

THE EUROPEAN FRAMEWORK

ELECTRICITY AND GAS PRICES

Eurostat statistics enable comparison of the prices Italians pay for electricity and gas—depending on type of customer, annual consumption, installed power and load factor—with those paid by Europeans in other countries. Italian prices are considered in relation to the European weighted average, calculated as a function of national volume-wise consumption in the year 2000 (separately for residential and business users). This allows for a fairer comparison of prices, since consumption varies considerably from one European country to another.

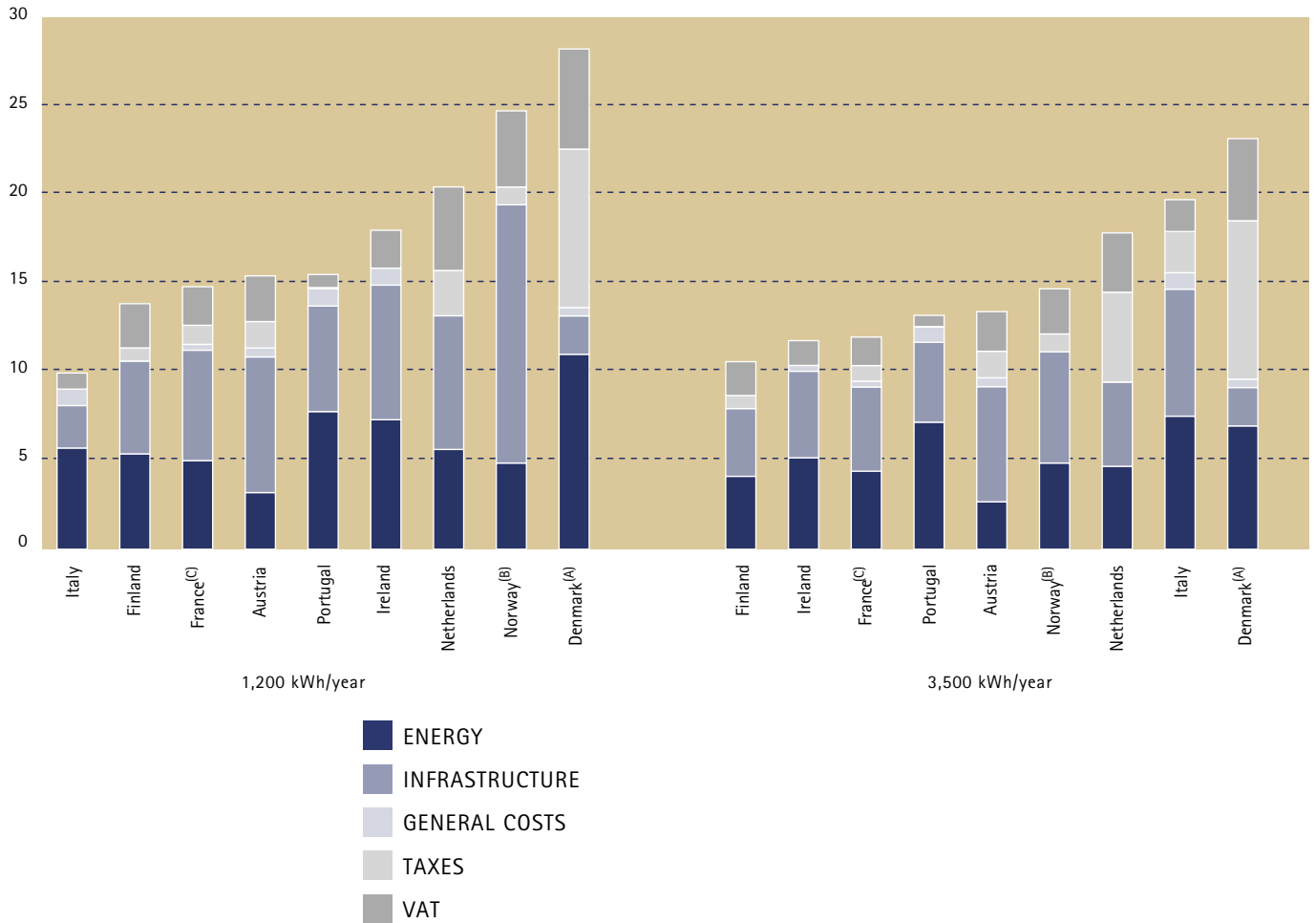
Prices are expressed in eurocents per kWh for electricity, and in eurocents per cubic metre for gas, by converting local-currency prices into euros at the fixed exchange rate in the case of eurozone countries and at the current exchange rate in the case of countries outside the zone.

