Industry Report

The Italian Gas Market

Research Department

March 2005

Banca Intesa

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1. Introduction/Overview

1.1 Market Size

The Italian gas market is generally regarded as one of the most dynamic in Europe. In 2003, Italy's gross gas demand amounted to 77.1 Bcm, the third largest amongst European countries. Italian gas demand in the next few years is likely to keep growing at a rate of c.2% per annum, second only to Spain in Europe. Demand is expected to reach c.90 Bcm in 2010 and c.95 Bcm in 2015.

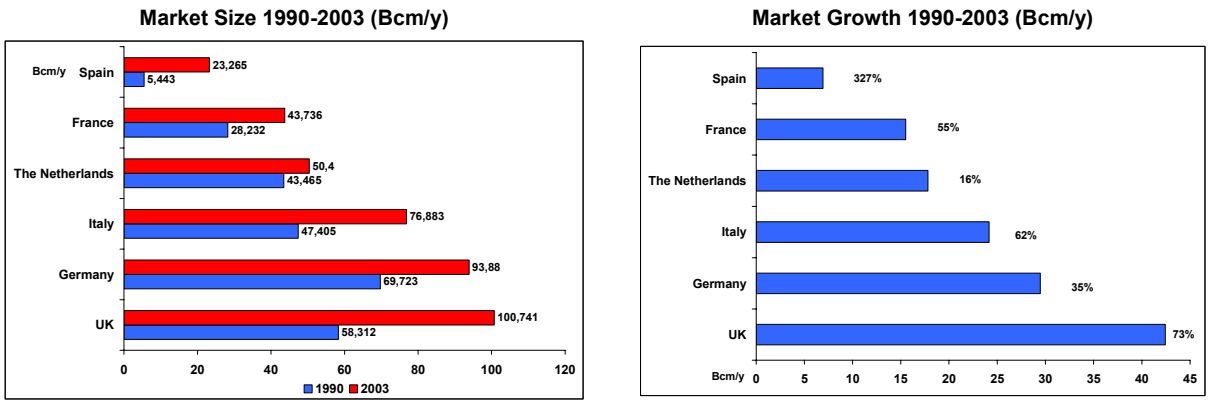
Approximately 18% of the Italian gas market's needs are satisfied by domestic production. The majority of gas supplies come from abroad (62 Bcm in 2003), mainly from Algeria and Russia, but also from the Netherlands, Nigeria and Norway. With forecast production from old and almost depleted fields declining, Italy is obliged to rely on imports in order to satisfy its needs. Currently, the three major import pipelines and one LNG regasification facility have an import capacity of 77 Bcm/y (source: Ministry of Industry). This is adequate for present needs, but further investments are required in order to match the future growth in demand.

The national transportation grid is more than 29,000 km long. It is 95% owned and managed by SNAM Rete Gas, which in turn is 60% owned by ENI. The distribution network is well developed, covering 90% of Italian territory in the North, more than 75% in the Centre and c.45% in the South. Expansion of the distribution network is possible, but at a higher marginal cost. Italy also benefits from a large underground storage system, comprising 10 fields with 15 Bcm of capacity. The broad capacity of Italian infrastructure, its links with Continental Europe and countries fringing the southern Mediterranean, plus its potential for increased demand, give Italy the opportunity to become the gas "hub" for the South of Europe.

1.2 Italian Gas Market in the European context

On the demand side, Italy is the third largest market in Europe, behind the UK and Germany. Gas demand has been growing, from 58 to 71 Bcm in 1987-2001 and to 77.1 Bcm in 2003. Italy is currently the most dynamic country behind Spain in terms of demand growth (9.2% growth between 2002 and 2003), with a CAGR since 1990 of 4.5%, driven by the progressive conversion from oil-fired to CCGT plants.

Fig. 1 - Italy's Position in the European Gas Market

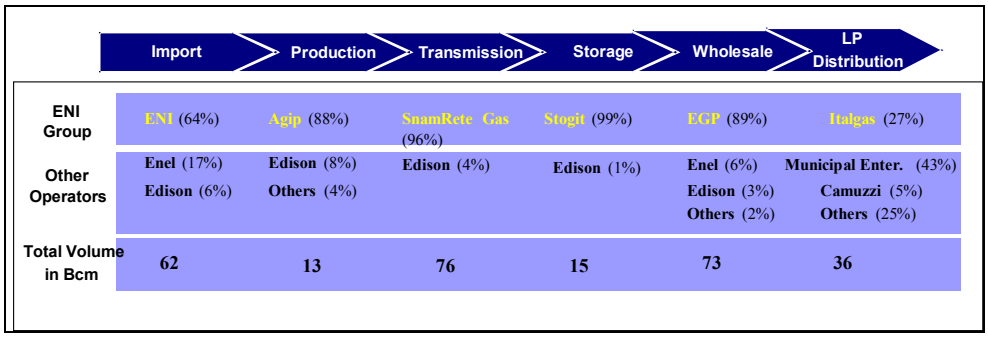


Source: IEA

1.3 Market Structure

In 2003, the Italian gas sector had the following structure:

Fig. 2 - Structure of the Italian Gas Market, 2003



Source: Banca Intesa

It is easy to see from Figure 2 that the large majority of activities are still dominated by ENI, except for low pressure distribution, where ENI accounts for less than 30% of the market. ENI also imports two-thirds of total imports; ENI's upstream division, Agip, has market share of c.90% of total national gas production; Snam Rete Gas (50% owned by ENI), is in charge of gas transmission inside Italy, while Stogit, a 99% ENI-owned subsidiary, is a storage monopoly. Finally, the sales division of ENI Gas and Power, EGP, provides the large majority of wholesale supplies. Consequently, ENI's position has not significantly changed from its de facto monopoly position.

1.4 Comparison with European Prices

Gas prices for final consumers are high, but border prices are in line with the rest of Europe, relative to Italian power prices (which are significantly higher). However, the tax impact on household tariffs is considerable, as taxation accounts for c.40-50% of final tariffs and shows marked regional variations. Small industrial customers are also heavily penalised by taxation compared with their EU peers (35.9 vs. an average of 24.4 euro cents / cm). Price differentials disappear for the largest industrial customers.

Tab. 1 - Average European Prices for Residential Customers, July 2003 (eurocents/cm)

Countries	Average price to residential customers (439 cm/y), net of taxes	Average price to residential customers (439 cm/y), tax included
Austria	45.1	61.1
Belgium	54.4	67.3
Denmark	29.2	69.1
France	54.8	64.4
Germany	54.5	69.9
Ireland	59.8	67.8
Italy	**43.9**	**54.6**
Luxembourg	45.5	48.2
Netherlands	48.9	50.1
Spain	49.6	57.6
Sweden	44.3	78.6
UK	33.8	35.5
Average	**45.5**	**54.0**

Source: Eurostat

Tab. 2 - Average European prices for Industrial Customers, July 2003 (eurocents/cm)

	Average price to industrial customers, tax included (109 959 cm)	Average price to industrial customers, tax included (1 Mcm)
Austria	32.1	30.7
Belgium	28.5	24.7
Denmark	37.1	25.7
Finland	39.8	31.9
France	30.9	24.5
Germany	38.3	36.3
Ireland	26.7	24.2
Italy	**35.9**	**24.6**
Luxembourg	25.5	25.1
Netherlands	Na	Na
Portugal	31.0	23.1
Spain	20.2	20.6
Sweden	25.5	33.9
UK	19.6	17.9
Average	**24.4**	**25.9**

Source: Eurostat

2. Regulatory Framework

2.1 Introduction

Decree 164/00 (the "Letta Decree"), which converted EU Directive 98/30 into Italian law, dramatically changed the regulatory framework of the Italian gas sector. Its main provisions include:

- Import, production and sale are regarded as competitive and liberalised activities. Storage, transmission and distribution, which retain monopolistic characteristics are, as a consequence, more strictly regulated;
- Import, production, transportation, storage, distribution and sale have been unbundled;
- Eligibility thresholds are defined: around 45% of the market was eligible at inception in 2001, but since 2003 all of the gas market has been opened up;
- Antitrust rules on import/production and sale were introduced, in order to foster supply-side competition;
- With regard to the cap on import/production, from 1 January 2002 through to 31 December 2010, no firm is allowed to feed over **75%** of national consumption into the Italian gas grid, on an annual basis. During this period, this threshold will be reduced every year, taking it to 61% of total national consumption by 2010;
- As for the cap on final sales, no firm is allowed to sell more than 50% of final consumption, on a yearly basis, over the same 2002-2010 period.
- The provisions of the Letta Decree have been implemented by several Ministerial Decrees and decisions from the Italian Regulator (AEEG). The main implementation rules are as follows:
- Supply and upstream activities have been liberalised, although further obligations (in addition to the caps) apply in the case of imports from non-EU countries. These obligations relate to industrial capability and the creditworthiness of supply contract subscribers, and, more importantly, to the requirement to provide strategic storage capacity on the Italian market for not less than **10% of yearly contracted imports**;
- Transportation regulation is defined. Gas transportation is controlled by Snam Rete Gas (which was unbundled from Snam and partially (40%) floated on the Italian Stock Exchange). AEEG has defined transportation tariffs, based on entry-exit tariffs that provide a regulated return on investments, with price caps to stimulate efficiency in network operation. Further investments to expand the transport infrastructure (both pipeline and LNG facilities) are encouraged by tariff levels. The framework of rules for access to the Grid (generally known as the **Network Code**) has been defined by the AEEG, as well as balancing mechanisms. Priority of access is given to long-term contracts, while the rest of import capability is assigned on the basis of pro-rata criteria. In future, capacity available on a spot basis will be allocated through market mechanisms;
- Sponsors of new import infrastructure can reserve a minimum of 80% of the facility's capacity for 20 years for its own purposes, subject to obtaining an exemption. Tariffs for reserved capacity may be negotiated between the parties. The remaining 20% is subject to third-party access rules, with tariffs regulated by the AEEG;

- Storage is managed by Stoccaggi Gas Italia (**Stogit**), a subsidiary of Snam, which was unbundled from Snam in order to comply with the provisions of the Letta Decree. Gas storage is complementary to transport activity, but it also has a strategic role, since ownership of stocks allows greater demand/supply modulation. A Storage Code has not yet been drafted. In 2002, the AEEG laid down provisional rules regarding the level and structure of storage tariffs;
- Distribution and sales have been unbundled and fully redefined by AEEG deliberations in 2000, 2001 and 2004. The AEEG has completely revised the tariff mechanisms for distribution, has established minimum tariffs for non-eligible customers, and has provided powerful incentives to make the Italian distribution industry more efficient. Selling to final customers has been a full liberalised activity since 2003, although regulated tariffs continue to be set by the AEEG, in order to best protect those domestic customers who prefer not to switch suppliers.

2.2 Extent of Liberalisation

- Sales liberalisation has been fully in place since 2003 and all final customers are already eligible. However, competition has been developed only marginally in the wholesale market, on account of the segmentation of the customers being supplied.
- **Direct Sales** are made both to industrial and power consumers, connected to the high pressure network. Most of these sales are made by ENI Gas and Power, but its share is expected to decrease. As for sales to power producers, ENI sells c. 13 Bcm. The remainder (over 8 Bcm) is bought directly by Enel and Edison.
- **Secondary Sales**, i.e. sales to local distributors who own and operate medium and low-pressure networks. These distributors work as wholesalers, buying gas from suppliers and reselling it to customers connected to its local grid (residential, commercial, services and small industry). This industry is highly fragmented with more than 350 independent operators. Private operators account for just under 60% of the market (8.7 million customers), while companies run by local public entities account for the remainder.

It is important to note that (almost) all local distributors are supplied by Eni Gas and Power, and that, amongst direct customers, only big power users such as Edison and Enel are, at the moment, partly independent from ENI in terms of supply. Industrial users and small power producers (mainly captive plants) depend on ENI for their gas supply. In fact, in 2003 ENI supplied 89% of the market, directly or through distributors.

A recent investigation by the EU confirms the modest pace of liberalisation. In the retail market, the switch rate is **virtually zero**[1] and previous distributors maintain all of their commercial and residential customers. Competition is slightly more advanced on the wholesale market, where some new operators have been able to import gas from abroad, albeit in only marginal quantities.

The most pronounced competitive effects stem from the rationalisation of the distribution business, with the major players snapping up smaller local

[1] *Recently, however, Enel launched a very aggressive marketing campaign targeting retail customers in several Italian regions.*

distributors. The number of local independent distributors has decreased from over 750 to c.350 in the last four years, and this process is expected to continue in the foreseeable future.

2.3 Tariff regulation: main principles

Liberalisation of the gas sector, like comparable industries such as power, telecoms and railways, comes up against a backbone (the transmission grid) which can only be managed by a monopoly. In the gas sector, this monopoly is apparent at two levels, namely on a national basis for the high-pressure grid and on a local basis for the secondary network (low pressure or distribution grid). Consequently, these monopolistic activities need to be regulated by a Public Authority which sets rules and tariffs for third parties[2] (Third Party Access – TPA).

In addition, storage is an essential element in the gas industry; but while from one standpoint it is an upstream facility – and consequently must be managed as a competitive activity - from another it is a key element for security and strategic reasons and must therefore be regulated in order to avoid market distortions by owners of strategic facilities.

It lies beyond the scope of this study to analyse in detail all the problems relating to TPA mechanisms and pricing structure: in this report we focus on the principles used to set tariffs in order to recover value chain costs, namely supply, transportation, distribution, storage and sales. In addition, we provide a brief description of the tariff structure for each segment of the network[3].

2.3.1 Pricing principles

The main objective of the tariff reform is to separate the cost components at each stage of the gas supply chain, so as to:

1. avoid cross-subsidisation, by preventing integrated companies from charging high prices for activities in natural or structural monopolies (transport, distribution, storage) whilst at the same time lowering their prices for activities where they are in competition with other operators. This would give them an unfair advantage over the competition;
2. enable operators to operate each stage of the gas supply process as a stand-alone service, with an individual price for each service, thereby facilitating access to the gas market.

An in-depth understanding of the new structure of Italy's gas services requires a close look at the tariff system for franchised or domestic customers introduced by AEEG Resolution 237/00, as updated (with material changes) in Resolution 138/03.

