-- would need to be addressed within the context of a general review of the entire framework of competition law, which is beyond the scope of this review.

7.4 Promoting Exploration and Production

120. A stable legal framework and an attractive tax and royalty regime are vitally important to the long term development of natural gas resources in Argentine, which would in turn support higher exports and promote the development of competition generally in the region. Certainly, there appear to be good prospects for expanding reserves and increasing production in view of the relative immaturity of the Argentine producing gas basins and the fact that most sedimentary basins are unexplored. However, existing legal and fiscal arrangements may no longer be appropriate in view of the restructuring and privatisation of the oil and gas sector and recent weakness of oil prices. In particular, there appears to be a need for greater clarity over upstream regulatory responsibilities and organisation, less onerous conditions in exploration permits and possibly a reduced fiscal burden on production. These reforms can probably only be achieved through an overhaul of oil and gas legislation. Proposals to devolve greater powers over taxation and royalties to provincial authorities will need to take account of industry fears of instability and inconsistency in upstream regulation among provinces.

7.5 Regional Market Integration

110. Although the regional market appears large and receptive to increased natural gas trade, this potential can only be fully realised if compatible investment and regulatory regimes are established in all countries in the region. Furthermore, all governments in the region will need to be transparent and consistent in implementing their legislation and regulatory rulings with an orientation towards eliminating barriers to greater natural gas trade and investment when they occur rather than merely assuming a policing function. The Argentine Government will wish to play an active role in reducing and eliminating barriers to regional trade and investment.

APPENDICES

A. Energy Balance, 1996 (Thousand Tonnes of Oil Equivalent)

SUPPLY AND CONSUMPTION	*Coal*	*Crude oil*	*Petrol. products*	*Gas*	*Nuclear*	*Hydro*	*Combust renew & waste*	*Electric.*	*TOTAL*
Indigen. production	183	42379	-	25688	1944	1977	2690	-	74860
Imports	755	759	1711	1760	-	-	-	315	5299
Exports	-	-16858	-3662	-	-	-	-	-26	-20546
Int marine bunkers	-	-	-570	-	-	-	-	-	-570
Stock changes	-50	-75	2	-	-	-	-	-	-123
TPES	**888**	**26205**	**-2520**	**27447**	**1944**	**1977**	**2690**	**289**	**58920**
Transfers	-	-1306	1440	-	-	-	-	-	134
Statistical differences	-4	215	-1148	-1760	-	-	-	-330	-3028
Electricity plants	-548	-	-977	-8358	-1944	-1977	-135	5999	-7939
Petroleum refineries	-	-24727	23985	-	-	-	-	-	-741
Coal transformation	-81	-	-	-	-	-	-	-	-81
Other transformation	-	-	-	-	-	-	-314	-	-314
Own use	-5	-28	-1059	-3724	-	-	-	-193	-5009
Distribution losses	-8	-	-240	-774	-	-	-	-1097	-2119
TFC	**242**	**358**	**19481**	**12832**	**-**	**-**	**2241**	**4668**	**39823**
INDUSTRY	**242**	**358**	**1230**	**5897**	-	-	**1795**	**1916**	**11438**
Iron & steel	129	-	-	-	-	-	-	-	129
Chemicals,	-	358	657	198	-	-	-	-	1213
of which feedstocks	-	*358*	*657*	*198*	-	-	-	-	*1213*
Non-specified	113	-	573	5699	-	-	1795	1916	10096
TRANSPORT	-	-	**12637**	**906**	-	-	-	**36**	**13579**
Air	-	-	1148	-	-	-	-	-	1148
Road	-	-	11398	906	-	-	-	-	12304
Rail	-	-	-	-	-	-	-	36	36
Internal navigation	-	-	91	-	-	-	-	-	91
OTHER SECTORS	-	-	**4142**	**6028**	-	-	**447**	**2716**	**13333**
Agriculture	-	-	2693	-	-	-	-	40	2733
Commerce	-	-	186	1098	-	-	-	1106	2389
Residential	-	-	1263	4931	-	-	386	1516	8095
Non-specified	-	-	-	-	-	-	61	54	115
NON-ENERGY USE	-	-	**1473**	-	-	-	-	-	**1473**
Electricity generated (GWh)	1520	-	3800	33706	-	-	289	-	69759

Source: IEA, *Energy Statistics and Balances of Non-OECD Countries, 1995-1996* (1998, OECD: Paris)

B. Physical Gas Flows 1997

[To be added]