Note that, according to the Eurostat definition, the price net of taxes has been stripped not only of bona fide taxes such as excise duties or VAT, but also of any other charge to the consumer that is not included in the industrial price (an “ecotax” is a good example). In Italy’s case this means that Eurostat, when reporting electricity prices, considers general system costs (components A and UC) to be fiscal components of the gross price and excludes them from the net figure. In addition, Eurostat prices do not include the initial hook-up charge. The gradual demand-side opening of the electricity and gas markets and the structural changes in supply have led tariffs, once set by monopoly rule, to evolve toward more complex pricing systems. Today’s Eurostat statistics reflect this complexity to a very limited degree. Most of the prices it reports, in fact, are regulated or reference prices (maximum or recommended tariffs), and in rare cases only does it report the prices freely negotiated between the parties. Although prices should reflect the most representative market rates for a given supply of electricity or natural gas, often they are simply the prices charged by the former monopoly holder, which tend to lose significance as the incumbent loses shares of the market.

To improve the quality of its data, in 2002 Eurostat set up a task force that proposed an alternative price tracking method. After an initial trial phase, the method should be fully incorporated as from 1 July 2007, coinciding with the complete liberalization of the electricity and gas markets. The Council of European Energy Regulators (CEER), a member of Eurostat’s task force, recommended the breakdown of final electricity prices into five components: energy (including both fixed generation costs and variable costs), network infrastructures, general costs (surcharges, ecotaxes, stranded costs, etc.), excise duties and VAT. This method, aimed at making prices more comparable within Europe, is being used on a preliminary basis in certain countries. The results are shown in Figures 1 and 2.

FIG. 1 **BREAKDOWN OF ELECTRICITY PRICES BY CLASS OF CONSUMPTION:
RESIDENTIAL USERS**

Prices in eurocents/kWh as of 1 July 2003



(A) Average for 2002.