The tariff has two components:

1. A fixed portion, set at the same level as the fixed component of the distribution tariff calculated by each distributor.
2. A variable portion or "TV", expressed as:

$$TV = QE + CCI + QT + QS + QL + TD + QVD$$

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[2] *Third parties are companies that do not own the grid (like marketers, wholesalers, traders, other distributors etc.) but want to use it in order to directly deliver/sell gas to customers.*

[3] *For a broad description of the tariff paid by Italian final customers, see "The Structure of gas tariffs in Italy", Banca Intesa, December 2002*

where

- *QE* is the component covering supply costs; the level and the basket to which these costs are indexed are set down in AEEG Resolution 52/99, as later amended by Resolution 195/02 and Resolution 248/04.
- *CCI* is the portion covering costs for wholesale supply to the franchised market, set down in Resolution 138/03 and updated in Resolution 248/04.
- *QT* is the portion covering transmission and dispatching costs; AEEG Resolution 120/01 of 30 May 2001 deals with the structure of the transmission tariff. The review is expected by October 2005.
- *QS* is the portion covering storage costs; the storage tariff was laid down in Resolution 26/02.
- *QL* is the portion covering the cost of using LNG terminals; the structure for this tariff is set out in Resolution 120/01 and updates.
- *TD* is the variable portion of the distribution tariff as set by Resolution 237/00 and 170/04.
- *QVD* is the portion representing sales costs for supplies to the retail market, which is set by Resolution 237/00 and 170/04.

The component recovering supply costs is based on an index which correlates natural gas costs with oil products (fuel oil, diesel) that could be used as substitutes for final uses (i.e. thermal, residential and commercial heating). This index mimics the contractual structure of Gas Supply Agreements under which natural gas is imported into Italy, so fluctuations in international oil prices would be reflected in the tariff paid by final customers.

The tariff components covering segments of the value chain which involve high capital investments and regulated assets (like transport and distribution grids) or strategic assets (like LNG and storage) assets, are *i)* the return on net invested capital (or RAB, Regulatory Asset Base), and *ii)* the allowance of operating costs and depreciation. The RAB is reviewed every four years, on the basis of investments/divestments in the period and depreciation. The sum of the return on RAB, depreciation and the O&M cost generates the maximum annual revenue which companies are allowed to recover. The return is calculated as a real, pre-tax WACC and is different for each regulated activity. The following table shows the regulated return on RAB currently allowed by the AEEG.

Tab. 3 - Regulated return on RAB of each segment

Segment	Regulated return on RAB (real pre-tax)
Transport	7.94%
LNG	9.15%
Storage	8.33%
Distribution	8.8%

Source: AEEG, various resolutions

These tariffs are set in order to promote efficiency; every year, a price-cap adjustment mechanism (called *RPI-X*)is put in place, which allows the recovery of inflation rate less an efficiency component "*X*". Clearly, regulated companies must exceed the benchmark (as represented by the *X-factor*) in order to expand their margins.

However, each gas activity has its own specific characteristics, as detailed in the following chapters.

2.3.2 Supply costs

The cost of acquiring gas from abroad usually includes a fixed capacity component and a variable commodity component. These two parts of the tariff are intended to cover the full cost of imports, namely the cost of the natural gas including transportation costs, and they must cover the fixed investment, operating and maintenance costs for the international gas pipelines carrying the gas from the production centres to Italy. The tariff paid by final customers reflects this traditional tariff framework, via a component called Q_e which covers the pure supply costs, and a fixed component covering international transmission costs and wholesaler margins (known as CCI and recently set by the AEEG: see 2.3.3 below).

In light of these factors, the AEEG set the following formula to update the variable component (and, basically, the entire tariff, given that the other components are reviewed on an annual basis) every three months:

$$\Delta T = \frac{PM_0 * (I_t - I_{t-1}) * PCS}{38.52}$$

where PM_0 is the average gas acquisition cost in the reference month (January 1999), equal to ITL 293.7 per cm; I_t is the index as set out in the next paragraph, and *PCS* is the higher calorific value of the gas purchased, which is 9200 kcal/mc on average.

I_t is the key parameter in the formula. The characteristics of this index are:

- It is reviewed every three months;
- If the change in I_t, on a quarterly basis, exceeds 5%, the tariff is revised; otherwise the tariff remains stable;
- the index is based on a basket of fuels that are substitute products for natural gas and listed on international markets; these are weighted through coefficients that reflect consumption of the fuels in Italy. The formula for this index is:

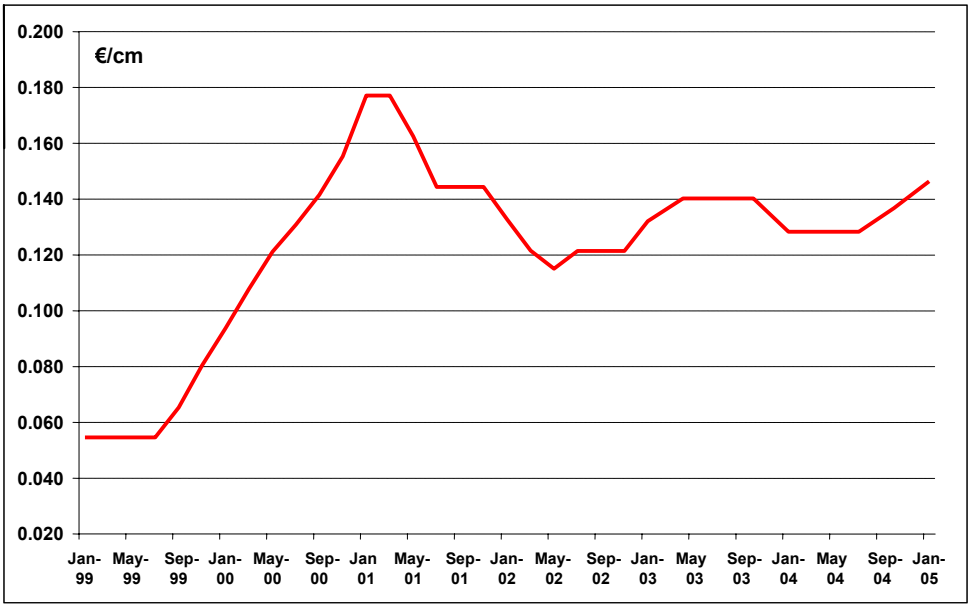
  $$I_t = \alpha * (Gasoil_t / Gasoil_0) + b * (LSHO_t / LSHO_0) + c * (Crude_t / Crude_0)$$

  where the coefficients have the values recently set in Resolution 248/04, as shown in the next table:

A	*0.41*
B	*0.46*
C	*0.13*

- Resolution 248/04 provides a mechanism to protect against excessive fluctuations on the international oil market, with which product prices are correlated. When Brent dated prices exceed the lower and upper limits of $20-35/bbl, a coefficient of 0.75 is applied to the I_t, which limits the effects of oil prices on tariffs for final customers.

Fig. 3 - History of variable component reviews



Source: AEEG, various resolutions

2.3.3 The wholesale component of the tariff

Wholesale (CCI) is the component whose adjustment was most eagerly awaited, since it covers supply costs that are not strictly related to the commodity alone, but to the costs of international transport, wholesale costs and commercial margins. From a purely regulatory point of view, it would be helpful to give separate evidence for each of these components and, where possible (i.e. on international transmission costs), to apply a price cap-style review mechanism, as suggested in the consultation documents. However this, as well as being hard to combine with the practices adopted in international transmission contracts, would have obliged companies to disclose their sales margins. The CCI component is 3.84 euro cents per cubic metre and it is updated on a one-off basis. Through resolution 248/04, the AEEG recently lowered this component by 0.2 eurocents/cm.

2.3.4 The transmission tariff

The AEEG's transmission tariff is an entry-exit tariff, where the entry points correspond to imported and domestic product injection points in the national transmission grid and the exit points correspond to each Italian Region. The tariff comprises a fixed component, a capacity component and a component that varies according to the volume of gas transported:

$$T = (K_e * CP_e) + (K_u * CP_u) + (K_r * CR_r) + CF + E * (CV + CV^P)$$

where

- *K* indicates the capacity granted to the customer at entry point K_e and at exit point K_u for the national transmission grid[4] and K_r for the regional grid respectively;

[4] *Entry points in the national transmission grid are: entry points of import pipelines, entry points of LNG terminals, exit points from storage depots and the main injection points on the national grid. Exit points are: exit points from export pipelines, exit points to storage depots, exit points to the regional transmission grid.*

- *CP* are the national transmission grid charges;
- *CR* is the amount covering regional transmission network costs; the tariff is like a postage stamp, i.e. it remains the same irrespective of distance;
- *CF* is the fixed component, calculated separately by each operator;
- *E* is the gas fed into the grid, in GigaJoules;
- *CV* and CV^p are energy-related charges (where CV^p is the additional charge for new investments).

Operators' charges are calculated according to the following percentages of total revenues:

- 3% of allowed transmission revenues must be covered by the fixed component RT^F;
- 30% of allowed transmission revenues must be covered by the energy component RTE (as must the costs of using regasification tariffs) ;
- 67% of allowed revenues for transmission operations must be covered by the capacity component, divided between national (RT^N) and regional (RT^R) transmission networks by individual operators:
- additional revenues RT^{NP} are guaranteed for new investments via the CV^P component.

Regardless of the cost allowance method, the AEEG's tariff structure offers transporters an opportunity to relax the constraints and secure higher revenues. The energy component allows the volume of gas transported to increase revenues, which:

- provides an incentive to make full use of available capacity;
- provides strong incentives for new investments in the network;
- ensures that transporters' revenues increase in line with demand.

Note that the energy component is calculated in the same way as the variable costs component, within a cost-based tariff structure. Internationally, variable costs are estimated to account for no more than 10% of total transmission costs. A volumes-based component that guarantees 30% of revenues is clearly favourable to transporters, whose revenues from the variable component are higher than the related costs. The transmission transport is due for review by October 2005.

2.3.5 The regasification tariff

Resolution 120/01 also sets tariffs for the use of regasification terminals (the plant at Panigaglia near La Spezia is currently the only one in Italy). Standard principles of calculating an initial RAB (for Panigaglia set at €389m) are applied, setting a maximum annual revenue with a 9.15% return on the investment and adding operating costs and depreciation. Unlike transmission tariffs, companies are free to set the tariff structure they prefer, but the tariffs must be approved by the AEEG and made public. On the basis of this structure, LNG Italia, owner of the Panigaglia site, applies a three-part tariff, comprising a fixed component, a capacity component and an "energy" component (i.e. based on volumes of regasified gas). Sponsors of new terminals will be free to set their preferred tariffs for the capacity they will be allowed to reserve.

Operators' charges are calculated according to the following percentages of total revenues:

- 30% of allowed transmission revenues must be covered by the energy component RTE (as must the costs of using regasification tariffs);
- 70% of allowed revenues for transmission operations must be covered by the capacity component, divided between national *(RT^N)* and regional *(RT^R)* networks by individual operators.

2.3.6 The storage tariff

Resolution 26/02 sets storage tariffs. The cost allowance and price structure is very similar to that of the other tariffs. Specifically:

- the storage tariff guarantees a return on invested capital through the principle of the revalued historical cost, which is already used to set gas distribution tariffs, netted of depreciation and amortisation and public subsidies;
- there are no standard costs applying to all facilities and storage companies[5]; instead, each company can determine these costs, according to the operational and geological characteristics of their infrastructure;
- it assigns to storage companies a weighted average real rate of return of 8.33% before tax;
- it sets a four-year regulatory period and a price-cap mechanism (set at 2.5%) which includes productivity gains;
- it stipulates that tariffs are unique to each storage company and sets a ceiling; however, there is scope for bilateral negotiations to make different arrangements for special, non-discriminatory services to customers;
- lastly, it gives new storage companies freedom to choose their own tariffs, in order to encourage new operators to enter the market.

This is the AEEG's standard tariff method, which naturally also takes account of the specific nature of the service offered. For storage in particular, it specifies that tariffs are to be set irrespective of whether the gas is destined for mineral storage (for the technical upkeep of a storage field), strategic storage (reserves kept to safeguard gas supplies), or modulation (balancing) of the service. It only distinguishes between storage where gas is available and storage where it is not.

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5 *There are two storage companies in Italy at present: Stoccaggi Gas Italia (Stogit), an ENI group company, and Edison*

2.3.7 The distribution tariff pursuant to AEEG resolution 170/04

Distribution tariffs have been set out in Resolution 237/00, which has been strongly opposed by many distributors. After several rulings by Regional Administrative Courts and changes the AEEG has been forced into, in September 2004 resolution 170/04 provided the four-year tariff review, together with material changes designed to take tariff rationalisation a step further. However, given that this reform too has been strongly opposed by local distributors, a new ruling from the Regional Administrative Court is still pending.

a) Tariff structure

The gas distribution tariff system runs on two different lines. The first links maximum permissible revenue to a parameter-based system which calculates the operating and capital costs of distribution using coefficients based on variables of scale, such as grid length and the number of customers served in the area. The second sets the tariff based on the RAB (regulatory asset base), as calculated on the company's accounts. The two methods are used because different types of company work in the sector. These include public limited companies listed on the stock exchange (SpAs) whose accounts are professionally audited, as well as limited companies (Srl) or even partnerships, which do not have accounts that can be used to calculate net invested capital.

This diversity can certainly not be ignored, and the AEEG therefore proposes to retain the current two-track system. Consequently, for small distributors tariffs are set according to a standardised cost methodology using the formulae set out in resolution 237/00 and subsequent additions[6]. However, it proposes a sleight of hand to simplify tariffs to end users, by setting final tariffs on a regional basis. These will be based on the following:

I. A single national tariff structure, with bands made up of fixed and variable components, as in the following table:

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6 *Distribution tariffs for the 2001-05 regulatory period were calculated based on an upper limit on distribution revenues (VRD). This figure was the sum of the distribution operating costs (CGD) and distribution capital costs (CCD). These in turn were based on scale variable parameters considered significant for distribution.*

CGD are calculated using the following formula: $CGD=\alpha_0 NU^{\alpha_1} * Z^{\alpha_2} + cnc*E*(QE+QVI+QT+QS+QL)+PC$, *where* α_0 α_1 α_2 *are coefficients set nationally by the AEEG, NU is the number of users, Z is the ratio of number of users to grid length, cnc is 0.7% and is the component covering distribution leaks, E is the volumes of gas fed into the grid, and (QE+QVI+QT+QS) are the upstream components of the distribution tariff.*

*CCD are calculated on the basis of CCD=g*CID, where g is the coefficient representing the cost of net invested capital, including depreciation. The depreciation rate is set at 2%, and the return on investment at 8.8%. Net invested capital equals the RAB from the company's accounts (for companies whose figures are audited), while it equals* $CID=h_0*NU*Z^{h1}*POP^{h2}*AM+h_3*NU+h_4*E$ *for companies with unaudited accounts.* h_0 h_2 h_3 h_4 *are coefficients set by the AEEG and the other parameters are as above (POP is population, and AM an adjustment coefficient that takes into account the greater costs incurred by distribution companies for works in cities with populations of over 500,000). The cost of capital (using the RAB method) and operating costs for audited companies are calculated from figures drawn from the accounts. Clearly, this method results in the highest revenues and thus in tariffs that vary between areas.*

Furthermore, tariffs are set freely by each individual operator, according to a variable and a fixed charge. The variable charge can be divided into seven consumption bands, where each operator can choose the number and size of the payment, within limits set by the AEEG. The fixed charge may be structured to correspond either to the bands or to different types of meter. Clearly, all this exacerbates differences between tariffs, as the AEEG's own study contained in the consultation document shows.