Source: *Informe Enargas (Annual Report) 1997*

C. TGS/TGN Transmission Tariffs, Effective 1 January 1998

Reception point	Delivery zone	*Firm supply: monthly capacity charge ($/m³/day reserved)*	*Interruptible supply: (US$/1000m³ transported)*	*Demand charge[1]: Gas retained for fuel and losses (% of gas received)*
TGN				
Salta	Salta	0.122935	4.097849	0.91
	Tucuman	0.256116	8.533769	1.97
	Central	0.471252	15.705002	3.37
	Litoral	0.614676	20.489241	4.60
	Aldea Brasilera	0.658731	21.957723	4.90
	Greater B. Aires	0.706879	23.562626	5.20
Neuquen	Neuquen	0.102446	3.585618	0.69
	La Pampa Sur	0.256116	9.732390	2.09
	Cuyana	0.317582	10.582692	2.43
	Central (Sur)	0.327828	10.931010	2.60
	Litoral	0.471252	15.705002	3.83
	Aldea Brasilera	0.519997	17.333247	4.20
	Greater B. Aires	0.573698	19.157440	4.86
TGS				
T. Del Fuego	T. Del Fuego	0.080845	2.694807	0.49
	Sta. Cruz Sur	0.161687	5.389611	0.98
	Chubut Sur	0.404221	13.474031	3.38
	Buenos Aires Sur	0.474960	15.831986	5.60
	Bahia Blanca	0.727598	24.253254	8.40
	La Pampa Norte	0.747809	24.926956	8.60
	Buenos Aires	0.848864	28.295463	10.35
	Greater B. Aires	0.949919	31.663970	11.27
Sta. Cruz	Sta. Cruz Sur	0.080845	2.694807	0.49
	Chubut Sur	0.323377	10.779225	2.89
	Buenos Aires Sur	0.394116	13.137179	5.11
	Bahia Blanca	0.646754	21.558449	7.91
	La Pampa Norte	0.666965	22.232149	8.11
	Buenos Aires	0.768020	25.600657	9.86
	Greater B. Aires	0.869074	28.969164	10.78
Chubut	Chubut Sur	0.080845	2.694807	0.49
	Buenos Aires Sur	0.151585	5.052761	2.71
	Bahia Blanca	0.404223	13.474030	5.51
	La Pampa Norte	0.424434	14.147731	5.71
	Buenos Aires	0.525489	17.516238	7.46
	Greater B. Aires	0.626544	20.884745	8.38
Neuqeun	Neuqeun	0.070739	2.425327	0.49
	Bahia Blanca	0.343588	11.449556	2.80
	La Pampa Norte	0.373904	12.460109	3.15
	Buenos Aires	0.464854	15.491765	3.91
	Greater B. Aires	0.565909	18.897327	4.86

[1] Applies to both firm and interruptible transportation.
Source: Enargas Resolutions 555 and 556.

B/d	Barrels per day.
Bcm	Billion cubic metres.
Cammesa	Compania Administradora del Mercado Mayorista Electrico S.A.; wholesale electricity market operator.
CCGT	Combined cycle gas turbine power station; often gas-fired.
Citygate	Point at which LDC takes delivery of gas; physical interface between transmission and local distribution systems.
Enargas	Ente Nacional Regulador del Gas; gas sector regulator.
Enre	Ente Nacional Regulador de Electricidad; electricity sector regulator.
EU	European Union.
FERC	Federal Energy Regulatory Commission (United States).
GdE	Gas del Estado; former monopoly integrated gas transmission and distribution company.
GDP	Gross domestic product.
GWh	Gigawatt hours (unit of energy)
IEA	International Energy Agency.
Km	Kilometres.
kWh	Kilowatt hour (unit of energy).
LNG	Liquefied natural gas.
Load factor	Average daily system throughput (or consumption) divided by peak daily throughput, expressed as a percentage.
Mb/d	Million barrels (of oil) per day.

Mbtu	Million British Thermal Units; unit of energy.
Mercosur	Southern Cone Common Market, comprising Argentina, Brazil, Paraguay and Uruguay; Bolivia and Chile are Associate members.
Mmcf/d	Million cubic feet per day.
Mcm	Million cubic metres.
Mtoe	Million tonnes of oil equivalent.
MW	Megawatt.
NGLs	Natural gas liquids.
OECD	Organisation for Economic Cooperation and Development.
RPI	Retail price index.
PP	Producer price index
Take-or-pay	A contractual commitment on the part of a buyer to take a minimum volume of gas usually over a 12 month period, usually expressed as a percentage of the annual contract quantity.
Third party access	The right or possibility for a third party to make use of the transportation and related services of a pipeline company for a charge to move gas owned by the third party.
TGN	Transportadora de Gas del Norte
TGS	Transportadora de Gas del Sur
TPES	Total primary energy supply.
YPF	Yacimientos Petroliferos Fiscales.