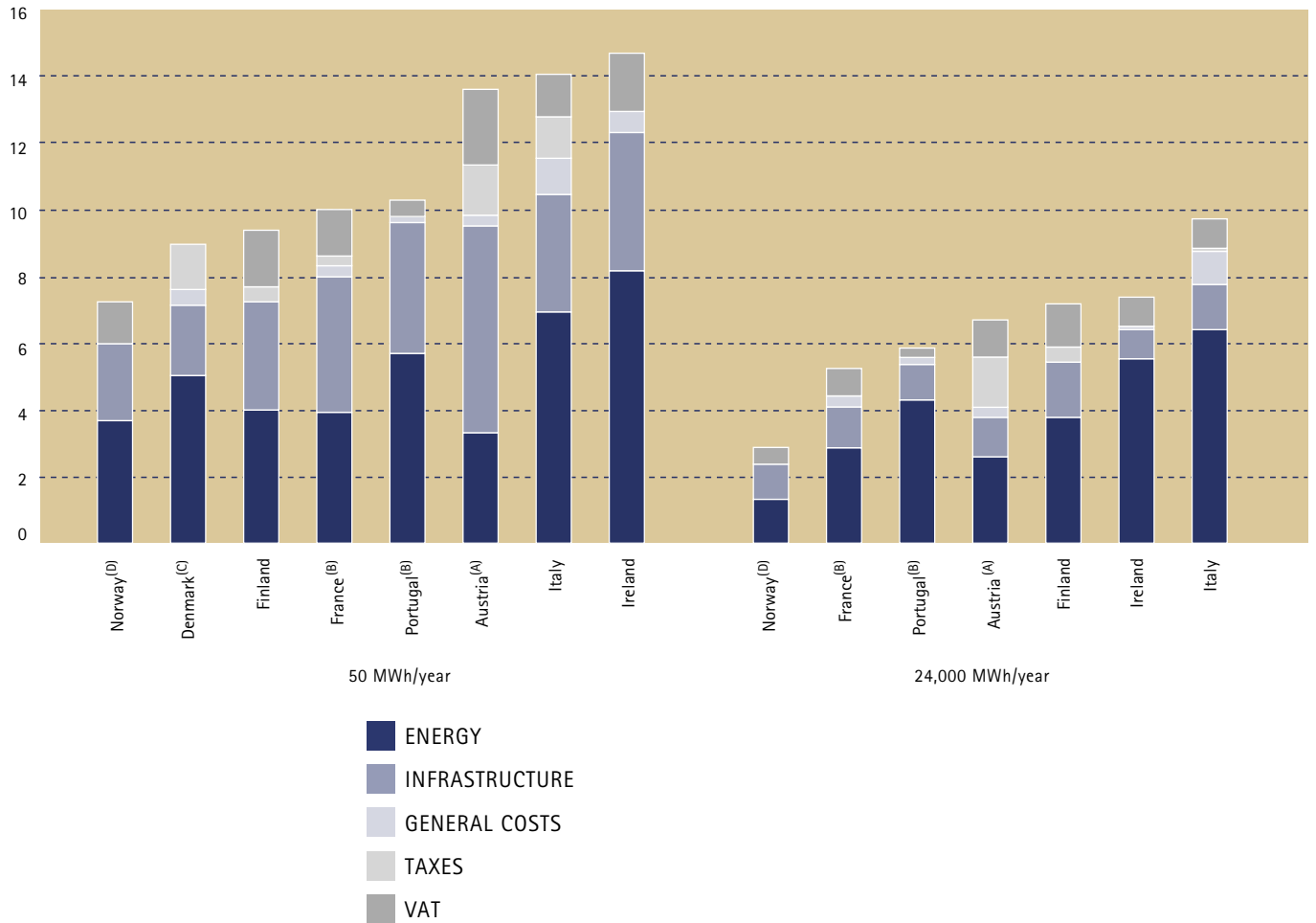
(B) Average for 2003. For Norway, general system costs are included in the "infrastructure" component

(C) Start of 2003.

Source: AEEG calculations on Eurostat and CEER data.

FIG. 2. **BREAKDOWN OF ELECTRICITY PRICES BY CLASS OF CONSUMPTION:
BUSINESS USERS**

Prices in eurocents/kWh as of 1 July 2003



(A) Average for November 2003.
 (B) Start of 2003.
 (C) Average for 2002.
 (D) Average for 2003. For Norway, general system costs are included in the "infrastructure" component.

Source: AEEG calculations on Eurostat and ISTAT data.

ELECTRICITY PRICES

Prices for residential users

Eurostat figures for residential users refer to four classes of annual consumption: up to 600 kWh, 1,200 kWh, 3,500 kWh and 7,500 kWh. Prices for July 2003 confirm the Italian peculiarity of a progressive tariff structure (magnified by the tax system, which does not strike the lowest levels of consumption) by which the unit price of electricity rises with an increase in annual consumption, at least up to a certain point. Italians who consume less power—up to 600 and 1,200 kWh—are charged much lower prices (both gross and net of taxes), sometimes as little as half of other tariffs in Europe. Those who consume more suffer the opposite: Italian prices are well above the European average, namely 47 percent higher in the 3,500 kWh class and 54 percent higher for consumption of 7,500 kWh per year (prices gross of taxes).

Prices for business users

Prices for business users (i.e. all users other than residential—in industry, services and agriculture) are compared on the basis of seven classes of consumption, from 50 MWh to 70 GWh per year.

For Italian businesses, prices both gross and net of taxes are consistently above the European average. The difference, gross of taxes, is smaller for lower classes of consumption and larger for major consumers. In percentage terms the gap is widest for the three intermediate classes (2, 10 and 24 GWh per year). Net of taxes, Italian prices are even farther from the European average, mostly because taxes account for a smaller proportion of the prices paid by large-scale consumers.