Tab. 4 - National tariff structure proposed by the AEEG

Consumption bands (GJ per year)		Fixed charge (EUR per client per year)	Variable charge (EUR per GJ)
0	4	30	0.0
4	20	30	2.87
21	200	30	1.58
201	3,000	30	1.14
3,001	8,000	30	0.61
8,001	40,000	30	0.26
More than 40,000		30	0.05

Source: AEEG resolution 170/04

II. This tariff structure may then be adjusted on a regional basis via a specific component, δ_j, that will take into account specific consumption factors in each region. This will be calculated as a ratio between the regional tariff limit (VRDR, derived from the sum of all tariff limits in individual areas for the 2005-2006 thermic year, which, as explained below, is a function of the current tariff limits to be subject to price-capping and the conventional tariff limit (RCTR, which is calculated by applying the single coefficients of the new tariff structure to the volumes and number of users in the region in the 2002-03 thermic year). This regional division should fit well with the present entry-exit structure of the transport tariff on the national grid, where the exit points are regional;

III. An equalising mechanism for the Compensation fund for the electricity sector (CCSE), to be applied to operators in individual regional areas, so that each receives the revenues actually due to it from the area in which it operates[7].

In this way, tariffs to end customers will be the same across each region, which will simplify matters and thus enhance transparency in the sector. This will in turn make it easier for new operators to enter the market. Existing operators, meanwhile, will not suffer financially because of the equalisation mechanism.

The table offers interesting insight into what the relative levels of regional tariffs might be. The north—especially Emilia Romagna, Lombardy, Veneto and Trentino Alto Adige—would have lower payments below the national average, whereas regions in the south—especially Sicily, Calabria, Campania and Lazio—would have higher payments. This reflects “historical” tariff differences, resulting from the number of users and the extent of the grid.

[7] *Note however that a forthcoming AEEG resolution will establish procedures for drawing up the areas for subsequent thermal years. See next section for 2005-06.*

Tab. 5– Average payments nationally, by zone and by region, based on current distribution tariffs

	Single variable payment (EUR cents/cu m)	Single fixed payment (EUR/customer)	Average fixed payment (EUR/customer)	Average variable payment (EUR cents/cu m)
Italy	7.1493	129.3	36.6	5.1270
North	6.0245	133.6	37.8	4.3181
Centre	8.9598	128.4	35.5	6.4829
South	12.5922	115.2	33.7	8.9135
Piedmont	6.0785	140.7	34.8	4.5762
Valle d'Aosta	14.0945	355.6	39.2	12.5421
Lombardy	5.6586	124.5	36.2	4.0176
Trentino Alto Adige	5.8820	160.2	42.2	4.3296
Veneto	5.7819	143.2	42.6	4.0600
Friuli Venezia Giulia	7.1801	141.7	35.6	5.3735
Liguria	11.3827	128.7	33.4	8.4243
Emilia-Romagna	5.4121	134.3	43.6	3.6555
Tuscany	7.2841	128.5	40.4	4.9960
Umbria	8.1508	145.6	35.4	6.1671
Marche	6.7949	125.1	41.8	4.5222
Lazio	12.1261	127.8	30.3	9.2525
Abruzzo	8.3280	126.3	35.9	5.9590
Molise	9.2332	118.0	42.9	5.8743
Campania	12.6461	112.5	31.0	9.1678
Puglia	10.2425	101.6	35.1	6.7063
Basilicata	9.2178	115.1	35.9	6.3481
Calabria	15.3149	139.5	30.0	12.0259
Sicily	17.2570	131.5	36.7	12.4420

Source: AEEG consultation document "Criteri per la determinazione delle tariffe per l'attività di distribuzione di gas naturale per il secondo periodo di regolamentazione" ["Criteria for setting natural gas distribution tariffs for the second regulatory period"], 29 July 2004

b) Transition period until 2005-2006 thermal year: the new limit on revenues and the tariff for 2004-2005

The AEEG believes that such a radical change in the tariff must be introduced gradually. This will be done as follows:

1. The limit on revenues for the year 2004-05 will be calculated on the basis of the current limit (thermal year 2003-04) set for each tariff area, with a price-capping mechanism being applied solely to operating costs and depreciation (i.e. not to ROCE). The productivity growth coefficient is 5%, to be applied on a one-off basis at the start of the second regulatory period. The ROCE component is added to this charge, and is calculated on a one-off basis, by applying a coefficient equal to the percentage difference between the ROCE of the current regulatory period (8.8%) and that set for the second regulatory period (7.5%), weighted using the ROCE component as a percentage of total revenues[8]. This will reduce distribution tariffs by an average of 6.3% nationally.[9]

[8] *For areas where the "simplified regime" is applied, namely smaller distribution companies without audited accounts, this will be 41.84%*

[9] *The distribution tariff accounts for 13.6% of the total final tariff for final residential customers.*

2. The 2004-05 tariffs will be based on this new revenues limit, and will be subject to the new single national tariff structure set out in figure 1. The tariffs will then be calculated for each area (and therefore not yet on a regional basis) applying the coefficient ε_i to the national tariff structure, calculated as the ratio between the single area revenue limit (VRDA) and the conventional revenue described above, but according to area (RCTA). Tariffs will then begin to converge on a single structure. The following year, they will be aggregated on a regional basis using the method described in a) above.
3. An individual regime will be applied for larger companies with audited accounts. This will allow the revenue limit to be calculated taking into account any extra costs, if these are higher than the distribution costs themselves. In this way, the two-track mechanism is retained. Apart from the different ways of calculating the limit, the return on invested capital and the procedure for updating price-caps are the same for all operators, regardless of whether they come under the ordinary or the individual system.

c) Tariff structure for companies with audited revenues. Return on net invested capital and price-cap

For the largest local distributors, tariffs are set using the standard methodology. The method used to calculate the return on net invested capital will still be the Capital Asset Pricing Model and the calculation of real pre-tax WACC, which for distribution will be 7.5%, vs. 8.8% now. Tariffs will be updated via the price-cap mechanism, like all tariff components in the power sector. With regard to the price-cap mechanism, as has already been established for power distribution, the review of gas tariffs will only involve components relating to depreciation and plant operating costs; the return on invested capital will not be affected. Productivity gains will total around 5%. Productivity gains in the previous regulatory period were 3%, but this was applied to all revenues. Given that the proportion relating to depreciation and operating costs is slightly over 58%, the productivity gain factor has remained broadly unchanged over the two regulatory periods. This partial application of the price-cap mechanism should be applied to all the regulated activities in the energy sectors in Italy.

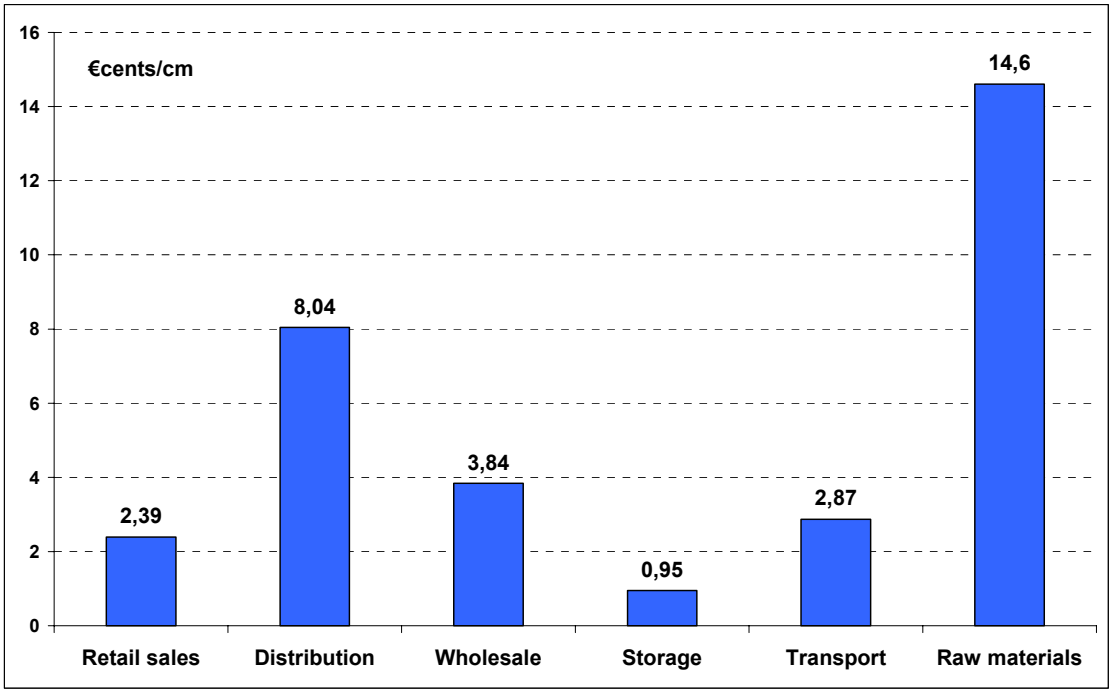
d) Separation of metering activities

Nothing was laid down in resolution 170/04, but the previous consultation document envisaged the separation of metering payments, as has already happened in power distribution. However, partly for safety reasons (the greater experience of operators in running plants), the AEEG has stipulated that operators will continue to run all metering activities, with the exception of meter reading, which will not come under selling activities (which are fully liberalised) in this four-year period. Entrusting meter reading to sales companies is nevertheless an important element in promoting competition. Metering proper will be remunerated by a special payment, calculated using the classic method of return on net invested capital, operating costs and depreciation. For smaller operators, the portion of the revenues limit relating to metering will be calculated as a percentage of total allowed revenues.

2.3.8 National level of tariffs

Before the coming into force of Resolution 170/04, the effects of which are uncertain since the ruling of the Administrative Court is still pending, average national tariff for domestic customers (net of taxes) was 32.7 eurocents/cm, of which c.45% depended on commodity costs. The tariff split by value chain segment is as follows.

Fig. 4 - Average national tariffs for domestic customers, March 2004 (eurocents/cm)



Source: AEEG resolution 138/03

2.4 Regulations Specifically Relating to New Importation Investments

The most important provision established by the EU Directives with respect to the liberalisation of the energy sector is probably **Third Party Access (TPA)** to networks, even where these are owned by other parties. This is basically the only way to guarantee access to markets to new competitors, thereby allowing competition in supply and sales. However, this rule could also be an obstacle to the construction of a new import facility, since sponsors have no economic incentives to build them if the pipeline/LNG is not reserved for them to transport the gas they have contracted.

In order to balance the two key principles of competition and new infrastructure development, the second EU Gas Directive provides guidelines regarding exemptions to the general TPA rules, which every single member state is obliged to observe. Single member States have, however, the discretionary power to define specific rules, provided these are not at variance with the EU guidelines.

Furthermore, pipelines importing gas from non-EU countries are **not subject to EU legislation outside its borders**. Consequently, sponsors of a pipeline are free to allocate capacity and set tariffs as they wish.

With respect to EU and Italian regulations concerning pipelines, the main provisions are as follows:

Under the Italian regulations, as a general principle, Paragraph 17 of Article 1 of Law 239/2004 (so-called "Marzano Decree") states that a derogation from the provisions regarding third party access may apply in the case of gas pipelines between EU member states. The derogation is authorised by a decree issued by the Italian MAP after consulting the Regulator and the other member state involved in the construction of the pipeline. The Marzano Decree set forth the provisions governing the cases in which Parties investing in major new gas infrastructure, such as gas pipelines, LNG terminals, storage facilities and/or expansion of existing infrastructure, may apply for an exemption from the provisions regulating third party access. Such exemptions may be in respect of (i) capacity not exceeding 80% of the new capacity, and (ii) a period of not more than 20 years from the date of commencement of operations. The exemption is issued by the MAP, after consulting the competent authority of the member state involved. This provision also applies to any financial investor or other third party that has helped fund the project by entering into a long-term gas purchase agreement. The remaining capacity (20%) is made available to third parties according to procedures determined by the Regulator, on the basis of efficiency, safety and economic criteria. These criteria do not apply in the event that (i) third party access would prevent the gas operator from fulfilling any public service obligation by which it is bound, or (ii) third party access would result in a significant economic and financial issue for any gas operator (especially with regard to the "take or pay" obligations under any agreement entered into prior to Gas Directive 98/30/EC). The Marzano Decree states that the MAP shall issue a Ministerial Decree governing the principles and procedures regarding the granting of exemptions from third party access. This Decree has yet to be issued.

With regard to the European regulatory framework, considering that the Ministerial Decree must comply with the provisions of Gas Directive 2003/55/EC, the following conditions, provided for in the Directive, must be satisfied in order for a sponsor to obtain an exemption:

- the investment must enhance competition in gas supply and enhance security of supply;
- the level of risk attaching to the investment should be such that the investment would not be made place unless an exemption were granted;
- the infrastructure must be owned by a natural or legal person that is independent, at least in terms of legal status, from the system operators in whose networks the infrastructure will be built;
- charges are to be levied on users of the new infrastructure, and
- the exemption must not be detrimental to competition or the effective functioning of the internal gas market, or the efficient functioning of the regulated system to which the infrastructure is connected.

The national regulatory authority (in Italy, the AEEG following Ministry of Industry guidelines) may, on a case by case basis, decide to grant an exemption. However, EU member states may rule that the regulatory authorities shall only give their opinion to the body in charge of issuing the exemption if so requested. For the sake of providing a complete picture, this opinion is published together with the decision.

The exemption must address the following issues:

- the duration of the exemption;
- the duration of the gas purchase contracts;

- the additional capacity to be built or the expansion of existing capacity;
- the management and allocation of capacity, as long as the allocation does not prevent the implementation of long-term contracts;
- consultation with the other EU member state or regulatory authority involved.

The decision must also be notified, without delay, by the competent authority to the Commission, together with all relevant information relating to the decision. This information should be submitted to the Commission in a complete form, allowing it to come to a well-founded decision. Within two months after receiving the notification, the Commission may request that the regulatory authority or member state involved amend or withdraw the decision to grant the exemption. The two-month period may be extended by one month where additional information is sought by the Commission. If the regulatory authority or member state involved does not comply with the request within a period of four weeks, the Commission may take a final decision on the basis of the information previously submitted.