GAS PRICES

Prices for residential users

For households where gas is used mainly for cooking, Italian prices gross and net of taxes are among the lowest in Europe. Households that also use natural gas for heating see some of the highest rates gross of taxes, preceded only by Sweden and Denmark, with a differential of more than 50 percent on the average European price. Because of Italy's heavy fiscal charge on these classes of consumption (2,200 and 3,300 m³ per year), the gap net of taxes comes down to about 20 percent.

Prices for business users

For business users consuming the least, Italian prices are among the highest in Europe, at 13 to 17 percent more than the European average gross of taxes and 20 to 25 percent more on a net-of-taxes basis. On the other hand, unlike for residential rates, gas prices for business users differ less from the European average once they fall into the higher classes of consumption. For businesses consuming more than 10 million m³ per year, the price gross of taxes is 5 percent higher than the weighted average, while for those with an annual consumption of around one million m³ the gap is actually negative.

For business users in Italy, whatever their class of consumption, taxes account for some 5 percent less of the total price than in Europe as a whole.

THE ITALIAN FRAMEWORK

ENERGY POLICY IN THE CABINET AND PARLIAMENT

Legislative changes in the energy sector

The main legislative changes between 30 April 2003 and 30 April 2004 were the government interventions triggered by the planned power outages in June 2003 and the blackout of September; preparatory activities for the Power Exchange; and Legislative Decree 387 of 29 December 2003, which incorporated the European Directive (2001/77/EC) on the promotion of electricity made from renewable sources, as described further in this report. Other measures concerned the allocation of imported power for 2004 by the Ministry of Productive Activities, the treatment of stranded costs and hydroelectric revenue, auctions for CIP6 subsidized energy, and special rates for energy-intensive businesses based on the islands.

Planned outages and the blackout

In response to both the planned power outages performed by the Italian transmission system operator (GRTN) on 26 June 2003 and the discrepancy between required and available power, the Cabinet adopted Decree Law 158 of 3 July 2003: “Urgent measures to guarantee the secure and continuous supply of electric power”. The decree, on an extraordinary basis for 75 days, modified the thermal discharge temperature limits for thermoelectric power stations rated above 300 MW to allow them to stay in production.

Considering the length of the heat wave and the lack of rain, with Decree Law 239 of 29 August 2003 (“Urgent measures for the security of the national electric system and for the recovery of electric power”) the government intervened once again to alter the operating conditions of Italy’s thermoelectric plants. This time, at the initiative of GRTN, thermoelectric plants rated above 300 MW were allowed to operate until 31 December 2004 outside the emission and air quality standards laid down in their authorization documents, although within the emission limits for plants smaller than 500 MW as set by European law.

Due in part to the system-wide blackout that occurred the night of 27–28 September 2003, when Decree 239/03 was converted into law the Cabinet was given special authorization to ensure the achievement and maintenance (including for the medium term) of the economic conditions needed to guarantee the sufficient production of electric power. Specifically, within two months it had to come up with a competitive system for the remuneration of production capacity, as well as measures to streamline, unify and simplify the procedures for building network infrastructures.

In practice, the conversion of the decree into law was an opportunity to pass energy planning legislation as well. The new law was expanded with measures that Parliament had long been debating in the context of the energy bill (AS 2421). In addition to extending the permission to exceed emission limits granted by Decree Law 239/03 until 30 June 2005, the conversion measure—Law 290 of 27 October 2003—gave the Cabinet broad authorization with respect to:

- rescheduling production by hydroelectric plants, concentrating maintenance on and reactivating plants long held dormant, and increasing interruptible capacity in order to reduce the risk of widespread outages;
- reunifying grid ownership and management, to be followed by privatization and guarantees of an independent grid.