The provisions set forth in European Directive 2003/55/EC have not been incorporated in detail into Italian legislation; the Marzano Decree states the main principles only with regard to requests to secure an exemption from the Industry Ministry.

The rules defining the use of the infrastructure *per se* are not sufficient to authorize the transport of the gas to Italy; other rules of access have to be defined, namely those governing new capacity access to the national grid. In June 2004, the AEEG published a consultation paper, in which it makes a proposal for defining this important issue. The main provisions of the consultation paper are:

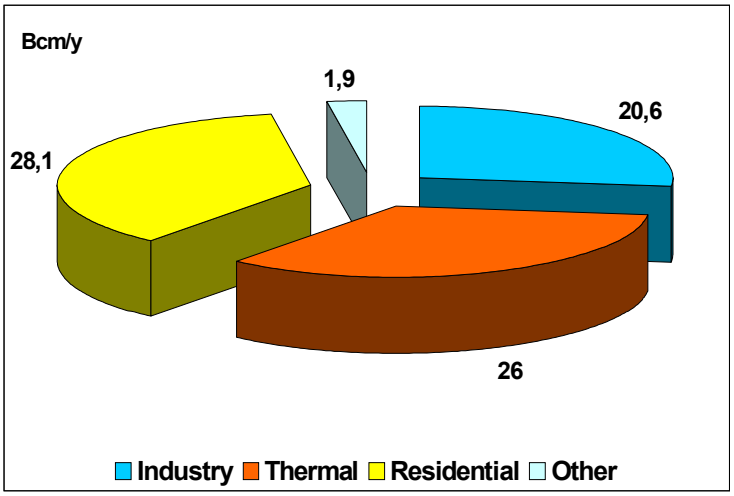
- The request for additional capacity is submitted by the Sponsors of the pipeline to Snam Rete Gas, which starts a procedure known as *open season*. In the following 30 days, all interested parties that may require access to additional capacity at new and existing entry points, make a request to do so, ***provided that*** they *(i)* have already signed supply and international transport contracts and *(ii)* are able to provide a bond guaranteeing payment of the transmission tariffs.
- The AEEG collects all the requests and allocates them on a pro rata basis, leaving 20% of spare capacity for spot requests. The capacity is allocated for 10 years. This procedure should provide IGI Sponsors with access capacity to the grid, to the extent they are both offtakers and shippers. However, their competitors will also have access, via the reservation of 20% of the spare capacity.
- Transmission tariffs *within* Italy will be determined by the AEEG according to the gas flow model that is already used to define entry-exit point charges, based on the investment costs of the new entry point and on gas flows into the Italian grid.

3. Market Analysis – Gas Demand

3.1 Existing demand by sector

Italian gas demand is fairly even split between domestic (36%, namely 28.1 Bcm/y in 2003), industrial (27%, i.e. 20.6 Bcm/y) and thermoelectric consumption (34%, i.e. 26 Bcm/y). Italian demand grew by 9.2% vs. 2002, due to seasonal factors which affected winter residential demand, and to rapid growth in thermal usage, due to the substitution of oil with gas fired power plants. In 2000, natural gas became the most used fuel in Italian electricity generation, surpassing fuel oil consumption for the first time, thanks to 17% growth between 1999 and 2000. Since then, thermal demand has grown by a further 14%.

Fig. 5 - Consumption by Sector- 2003 (Bcm)

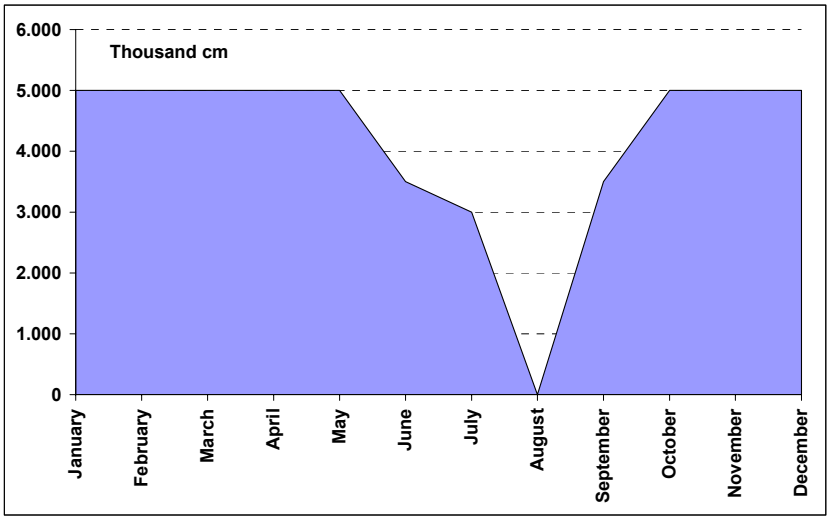


Source: Staffetta Quotidiana

Industrial and residential demand has been relatively flat in recent years; this is due to *i)* the broad completion of the national distribution network, which now covers most of the Italy mainland and Sicily (except for the most isolated mountain regions of the South), whereas a secondary grid is still completely lacking in Sardinia; and *ii)* the sluggish trend in Italian industrial activity in the last few years, compounded by no investments in new large gas-intensive industrial plant.

It is more interesting to gain an understanding of seasonal and geographic differences in typical Italian consumer patterns. To this end, we have developed a typical demand profile for residential and industrial customers.

Fig. 6 - Typical Monthly Profile For An Industrial Customer with Consumption of 50 Mcm/y



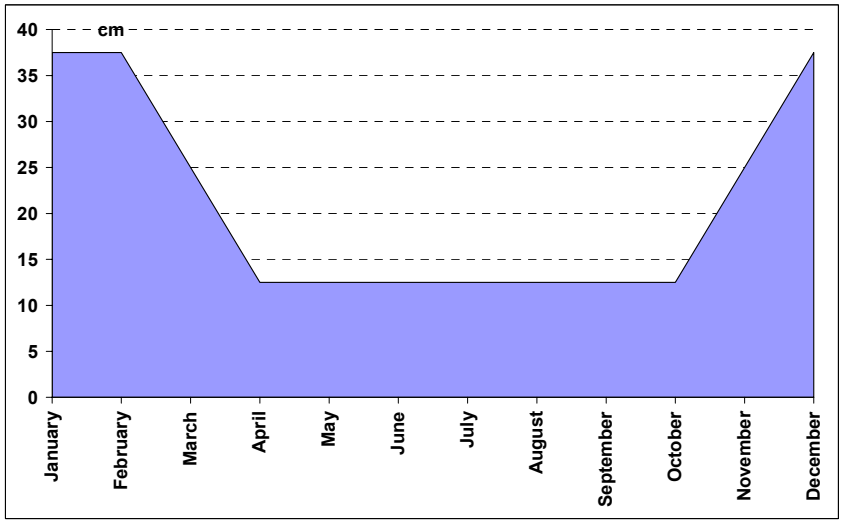
Source: Banca Intesa estimates

Using a typical industrial consumer with 50 Mcm/y of consumption, it is clear that, in general, they are relatively unaffected by seasonal variations. Their annual load factor is relatively high (80%), and the winter proportion of total annual consumption reveals a balanced consumption pattern. Heating is not a significant source of gas consumption, while production cycles have a greater impact.

Industrial gas consumption is steady for eight months of the year. It falls slightly in June, July and September, when production cycles are lower.

As Italian manufacturing industries are typically closed in August, there is likely to be no consumption in that month.

Fig. 7 - Typical Demand Profile For a Residential Customer with 250 cm/y of consumption



Source: Banca Intesa estimates

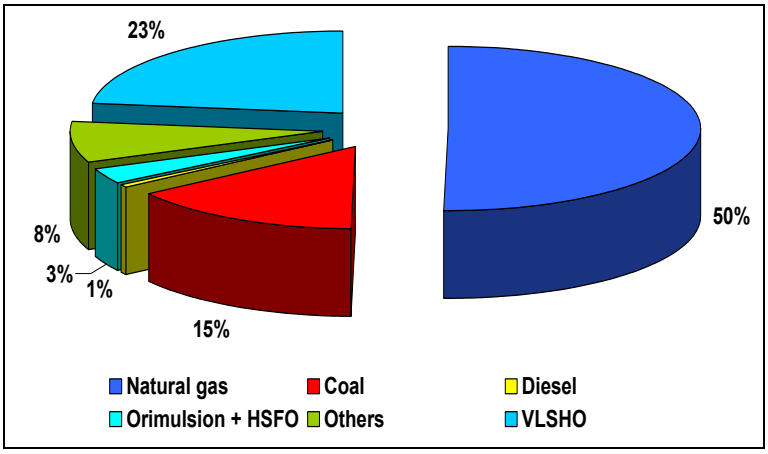
A typical Italian residential customer, with 250 cm/y of annual consumption, has a different demand profile. Residential consumer demand is mainly driven by household heating (water heating needs very little gas). Consequently, demand is **heavily dependent on seasonal weather variations**. 48% of total annual consumption is concentrated in the peak winter months of December, January and February.

Another 20% is consumed in November and March, while the remainder, 32%, is consumed during the other seven months of the year. The annual load factor is only 33%, requiring careful management of storage facilities. Residential consumption patterns are basically the same throughout Italy.

Finally, residential market penetration is high – 90% of the population of the North, 75% in the Centre and 45% of the South are already supplied with gas, which is higher than the European average. The still-to-be-developed areas of the network are concentrated in the South of Italy, Sardinia (currently lacking any natural gas infrastructure) and in isolated mountain areas. According to estimates provided by the AEEG, just 10-15% of unconnected Italian territory could be connected to a gas grid at little cost.

Whereas industrial and domestic demand shows a less dynamic profile, gas utilisation in power generation has grown vigorously in recent years. Gas is already the primary source used in power plants, as shown in figure xxx, having overtaken fuel oil, traditionally the main fuel for power production in Italy. 50% of thermal and about 39% of total power generation (slightly more than 114 TWh), is currently produced by gas combustion. Gas consumption in power generation is still sub-optimal, however. At the moment, gas is mainly burned in old dual or multi-fuel plants, with efficiency rates of only 37%, but the expected start-up of many new CCGT plants should enhance the average efficiency rate.

Fig. 8 - Fuel Share in Thermal Production- 2003 (Bcm)



Source: Staffetta Quotidiana

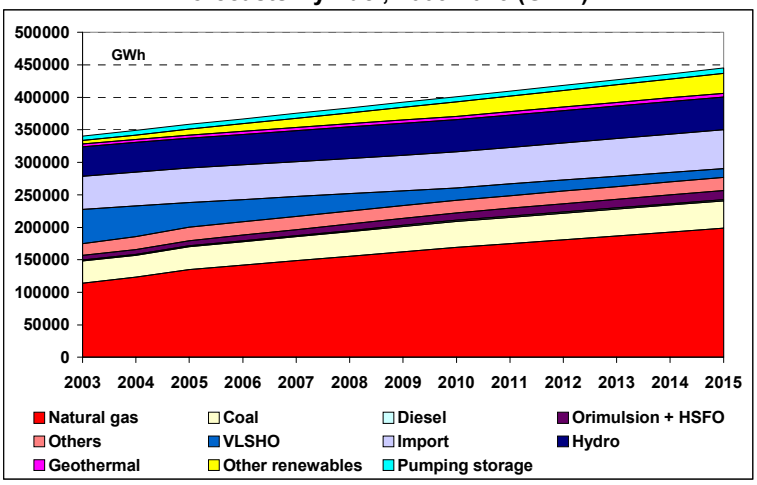
3.2 Demand Forecasts

In its **Base Case** scenario, Banca Intesa forecasts growth in total gas demand from the current 77 Bcm/y to **94.6 Bcm/y** in 2015, implying an annual growth rate of 1.5%.

Growth will be driven mainly by power generation. **Banca Intesa uses its own in-house power model** for power forecasts. The power model suggests that consumption for power generation purposes will increase **from 26 Bcm/y in 2003 to 38.4 Bcm/y in 2015**. Natural gas will be used to produce c.200 TWh in 2015, namely about 50% of total domestic power generation.

This marked increase, common to many European power sectors, is due to the replacement of old and inefficient thermoelectric generating plants (Gensets) with the latest generation high-efficiency Combined Cycle Gas Turbine (CCGT) plants (typically, 400-800 MW). **Both new entrants and incumbents are heavily involved in this process**. Genset renewals involve both the refurbishment of old power plants and greenfield projects.

Fig. 9 - Gross Electricity Production (Included Auxiliary Services And Losses) Forecasts By Fuel, 2003-2015 (GWh)



Source: Banca Intesa

In fact:

1. the former State-owned monopoly Enel is now completing its repowering plan to convert 5,000 MW of its old fuel oil-fired capacity with CCGT plants;
2. The three companies (called "Gencos"), created by Enel in order to comply with the Liberalisation Decree obligation to reduce its capacity by 15,000 MW, were sold to buyers who had to specify their repowering plans for many of the plants as part of their bids. According to these plans, 7,000 MW of old fuel oil power plants will be converted into CCGTs. The three Gencos' repowering processes enjoy the same fast track authorisation procedures as Enel's own repowering scheme.
3. Very low reserve margins, high power prices, the scant efficiency of existing plants and the liberalisation process make Italy one of the most promising electricity markets in Europe. A number of new entrants have

made more than one hundred applications to the Italian Transmission System Operator (GRTN, Gestore Rete Trasmissione Nazionale) for grid connections for new plants, corresponding to c.45 GW of new capacity. Even though total existing installed capacity in Italy is only nominally 75 GW – the Italian Power Grid Operator has stated that only 49 GW is available - it is apparent that only a limited number of requests will be accepted. Furthermore, authorisation and environmental procedures for greenfield projects are often time-consuming and get delayed because of the difficulty in winning local support.

4. **According to our analysis, based on the current status of the authorisation process and local support, only 15-20 greenfield projects will secure the necessary approvals, giving c.12,000 MW of new plant capacity by 2015.**

On the whole, around 24,000 MW of new base load or mid merit capacity is expected to come on line before 2015. A large proportion of this capacity is expected to become operational in 2006-09, considering that one-two years is required to conclude the authorisation procedures and two years is needed for construction.

Apart from power generation, gas demand growth in other sectors is expected to be modest. For residential consumers, demand is expected to grow from the current **26 Bcm/y to about 30 Bcm/y by 2015**, mainly because of the completion of the network in southern Italy. Note that this volume of demand might increase through new customers being connected to the grid, not from incremental use by existing customers. Residential demand in Italy is largely related to household and water heating. Consumption levels and variations depend largely on weather conditions, and no other major changes in consumption are foreseeable. A further increase in residential consumption might arise if the interconnection of Sardinia to import infrastructure from Algeria (c.1.5 Bcm/y) materialises.

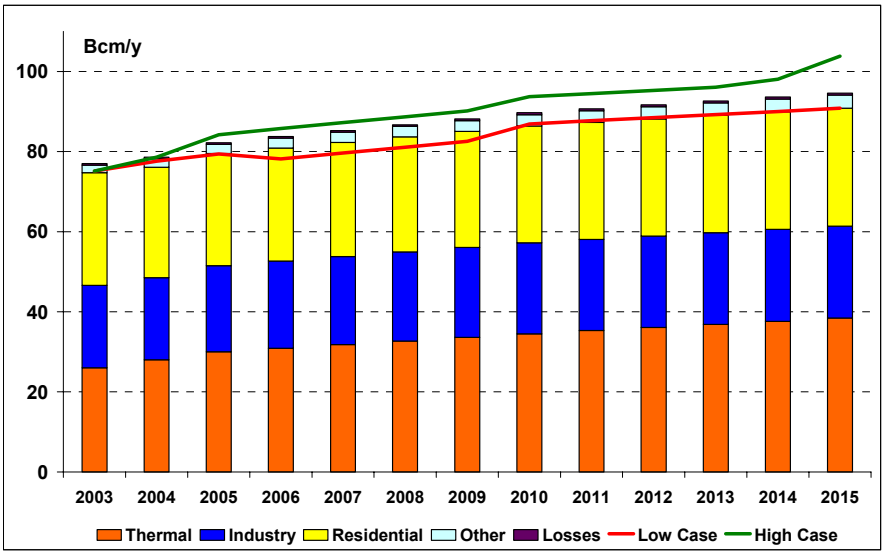
In terms of industrial demand, growth trends are expected to be less dynamic. This sector is, in fact, the most mature of the three, and, according to Banca Intesa information, no further big projects in gas-intensive industries are foreseeable in the short term. Industrial demand is expected to follow the economic cycle and GDP trends, growing quite steadily from the current consumption rate of 21.9 Bcm/y to 23 Bcm/y by 2015.

Banca Intesa has provided two additional scenarios for demand growth, a worst case and a best case, both depending on different trends in gas consumption in the gas sector.

- The **worst-case scenario** takes into account the substitution of some CCGT with other thermal plants fuelled by orimulsion or coal. Two projects of this kind have already been submitted by Enel, one for the conversion to coal of the 2,800 MW oil fuelled Torrevaldaliga Nord plant, (which is fully authorised, but could still encounter strong local opposition), and a second one for the conversion of the 2,400 MW Porto Tolle plant to orimulsion. The possible development of these two plants could “crowd out” some CCGT plants. In that event, we estimate that gas consumption for power generation would only reach 34 Bcm in 2015, while total demand in Italy at that date could increase to **c. 90 Bcm**.
- In our **best-case scenario,** we expect a higher number of CCGT plants, corresponding to a capacity of 20,000 MW, to be in commercial operation before 2015. In that case, gas consumption for power

generation will grow to more than 47 Bcm in 2015, and total Italian gas demand will reach **c. 104 Bcm**.

Fig. 10 - Italian Gas Gross Demand Growth 2003-2015



Source: Banca Intesa

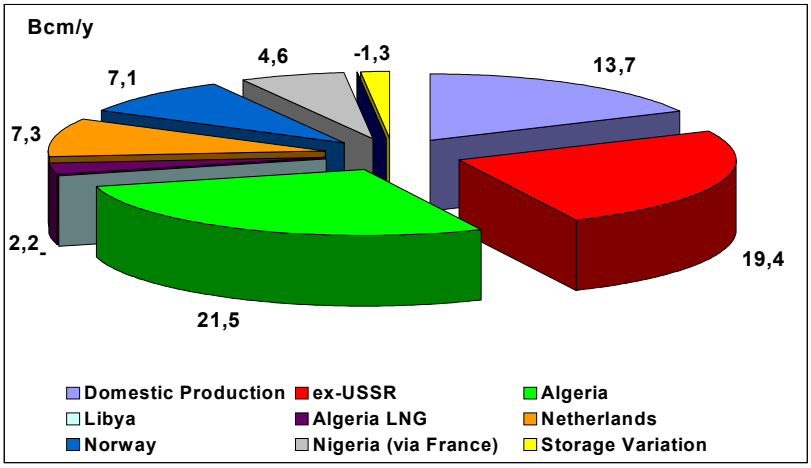
4. Market Analysis – Gas Supply

Having considered the demand-side features of the Italian gas market, in this section we focus on the supply side. The key question is on current and projected supply, both from domestic production and from already contracted imports. In order to do this, we begin in Section 4.1 with an analysis of existing sources of supply. Given the steady or declining trend in domestic production, which currently accounts for c.18% of total supply, an analysis of current and future imports is crucial. Future imports, in particular, depend on the successful construction of new infrastructure, which we examine in Section 4.2. In Section 4.3 we set out our supply forecasts.

4.1. Existing sources

In order to better understand the sources of supply satisfying Italian demand, we can re-classify 2003 imports by geographic region and mode of transport. Figure 9 shows imports by source of supply in 2003. Italian domestic supply was 13.7 Bcm in 2003, i.e. 18% of total supply, but production was down on the 15-16 Bcm/y recorded in 2000-02. It is clear that Algeria and Russia have the lion's share of the market. Algeria exported 23.7 Bcm/y (21.5 Bcm/y by pipeline and 2.2 Bcm/y in LNG, giving it market share of 31%). 19.4 Bcm/y was imported from Russia, giving it market share of 25%. Other import sources are smaller, although it is important to note the presence of Norway which started exporting gas to Italy in 2002.

Fig. 11 – Imports By Country of Origin, 2003 (Bcm/y)



Source: Staffetta Quotidiana

In terms of mode of transport, only **3%** is imported as LNG. Nigerian gas, which should be imported into Italy as LNG, is regasified in France and delivered by pipeline. The Panigaglia LNG regasification terminal has some spare capacity (0.5-1 Bcm/y), which is used mainly for spot imports (in 2003, only for marginal quantities). The existing import contracts are listed in Table 6.

Tab. 6 - List of Already Signed Long-Term Contracts (Bcm/y)

Supplier	Country of origin	Contractor	Entry Point	Pipeline	2003	2005	2015
Gazprom	Russia	ENI	Tarvisio	TAG	24	25	27
Statoil	Norway	ENI	Passo Gries	Transitgas	6	6	6
Gasunie	Netherlands	ENI	Passo Gries	Transitgas	10	10	10
Sonatrach	Algeria	ENI	Mazara del Vallo/Panigaglia	Transmed	21	21	21
Sonatrach	Algeria	ENEL	Mazara del Vallo	Transmed	5	6	6
NOC	Libya	ENI	Gela	GreenStream	0	8	8
Total					**66**	**76**	**78**

Source: Banca Intesa from various sources

The ENI Group has already signed other LT contracts, which will become operational in the coming years. A 6 Bcm/y agreement has been signed with the Norwegian state-owned company Statoil, starting October 2001 and increasing year-by-year until it reaches full contractual quantities in 2006. Another 6 Bcm/y contract has been signed with the Russian company Gazprom, which has been resold to Edison via Promgas (2 Bcm/y) and Enel (4 Bcm/y). Starting in 2005, when the GreenStream pipeline comes on stream, 8 Bcm/y will be imported from Libya, which has been resold to Edison (4 Bcm/y), Energia SpA (2 Bcm/y) and Gaz de France (2 Bcm/y).

Currently, the only other direct importers (except for marginal quantities imported on a spot basis) are Enel and Edison.

- **Enel** has a LT contract with Algeria's Sonatrach to import 4 Bcm/y, with expansion to 6 Bcm/y. 4 Bcm/y has been contracted with Nigerian LNG, but the failure during the 1990s to proceed with the LNG regasification terminal in Monfalcone (near Trieste) due to strong local opposition obliged Enel to enter into a complex swap contract with Gaz de France (and, only marginally, Gasunie). Nigerian LNG is shipped to the GdF terminal in Montoir, where it is regasified. Gaz de France absorbs this gas into its network and provides Enel with 3.5 Bcm/y at the Italian border, 1.5 Bcm/y at Panigaglia (from Algeria) and the remaining 2 Bcm/y at Tarvisio. Gasunie provides 0.3 Bcm/y at Passo Gries, in case of unavailability of Algerian LNG to Panigaglia. This complex agreement generates a surcharge for Enel, which is recovered in the tariffs paid by electricity final customers. Enel has also signed a Binding Agreement to receive 3.2 Bcm/y from its partner BG via Brindisi LNG.
- **Edison** imports 2 Bcm/y from Promgas, the Gazprom/ENI export joint venture, and has agreed to buy 4.8 Bcm/y of LNG from Ras Gas, to be shipped to the proposed LNG regasification terminal (NALT) at Porto Viro.

Consequently, only three players seem to have import capacity into Italy in the coming years. However, Liberalisation Decree 164/00, which set a cap on import capacity share per importer, decreasing from 75% in 2002 to 61% in 2010, has obliged the ENI Group to sell part of its Long-Term contracts to third parties, in a total amount of 13 Bcm/y. Following an investigation by the Italian Antitrust Regulator on competition in the Italian gas market, a further 2.3 Bcm/y for a period of five years will be auctioned this autumn, which might expand availability for small and medium wholesalers. An additional 6

Bcm/y from Russia has been sold to Edison and Enel. A full list of contracts resold to third parties and their duration is shown in Table 7 below.

Tab. 7 - List of Purchase Contracts Resold by ENI to Third Parties

Importer	Ownership	Imported from...	Quantity imported Bcm/y	Contract period
Dalmine Energia	Techint	Norway	0.6	Oct 2001 – Oct 2002
Dalmine Energia	Techint	Norway	1	9 yrs from 2002
Energia	CIR/Verbund	Norway	0.496 - 1.5 from Oct 2003 to 2005. It is in anticipation of Libyan gas (Greenstream)	4 yrs and 2 mths from Oct 2001
Energia	CIR/Verbund	Libya	0.5 from 2001 - 2 from Oct 2005 forward	24 yrs from Nov 2003
Edison	Italenergia	Norway	1.4	10 yrs from Oct 2001
Edison	Italenergia	Libya	4	24 yrs from Oct 2004
Edison	Italenergia	Algeria	In anticipation of Libyan Gas	4 yrs and 2 mths from Oct 2001
Plurigas	AEM Mi, ASM Bs, AMGA Ge	Netherlands	3	10 yrs from Oct 2001
Gaz de France	French state	Libya	2	24 yrs from Sept 2004
Total			**13**	

Source: Italian Industry Ministry

Tab. 8 - List of Major Importers to Italy, 2003

Wholesaler	Quantity Bcm/y
ENI	40.410
Enel Trade	9.092
Edison	5.880
Plurigas	3.062
Energia	1.183
Dalmine Energie	0.556
Gaz de France	0.579
Gas Natural	0.342
Energetic Source	0.313
Energas	0.253
Gaz de France	0.178
E Noi	0.186
Italcogim	0.165
World Energy	0.128
Hera	0.128
Blumet	0.117
Others	0.421
Total	**62.993**

Source: AEEG

The combination of direct imports and the gas released to third parties has allowed a number of operators to enter the Italian wholesale market, as shown in Table 5, even though majority control over imports is still in ENI's hands, which accounts for 64% of the imports listed in Table 8.

4.2 Potential New Competing Sources

New sources of supply to Italy could come from new imports, given the market opportunity presented by the projected decline in Italian domestic production (which is expected to fall from the current levels to 9-5 Bcm/y by 2015).

Given that the capacity of old gas entry points (77 Bcm/y according to ministerial sources) is fully committed by current imports or already signed LT contracts, additional supplies could only be absorbed by new import facilities. A number of projects have been proposed in order to satisfy the expected growth in Italian demand. They can be classified either as new LNG regasification terminals or as pipeline projects (expansion of existing interconnector pipelines or brand new pipelines). The first project to come on stream is **Greenstream.** Sponsored by ENI and National Oil Company (NOC), the Libyan state owned oil and gas entity, the €700 Million sub-sea Greenstream pipeline will convey some 8 Bcm/y of gas from fields in Libya to Sicily (Gela). The first deliveries started in October. In order to comply with the import ceilings, ENI has resold the associated gas purchase agreements to Gaz de France, Edison and Energia. The start of commercial operations at the Gela entry point has increased Italy's import capacity from 77 Bcm/y to 85 Bcm/y.

4.2.1 New LNG Regasification Terminals

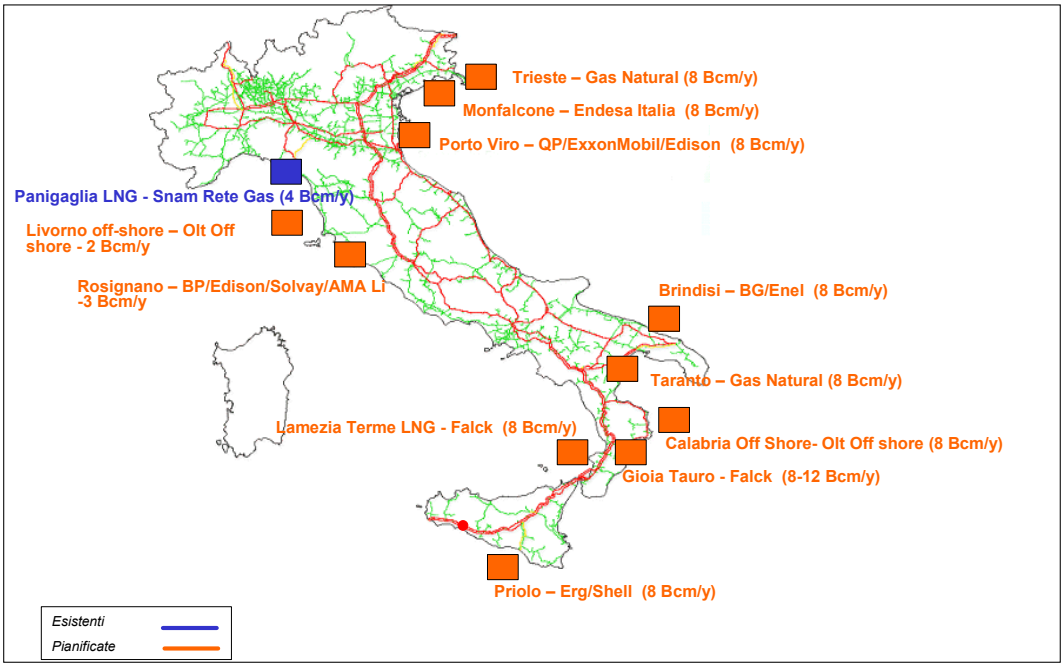
As part of their policy to diversify sources of energy supply into the country, many government bodies, including the Ministry of Industry, CIPE (the inter-ministerial body for economic planning), the Energy Regulator (AEEG) and the Antitrust Authority (AGCM) have expressed their support for the construction of new LNG regasification terminals.