Concerning this latter point, the Cabinet was asked to establish the criteria, procedures and conditions for uniting the ownership and management of the national transmission grid (by means of a Prime Minister's decree to be issued within 60 days of the enactment of Law 290/03), and to oversee the resulting body, including with regard to voting rights and subsequent privatization. Law 290 also attributed certain powers to the Ministry of Productive Activities, in connection with:

- guidelines for the development of the national electricity and gas transportation networks, and the approval of the annual development plans submitted by the network operators;
- the forfeiture of permits for the construction of new power stations and LNG regasification plants if work is not begun within 12 months;
- the shutting down, after consulting GRTN, of plants rated higher than 10 MW;
- GRTN's access to pumping plants for the management of surges and peak demand, as well as their remuneration, during that period, at the price attained through the bidding system;
- the allocation to the Electricity and Gas Authority of the imports previously allotted by Legislative Decree 79 of 16 March 1999, which in accordance with the new European law (Directive 2003/54/EC) are to be allocated to the national regulatory authority;
- the exemption from third-party access of newly built interconnection networks, a subject already governed by the Authority but for which the new European discipline requires specific authorization by the national regulatory authority;
- simplifications to the authorization process for electricity transportation networks and plants of more than 300 MW power.

With Legislative Decree 379 of 19 December 2003 ("Measures for the remuneration of electricity production capacity"), the government spelled out the need to design a system that would pay companies for making production capacity available, to ensure that domestic demand could be met while maintaining the necessary reserves. The system will have to be based on competitive, transparent, non-discriminatory mechanisms that do not distort prices on the market and that minimize the cost to consumers. Using the basic criteria to be defined within three months by the Authority, GRTN will have a further three months to outline a proposed remuneration system, which will then be approved by the Ministry of Productive Activities (with the Authority's input) along with the designated powers of

Start-up of the electricity market

GRTN and the Market Operator (Gestore del Mercato Elettrico Spa, or GME). The decree also defines GRTN's inspection and monitoring duties, and a system of penalties to be enforced by the Authority. Lastly, it establishes transitional measures for the period before the remuneration system takes effect. In that connection, the Authority is to set temporary compensation levels for capacity made available at plants that is dispatchable and usable on the days of the year that GRTN identifies as crucial for the satisfaction of demand.

In addition to Legislative Decree 379/03, the main legislative changes that have permitted the start-up of the organized electricity market are as follows: the Trade Ministry decree of 19 December 2003, which puts its own duties into the hands of the Single Buyer (Acquirente Unico Spa) with effect from 1 January 2004; and another Trade Ministry decree of 19 December 2003, which approved the market regulations and the means by which GME would take charge of the market as from 8 January 2004.

Under the first of the two decrees, the Single Buyer, as guarantor of the supply of electricity to captive market customers, is charged mainly with estimating these customers' demand; the decree also defines the procurement system (bilateral contracts on the free market for quantities not exceeding 25 percent of estimated demand, participation in transport capacity allocation procedures for imports, as well as in CIP6 auctions and the bidding system according to standards set by the Authority). In addition, the measure attributes to the Single Buyer the long-term import contracts signed by Enel Spa before 19 February 1997 at the wholesale electricity price for the quarter October-December 2003 (subject to adjustments). The Single Buyer will receive 50 percent of any benefit obtained from the renegotiation of those contracts.

The decree approving the Power Exchange regulations and the Market Operator's responsibilities also defines the nature and frequency of the information that GME has to provide for the sake of monitoring. In particular, GME must provide the Ministry of Productive Activities and the Authority with a quarterly report on the market's performance and on any reasons why the market regulations should be changed. It must also inform the ministry, the Authority and the anti-trust authorities of any inappropriate or irregular situations that emerge in the market. On the basis of standards set by the Authority, price indices for the electricity market are created by the market operator and transmission system operator (GME and GRTN); lastly, the Authority must devise a system for keeping market powers in check and for monitoring the course of prices.

Regional and local energy policies and laws

The amendment to Section V of the Italian Constitution, passed with Constitutional Law 3 of 18 October 2001, significantly altered the powers of the regions and gave them a new,

more active role (within the framework of the national legislative system) in setting energy policy. The revised Art. 117 of the Constitution gave the regions concurrent legislative power over the production, transport and distribution of energy, while leaving the basic principles (national security, competition, interconnections, and the overall management of environmental issues) up to Rome.

Regional governments can now use energy plans as tools for the development of their entire energy systems, in keeping with business and socioeconomic advancement. In many regions (Piedmont, Lombardy, Tuscany, Valle d'Aosta, Trento, Bolzano, Calabria, Lazio, Basilicata, Sardinia and Emilia Romagna), energy plans have been approved by at least one of the regional authorities; in all others they are in the process of definition or development.