As "**projects of national interest**", they are eligible for fast-track authorisation. The general public, however, has so far proved quite sensitive to the environmental issues involved. In 1997, after committing to purchase LNG cargoes from Nigeria, ENEL was failed to win approval for its proposed terminal and had to enter into fairly expensive swap arrangements with Gaz de France. Notwithstanding past failures, a number of LNG receiving terminals have been proposed, two of which have already been fully authorised.

These two projects are the 8 Bcm/y facility located at Brindisi, sponsored by a Joint Venture between Enel and British Gas, and the 8 Bcm/y Porto Viro (or NALT) offshore regasification terminal, sponsored by Exxon Mobil (45%), Qatar Petroleum (45%) and Edison (10%), from which Edison will be the principal off-taker.

As Figure 12 and Table 9 below show, there are nine regasification terminal projects that have been proposed but are at a less advanced stage since they are still in the lengthy approval procedure (Conferenza dei Servizi). Two of these projects are small offshore facilities, whereas the others are 8 Bcm/y onshore sites.

Fig. 12 - Proposed LNG Regasification Terminals



Tab. 9 - Proposed LNG Regasification Terminals

	Terminal	Sponsor	Capacity (Bcm/y)	Remarks
1	***Brindisi***	BG/Enel	8	Fully Approved, but new Regional Body wants to re-open the procedure
2	***Porto Viro***	ExxonMobil Qatar Petroleum Edison	8	Offshore Facility Fully approved
3	***Rosignano***	Edison – BP – Solvay-AMA Li	3	EIA obtained – Opposed by the Regional Body
4	***Lamezia Terme***	Cross Energy (Falck)	8-12	Two meetings of the Conferenza dei Servizi completed. Changes to the project requested.
5	***Gioia Tauro***	Gruppo Sensi	8 – 12	First meeting of the Conferenza dei Servizi completed. Changes to the project requested.
6	***Livorno Off shore LNG***	Cross Energy (Falck)	2	MOU with local authorities has been signed. EIA obtained. Three meetings of Conferenza dei Servizi held.
7	***Calabria Off shore LNG***	Cross Energy (Falck)	2	Three meeting of the Conferenza dei Servizi have been held
8	***Trieste***	Gas Natural	8	Project submitted recently. First Conferenza dei Servizi completed in September 2004
9	***Taranto***	Gas Natural	8	Project submitted recently. First Conferenza dei Servizi competed in September 2004
10	***Monfalcone***	Endesa Italia	8	Project submitted recently.
11	***Priolo Refinery Site***	ERG/Shell	8	Project submitted recently.

Source: Banca Intesa from various sources

4.2.2 Planned Import Pipelines

A number of pipeline projects have also been proposed. Two of the projects are expansions of existing import pipelines (TAG from Russia and Transmed from Algeria), one from Algeria (the Galsi project) and one transporting gas from the Caspian region (Italy-Greece-Interconnector, IGI).

TAG and Transmed de-bottlenecking

ENI and its international gas transport partners (Gazprom in Russia, Sonatrach in Algeria), have proposed the de-bottlenecking of both the TAG and Transmed pipelines, by 6 and 7 Bcm/y respectively. The probable low level of investment required and the favourable regulatory framework – granting reservation of 80% of capacity for international investments and thus allowing an increase in domestic capacity in Italy – has whetted the appetite for potential new supplies, which have already been placed with Italian off-takers. These investments are, however, under the control of ENI, which has no interest in creating a "gas bubble". ENI recently said that these projects could be delayed if both of the most advanced regasification terminal projects are successful.

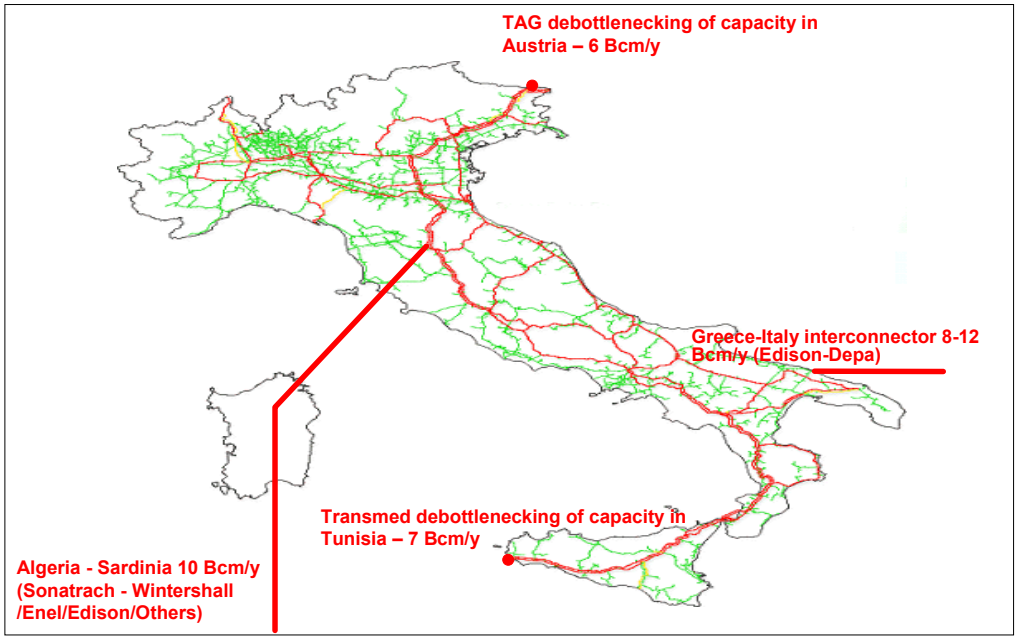
Algeria – Sardinia – France Pipeline

Sponsored by a joint venture called GALSI (between Sonatrach, Enel, Edison, Winthershall, EOS Energia, Sfirs and Progemisa), this project is still on the drawing board on account of its size and significant capital cost (c.€2bn). As a collateral benefit, it would create new gas markets in Sardinia (estimated demand c.1.5 Bcm/y), where there is no pipeline network.

Italian-Greece Interconnector

Sponsored by a joint venture between Edison and DEPA, this 8-10 Bcm/y project will transport the gas produced in the Caspian countries (Azerbaijan, Iran, Turkmenistan) to Italy, thereby opening the Italian and Greek markets to alternative sources of supply to their traditional suppliers (Algeria and Russia). IGI could be the first energy infrastructure project connecting EU consumer countries to the Caspian Region.

Fig. 13 - Planned Import Pipelines



Tab. 10 - Planned Import Pipelines

	Pipeline	Sponsor	Capacity (Bcm/y)	Remarks
1	***TAG Debottlenecking***	ENI	6	Dependent on ENI strategies and Antitrust decisions
2	***Transmed Debottlenecking***	ENI	7	Dependent on ENI strategies and Antitrust decisions
3	***Algeria-Sardinia-France***	GALSI (Edison ENEL Wintershall, Sonatrach, EOS Energia, Sfirs, Promegisa)	10	Feasibility study under way
4	***Greece-Italy Interconnector***	Edison/DEPA	8-12	Financing from EU obtained. Technical and financial feasibility studies under way

Source: Banca Intesa from various sources

4.3. Supply Forecast Scenarios

We have provided two supply scenarios: a base case and a gas bubble case.

In terms of assessing supply, a distinction must be made between the nameplate import capacity of a terminal/pipeline and the take-or-pay obligations (TOP) of the gas sales contract using this capacity. TOP obligations are based on how much gas from that source has to be bought i.e. the actual percentage of the Annual Contracted Quantity (ACQ)[10] that has to be taken or paid for. Our scenarios are developed in terms of the nameplate capacity, considering how hard it is to glean information on the details of gas supply contracts.

These form the basis of our gas prices scenarios.

In the base case, our assumptions are as follows:

- National production decreases from 13 Bcm in 2003 to 5 Bcm/y in 2015;
- 6 Bcm/y imported from Libya by 2005, increasing to 8 Bcm/y in 2006;
- 3 Bcm/y expansion of imports from Russia (already in process);
- Brindisi LNG operational from 2008[11];
- 8 Bcm/y from Qatar – regasified at Porto Viro LNG – by 2008.

Russia[12] and Algeria should maintain their dominant roles as major suppliers to Italy, exporting 25.5 Bcm/y and 26.5 Bcm/y (LNG included) respectively. Their market shares are however declining because of the entry of new suppliers. Major new exporter countries include Libya (8 Bcm/y from whenever the Greenstream pipeline is concluded), Norway (the existing contract should increase imports from 3 Bcm/y to 6 Bcm/y), Qatar (6.4 Bcm/y

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[10] *For simplicity's sake, we have assumed that the ACQ is equal to the nameplate capacity of the plant.*

[11] *Alternatively, if Brindisi does not proceed, we assume that an alternative LNG or pipeline project will be successful .*

[12] *Doubts are arising about the long term sustainability of supply from the huge Siberian gas fields e.g. Younburg and Urengory, given the lack of investment.*

landing at Porto Viro LNG terminal through an already signed off-take contract between QP/Exxon Mobil and Edison, although the additional capacity at Porto Viro is likely to be filled by additional Qatari gas), and Brindisi LNG (8 Bcm/y, of which we assume at least 80% will come from Egypt).

Note that the construction of the two regasification facilities will provide an additional 2.8 Bcm/y of spare capacity, available for spot LNG cargoes, as per AEEG requirements, so further supplies from new countries (Nigeria, UAE, Oman) are possible**.** Gas supply exceeds Italian demand (according to the base case scenario described in section 3.3) gradually from 2007 (+5 Bcm/y) to 2010 (c.10 Bcm/y), but the oversupply is forecast to diminish by 2015.

Tab. 11 - Base Case Forecast of Supply in terms of NIC by Country of Origin or Import Facility, 2003-2015 (Bcm/y)

(Bcm/y)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Domestic Production	13,6	12,9	12,1	11,2	10,4	9,6	8,8	8,0	7,4	6,8	6,2	5,6	5,0
ex-USSR	19,4	23,7	23,7	23,7	25,5	25,5	25,5	28,5	28,5	28,5	28,5	28,5	28,5
Algeria	21,5	24,0	24,0	24,0	24,0	24,0	24,0	24,0	24,0	24,0	24,0	24,0	24,0
Libya	-	-	6,0	8,0	8,0	8,0	8,0	8,0	8,0	8,0	8,0	8,0	8,0
Algeria LNG	2,3	2,3	2,3	2,3	2,3	2,3	2,3	2,3	2,3	2,3	2,3	2,3	2,3
Netherlands	7,3	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0
Norway	7,1	6,0	6,0	6,0	6,0	6,0	6,0	6,0	6,0	6,0	6,0	6,0	6,0
Nigeria (via France)	4,6	3,5	3,5	3,5	3,5	3,5	3,5	3,5	3,5	3,5	3,5	3,5	3,5
Brindisi LNG	-	-	-	-		8,0	8,0	8,0	8,0	8,0	8,0	8,0	8,0
Porto Viro LNG	-	-	-	-	-	8,0	8,0	8,0	8,0	8,0	8,0	8,0	8,0
Chg. in Storage	1,3	-	-	-	-	-	-	-	-	-	-	-	-
Total	**77,1**	**82,3**	**87,5**	88,2	89,7	104,8	104,0	106,3	105,7	105,1	104,5	103,9	103,3

Source: Banca Intesa estimates

We have also defined an alternative, **"gas bubble case"**. This scenario is determined on the following assumptions:

- that ENI implements one of its de-bottlenecking projects. For the purpose of this study, we assume Transmed de-bottlenecking in Tunisia (7 Bcm/y) from 2007;
- that one of the two new pipelines between the Italian-Greece Interconnector and Galsi comes on stream.
- that two of the currently non-authorised LNG regasification terminals come on stream; one of these is an offshore facility (2 Bcm/y, available from 2009) and the other is an onshore regasification terminal, available from 2013).

Tab. 12 - "Gas Bubble Case" " Forecast of Supplies in terms of NIC by Country of Origin or Import Facility, 2003-2015 (Bcm/y)

(Bcm/y)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Domestic Production	13,7	12,9	12,1	11,2	10,4	9,6	8,8	8,0	7,4	6,8	6,2	5,6	5,0
ex-USSR	19,4	23,7	23,7	25,2	25,5	25,5	25,5	28,5	28,5	28,5	28,5	28,5	28,5
Algeria	21,5	24,0	24,0	24,0	24,0	27,0	31,0	31,0	31,0	31,0	31,0	31,0	31,0
Libya	-	-	6,0	8,0	8,0	8,0	8,0	8,0	8,0	8,0	8,0	8,0	8,0
Algeria LNG	2,3	2,3	2,3	2,3	2,3	2,3	2,3	2,3	2,3	2,3	2,3	2,3	2,3
Netherlands	7,3	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0
Norway	7,1	6,0	6,0	6,0	6,0	6,0	6,0	6,0	6,0	6,0	6,0	6,0	6,0
Nigeria (via France)	4,6	3,5	3,5	3,5	3,5	3,5	3,5	3,5	3,5	3,5	3,5	3,5	3,5
Brindisi LNG	-	-	-	-	-	8,0	8,0	8,0	8,0	8,0	8,0	8,0	8,0
New import pipeline	-	-	-	-	-	-	8,0	8,0	8,0	8,0	8,0	8,0	8,0
Porto Viro LNG	-	-	-	-	-	8,0	8,0	8,0	8,0	8,0	8,0	8,0	8,0
Chg. in Storage	1,3	-	-	-	-	-	-	-	-	-	-	-	-
New Offshore Facility	-	-	-	-	-	-	2,0	2,0	2,0	2,0	2,0	2,0	2,0
New OnShore Facility	-	-	-	-	-	-	-	-	-	-	8,0	8,0	8,0
Total	**77,1**	**82,3**	**87,6**	**90,2**	**89,7**	**107,8**	**121,0**	**123,3**	**122,7**	**122,1**	**129,5**	**128,9**	**128,3**

Source: Banca Intesa estimates

4.4 Market Analysis - combining the demand and supply scenarios

Table 13 summarises our demand and supply scenarios in 2015 and Table 14 shows consequent overcapacity scenarios, calculated by comparing demand with supply.

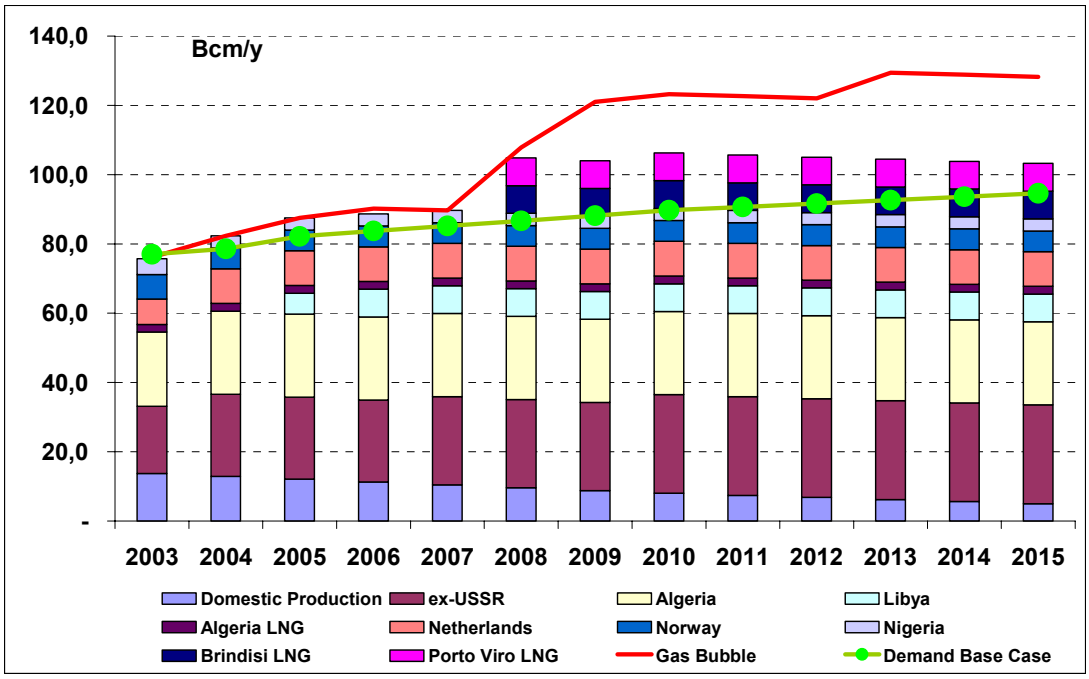
Tab. 13 - Demand and Supply Scenarios in 2015 (Bcm/y)

Demand Scenarios	Volumes	Supply Scenarios	Volumes
Worst Case	90.8	**Base Case**	103.3
Base Case	94.6	**Gas Bubble**	128.3
Best Case	103.8		

Tab. 14 – Overcapacity in 2015 in the Different Supply Scenarios (Bcm/y)

		Supply Scenarios	
		Base Case	Gas Bubble Case
Demand Scenarios	Worst Case	12.5	37.5
	Base Case	**8.7**	**33.7**
	Best Case	-0.5	24.5

Fig. 14 - Supply and demand scenarios



Of course, some of these scenarios are unlikely to materialise and are provided for the sake of completeness. We have cross-referenced our demand base-case scenario with the two different supply scenarios. On the basis of these overcapacity scenarios, we have determined our two gas price scenarios.

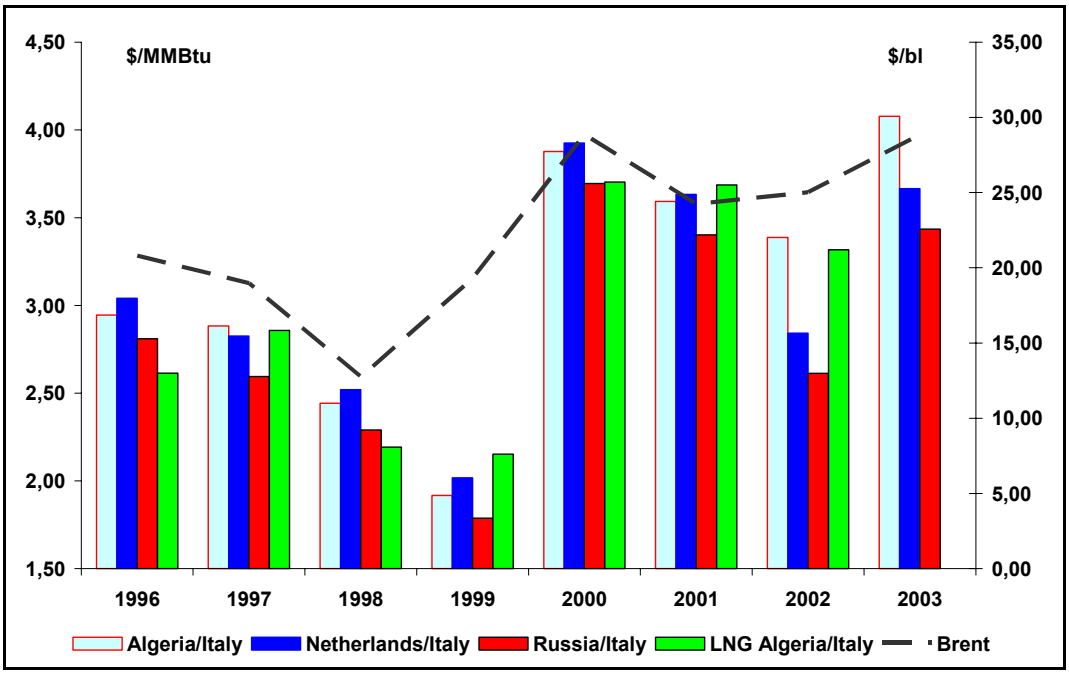
Note that the supply scenarios envisage an excess of supply on the Italian gas market. Whereas in the base case the excess supply may be absorbed by the Italian market, the gas bubble scenario is more significant. Using Italy as a “bridge” to consumer countries in continental Europe such as France, Austria, Switzerland, Germany could be an option to avoid the risk of Italian market overcapacity. In order to export gas to Europe, gas flows within Italy must be reversed from the existing system hub located in the Southern Po Valley to the Northern entry points. A first step towards Italy becoming a conduit for gas coming from North Africa or the Caspian is for the Italian gas system to establish a physical and contractual “hub” that should probably be located in the Po Valley area. The entire Italian gas system would have to be reconfigured around this new hub concept.

5. Market Analysis – Prices

5.1 Historical and Current Border Prices

Figure 15 shows the historical average annual border prices of gas from four sources i.e. three pipelines and LNG. The three pipeline sources are Algeria, the Netherlands and Russia. The prices of Algerian LNG exports to Italy are available only up to 2002.

Fig. 15 - Historical Average Annual CIF Border Prices of Some Import Contracts to Italy

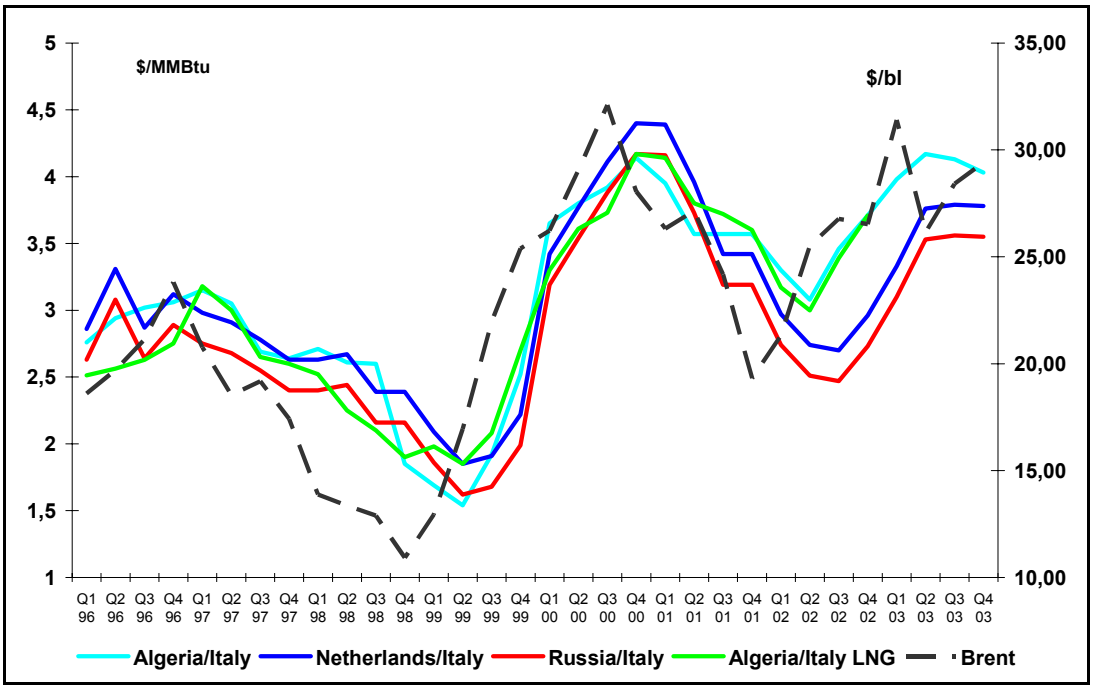


Source: Banca Intesa estimates on "Energia" data

The chart shows that border prices declined from US$3/MMBtu in 1996 to under US$2/MMBtu in 1999 and then rose to over US$3.50/MMBtu in 2000-1 and to c.US$4/MMBtu in 2003. Interestingly, the pipeline prices show little variation between sources when compared over time.

Turning to the average quarterly prices provided in Figure 16, the same down-up-down trend is evident. Pipeline prices tend to vary within a narrow band, as was the case with LNG up to 1999, at which point it became significantly higher before falling back into line with pipeline prices in 2Q01 and then rising again in 2H02 and 2003.

Fig. 16 - Historical Quarterly CIF Border Prices of Some Import Contracts to Italy



Source: Banca Intesa from various sources

The reason for this trend is self-evident, i.e. the linkage between gas and oil prices due to indexation formulas used in long-term contracts (called Sale and Purchase Agreements - SPAs).

Typically, gas SPAs include the following price clauses:

- The gas price is calculated on the basis of a formula providing a correlation with a basket of oil products that are gas substitutes, such as fuel oil and gasoil, and sometimes even a basket of crude oils.
- Price formulas often mimic the benchmarks used in the gas destination country, where this is available; in Italy the reference is the regulated upstream gas price called Qe[13].
- Prices are normally reviewed on a monthly basis, via a "backward looking weighted average" formula. Weights and lags are contracted between the parties; lags normally range from three to nine months.
- Reopening clauses to discuss possible changes to the price formulas are normally included in the contracts; these are envisaged every three/five years or in the event of a change in the law affecting the destination country.

5.2 Oil Indexation and Q_e

Italian tariffs for final customers are regulated and reviewed every three months – in respect of the component covering upstream costs - on the basis of an index set by the AEEG called Q_e, which mimics the structure of import contracts and represents the benchmark for the Italian border gas price.

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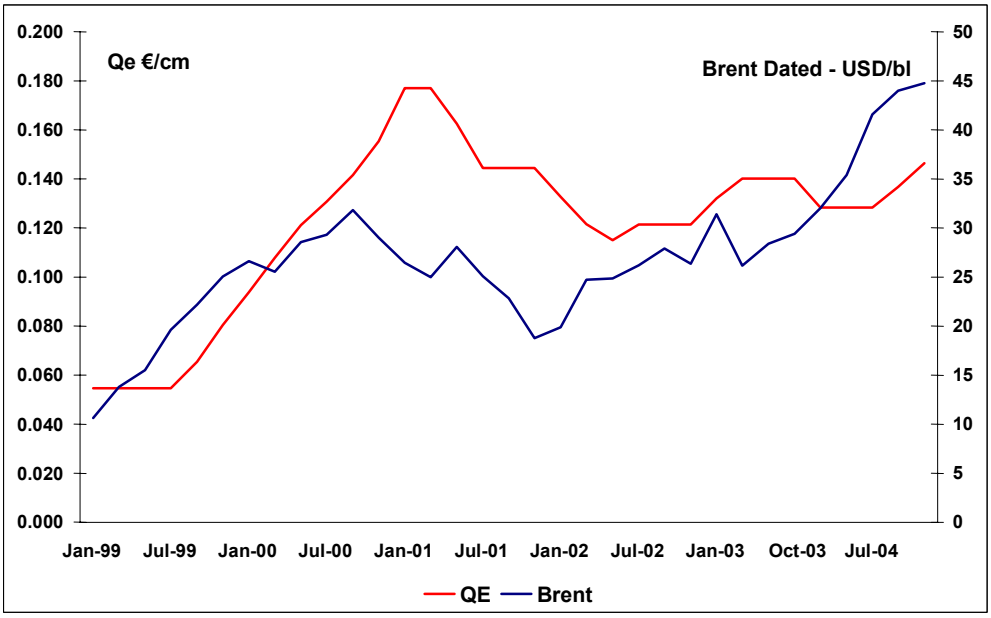
[13] *Qe represents the upstream component in the tariff regulated by the AEEG for residential and commercial customers.*

As shown in section 2.3.2/2.3.3, Q_e covers variable costs and provides indexation to international oil costs via its variable component (I_t), while CCI covers the international transportation costs. Looking at the past trend in the Q_e index, it clearly has a close correlation with Brent prices[14]. Q_e represents the starting point for calculating wholesale gas prices in Italy. This can basically be estimated by adding the commercial margin for wholesalers, which can be approximated using CCI, and the transport tariff within Italy to Q_e. This is due to the fact that the opening up of the market has still not had any effect on the price structure. Local distributors still supply the majority of final customers, and they still pay AEEG tariffs, based on Q_e. Consequently, Q_e still represents the benchmark for Italian border gas prices and for wholesale prices. Except for a few of the largest consumers, even consumers that have switched supplier are paying a discounted price compared with the Q_e tariff.

The following chart shows Q_e and Brent price since 1999.

Fig. 17 - Q_e Trend and Brent price



5.3 Other Charges – transportation tariff issues

Transportation tariffs are regulated and set out in AEEG Decree 120/01 and are updated by subsequent annual revisions through the application of the price-cap mechanism.

The transportation tariff components include:

1. A capacity charge (**Entry Point Charge**) set for the National Gas Network entry points;
2. A capacity charge (**Exit Point Charge**) set for the 17 National Network exit points to the Regional Gas Network (roughly one for each Italian Region);

[14] *The correlation between Qe and Brent (with 6 months lag) is over 90%*

3. A Fixed Charge (which varies between Snam Rete Gas and the Edison Transportation and Storage Network);
4. A capacity charge in respect of the Regional Medium Pressure Network;
5. A Storage Charge;
6. A Variable Charge for energy.

Of these, the entry and exit point charges are the most important. There are five entry points corresponding to the import points in Italy (Passo Gries from Northern Europe, Tarvisio from Russia, Mazara del Vallo from Algeria, Gela from Libya and Panigaglia, plus the existing LNG regasification terminal), two entry points corresponding to the Stogit and Edison storage facilities, and 68 entry points corresponding to domestic fields. Exit points exist for each Italian region.

Entry and exit point charges are inversely related from a geographic perspective, i.e. entry point charges are highest in the South while exit point charges are highest in the North of Italy. The analysis that follows demonstrates why these two components cause significant differences in gas prices between cities in different parts of the country.

To illustrate these differences, we have profiled a typical wholesale consumer, i.e. a power producer with a 400 MW CCGT power plant, 7,500 hours of use, 600 Mcm of annual gas consumption, 1.9 Mcm of capacity commitment at the entry point, 2.4 million cm of peak daily commitment and an 80% annual load factor, and who is connected to the High Pressure grid.

Based on this customer profile, we can determine the differences in transportation tariffs by analysing gas flows from two entry points (one in the North and the other in the South) to eight key cities in different parts of Italy.

Fig. 18 - Transport Tariffs from Tarvisio and Mazara del Vallo to Eight Key Italian Cities

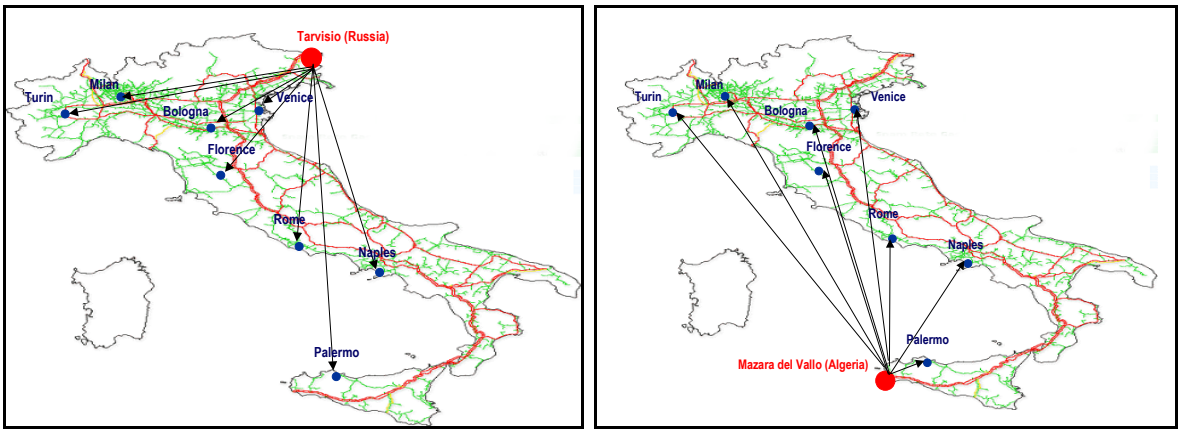
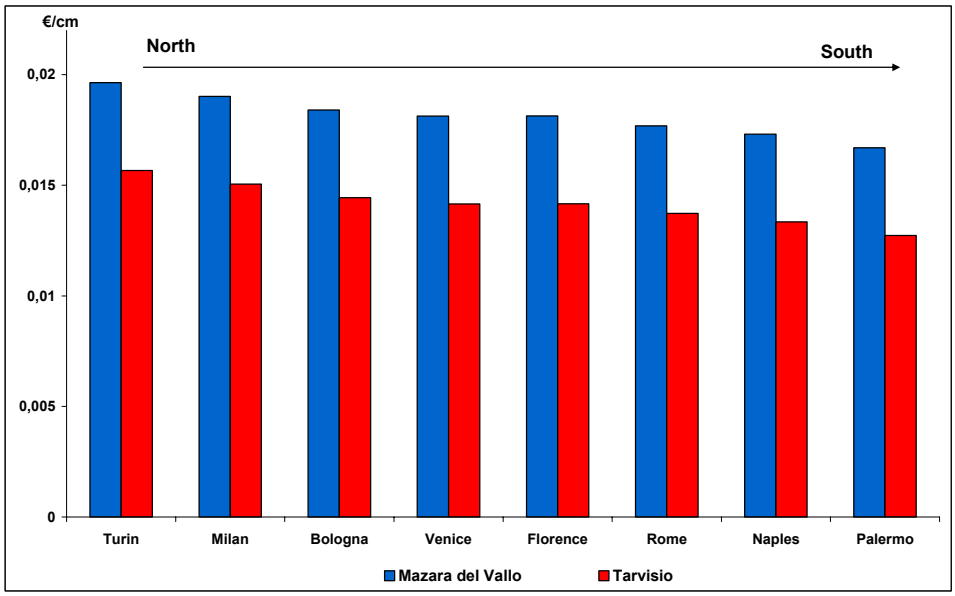


Fig. 19 - Comparison of Tariffs from Tarvisio and Mazara del Vallo to Eight Key Italian Cities



Two conclusions can be drawn from these calculations:

1. **Given the same exit point and consumer profile**, **the difference is due to the higher entry point charges**, which is the only component that changes. Higher entry point charges at Mazara del Vallo (and, in general, in the South compared with the North) are due to the greater distance of this entry point from the "hub" of the Italian gas system, which may be based near Minerbio in the Po Valley, where the largest storage sites are located. Higher entry point charges are, consequently, a competitive disadvantage for gas landed in the South of Italy.
2. **Given an entry point and a consumer profile,** the only component which changes is exit point charges, which are higher in the North than in the South. This can be seen by looking at how the red/blue histograms decrease from city to city moving from North to South in Figure 19. This is due to redistribution to avoid penalising consumers in the south. Exit charge re-distribution might however create some distortion (it is less costly to transport gas from Tarvisio to Palermo than from Tarvisio to Milan).

This is not considered significant by the Italian Regulatory Authorities, to the extent that Northern consumers are usually supplied by gas coming either from Russia or Northern Europe, while Southern consumers buy gas coming from Algeria. Considering that the majority of gas consumption is located in the North, it is the gas coming from Algeria that is currently supplying consumers in the South and centre of Italy. As a consequence, the Italian high pressure grid largely consists of gas flows entering from the South and flowing to the North. Additional entry points in the South could create system congestion, unless new investments in the Italian gas grid are made.

5.4 Effect of transportation tariffs on wholesale prices

Using an average entry point charge[15] and estimating the transport tariffs to a hypothetical exit point (which we may call the NBP or the National Balancing Point), which could be based in the Southern Po Valley region, it is possible to estimate an average transmission tariff within Italy. Assuming the same profile as above, this average transport tariff is **c.1.49 eurocents/cm** (or US$0.38/MMBtu).

This average transmission tariff is useful in understanding the competitive disadvantage that supplies accessing the Italian market from a new Southern entry point will have to face.

Transmission tariffs from the South are indeed generally higher than this hypothetical average value: we can simulate this by calculating the transport tariff from Mazara del Vallo to the NBP, which is 1.81 eurocents/cm ($0.47/MMBtu), i.e. 20% higher than the average transmission tariff.

By contrast, transmission tariffs from the North are lower than this average value: from Tarvisio to the NBP the transport tariff is 1.41 eurocents/cm (or $0.36/MMBtu). The North might therefore enjoy a competitive advantage compared to gas imported from the South.

The difference between Northern and Southern entry point charges might grow as additional volumes from the South enter the Italian system, and might potentially cause congestion.

5.5 Price Scenarios

The price formulas used in SPAs are obviously not known. It is possible to provide an estimation of the basic correlation between crude (i.e. the international crude benchmark, Brent Dated), and CIF gas prices/Qe via a model that takes into account:

- ❒ time lags from changes in oil and gas prices via indexation formulas;
- ❒ the effect of implicit correlation between the Brent price and the price of different oil products that are materially used in the index formulas.

The model allows to us to estimate gas prices depending on oil price scenarios. To the prices calculated as before we have added:

i) the commercial margin. We take as our starting point the value of 3.84 eurocents/cm[16] ($0.99/MMBtu) indicated by the AEEG in the transport tariff review of December 2003.;

ii) the average transportation tariff (1.49 eurocents/cm, or $0.38/MMBtu), described above, which we keep constant throughout the entire analysis period.

Two additional qualitative issues must be taken into account, however, namely the effects of gas-to-gas competition and possible overcapacity on the power market. Gas-to-gas competition could decouple gas and oil prices, whereas overcapacity on the power market could reverse the traditional price transmission mechanism (from power to gas instead of gas-to-power), modifying the traditional relationships in a way that is difficult to forecast.

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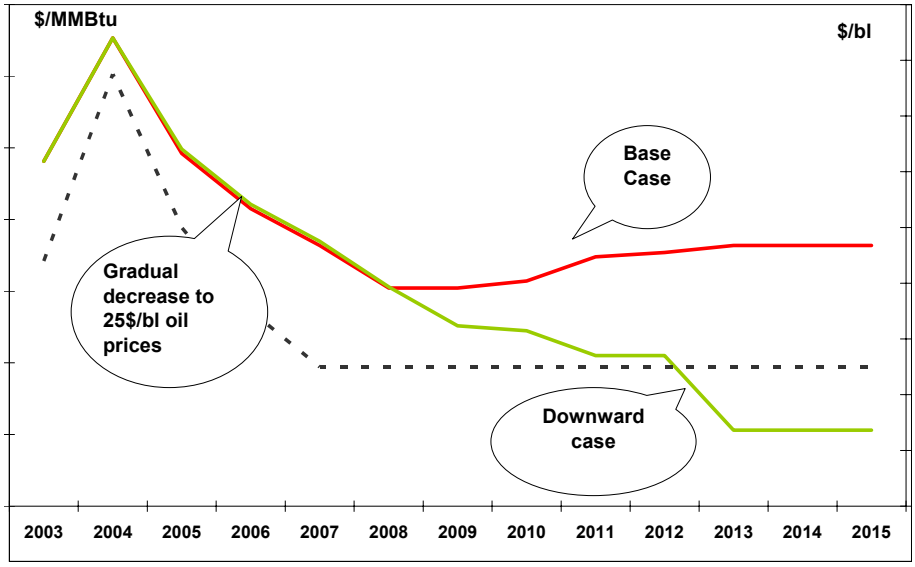
[15] *This is calculated as a weighted average on the basis of volumes metered at each entry point in 2003*

[16] *Given the current uncertainties related to the entry in force of the Deliberation 248/04, for the sake of this analysis we keep this figure.*

We present in qualitative terms two price scenarios based on our supply market assumptions:

Fig. 20 - Banca Intesa Forecasts for Italian Gas Wholesale Prices



Source: Banca Intesa

- **Our oil price scenario** is based on a gradual decrease from $37/bbl (full-year average in 2004) to a long-term equilibrium price of $25/bbl (from 2007). Since the supply scenarios are identical out to 2007, the fall in oil prices creates a reduction in wholesale gas prices from current levels in 2007 (the euro/dollar exchange rate is assumed to be 1:1). Thereafter, prices will move according to the two demand/supply scenarios, as follows;
- **In our base case,** gas prices will remain linked to oil, retaining the current relationship. The market will continue to be controlled by ENI, basically ensuring constant margins. However, the slight overcapacity between 2008 and 2011 and the number of new wholesalers competing for marginal quantities causes a certain degree of gas-to-gas competition, generating some slight pressure on sales margins. This sends wholesale prices down to a low in 2008-11. Thereafter, the excess capacity will be reduced and some of the new entrants are likely to leave the market; consequently, the pressure on margins might ease. Prices might stabilise or increase slightly.
- In our **downward case,** the excess import capacity puts further pressure on margins from 2009, and consequently causes a decoupling between oil and gas prices. In 2012 the coming on stream of a new 8 Bcm/y LNG regasification facility not only cuts margins practically to zero but forces the renegotiation of old contracts and a decoupling of oil and gas prices in new upstream contracts. Wholesale prices in 2015 are expected to be over 35% higher than our base case.

6. Conclusions

- The Italian gas market is generally regarded as one of the most dynamic in Europe. In 2003, Italy's gross gas demand amounted to 77.1 Bcm, the third largest in Europe. Italian gas demand in the next few years is likely to continue growing at a rate of c.2% p.a., second only to Spain among European countries. Demand is expected to reach c.90 Bcm in 2010 and c.95 Bcm in 2015.
- Gas prices for final consumers are high, but border prices are in line with the rest of Europe, relative to Italian power prices (which are significantly higher). However, the tax impact on household tariffs is costly, as taxation accounts for c.40% of final tariffs and is heavily differentiated on a local basis. Small industrial customers are also heavily penalised by taxation compared to their EU peers (35.9 vs an average of 24.4 eurocents/cm). Price differentials disappear for the largest industrial customers.
- The regulatory framework of the Italian Gas Market is laid down in the Marzano Decree, which converts EU Directive 98/30 into Italian Law. Subsequently, a number of detailed Laws and Resolutions by the AEEG built up a comprehensive set of rules; the most important include the restructuring of existing tariffs for final customers and the rules regarding the construction of new import LNG and pipeline facilities.
- Banca Intesa has developed different **gas demand scenarios**, basically based on its forecasts for development of the supply generation set. In its **Base Case** scenario, Banca Intesa forecasts growth in total gas demand from the current 77 Bcm/y to **94.6 Bcm/y,** driven by consumption for power generation purposes (expected to increase **from 26 Bcm in 2003 to 38.4 Bcm in 2015**). Two alternative scenarios, setting demand at 2015 at 90 Bcm and 104 Bcm in 2015, are provided.
- Availability of gas within the Italian system will be dependent on the development of import capacity, given that Italian gas fields are nearing depletion. A number of new import facility projects, both pipeline and LNG, have been submitted, but uncertainties about the success of these initiatives still persists.
- We developed two alternative scenarios, **a base case** and a **gas bubble case**, depending on how many new import facilities will come on stream. In the base case, supply availability is slightly over 103 Bcm in 2015, whereas in the gas bubble case the available supply in Italy exceeds 128 Bcm.
- Cross-referencing our supply with the base case demand scenarios, we defined **two qualitative price scenarios.** Matching the demand and supply base cases, we find that the current relationship between gas and oil prices should remain unchanged, and consequently prices movements should remain basically dependent on trends on the international oil market. Matching the demand base case with the supply gas bubble case, we found a marked overcapacity, which might put pressure on commercial and sales margins and could force a decoupling of the traditional relationships between the oil and gas markets. In this event, prices on the Italian gas market could dramatically collapse.

The Italian gas market is on the cups of a major transformation; the regulatory framework has been largely defined, and private investors are

trying to open up the market with a number of import proposals. Although competition on the Italian market has not been very intense until now, given that the large majority of gas flows is controlled by ENI, a number of wholesalers have started operating and may well continue to expand. Most important, Italy could change from a gas consumer market to a "consumer-transit" country, if new import infrastructure collecting gas from North Africa, the Middle East and the Caspian region is built, developing its position as a natural bridge in the Middle of Mediterranean and becoming a hub for gas transmission from Southern Europe to Central and Northern Europe.