Some regions have also submitted plans to the Authority for its comments and suggestions. Of the primary objectives evident in the plans, one that deserves praise is the will to pave the way for the growth of an energy system that gives preference to renewable sources and conservation for the sake of a healthier environment. According to the plans, critical actions for achieving that goal include—on the demand side—incentives for reducing final energy consumption (for business, civil use and transportation), and—on the supply side—bolstering the use of renewable sources, transforming fossil fuels into energy more efficiently, and fostering technological innovation and research (use of hydrogen and new eco-friendly fuels). In brief, these regional energy/environmental plans address the emergencies and new needs dictated by national and European legislation, and denote the regions' deep involvement in developing local energy and environmental systems and their acceptance of full responsibility within the context of the national and European course of action.

Of particular note is Lombardy's Regional Law 26 of 12 December 2003: "Discipline of local services of general economic interest; rules for the management of waste, energy, use of the subsoil and water resources". In addition to describing the distribution of powers between towns, provinces and the region, this law emphasizes the need to assure citizens efficient, high-quality utilities. This is an aspect that the Authority takes to heart, seeing it as a chance to work with the region to obtain the desired results without making services more costly.

Sicily is worth mentioning for its Regional Law 2 of 26 March 2002, which at Art. 6 established an environmental tax for the owners of regional gas pipelines. The Authority intervened at the time with Resolution 113 of 20 June 2002, consisting of a report to Parliament which argued that some provisions of the Sicilian law were improper to the extent that they would seriously hinder the liberalization and greater openness of the natural gas market, both national and European, and might also prejudice a secure supply.

The Sicilian law was recently blocked by the Provincial Tax Commission of Palermo, which not only declared it invalid, but ordered the region to reimburse Snam Rete Gas Spa for the tax of 10.8 million it had paid in April 2002. That ruling is fully in line with the stance taken in Brussels, which is to treat the environmental tax as invalid because what it boils down to is an import duty on Algerian natural gas.

This case is a clear demonstration of the need for central and peripheral administrations to work together. Such efforts, without violating the spirit of the reform, can foster regional initiative in the context of collaboration among the various levels of government. The Authority is doing its part to achieve this. One of its priorities is to foster relations with regional governments, both directly and through existing bodies, and it is also experimenting with a liaison procedure that would make it formally possible to obtain the regions' opinion on guidelines for the design, execution and final evaluation of the conservation projects disciplined by Art. 5, par. 5 of the ministerial decrees of 24 April 2001.

Incorporation of the European directive on renewable sources

European Directive 2001/77/EC, on the promotion of electricity made from renewable sources within the internal power market, was incorporated into Italian law with Legislative Decree 387/03. The directive, while setting a target for the development of renewable energies for the year 2010—as a percentage of the gross domestic consumption of countries in the European Union—asks member states to take specific measures concerning the guaranteed origin of renewable energy, authorization procedures for renewable power plants, network access, and monitoring of the member states' progress toward their targets.

Legislative Decree 387/03 states that:

- for output exceeding 50 MWh/year, the transmission system operator (GRTN) is in charge of issuing a certificate of origin to renewable producers who request it. Certificates of origin, not to be confused with green certificates, state the plant's location, the renewable energy source, the technology used, the nominal power of the plant, its net output or, in the case of hybrid plants, the output from renewable sources. The certification system is important both to the institution of voluntary renewable energy markets ("green pricing" arrangements) and to a European renewable energy market, in that it prevents exported renewable energy from being counted twice and affords a basic level of country-to-country reciprocity;
- in order to speed up the authorization process, renewable plants are treated as urgent and non-delayable public works. This means that a single permit is required, which must be granted by the region or its deputized organ within 180 days of the application date. In addition, authorization cannot be subordinated to compensation schemes for regions and provinces;
- by May 2004, the Authority would have to adopt specific measures specifying the technical and economic conditions for the connection of renewable plants to electrical grids with nominal voltage greater than 1 kV, whose operators are obliged to allow hook-ups by third parties. Transparency is the rule, and is assured by the publication of technical standards, connection times and fees.

In addition to incorporating the European regulations, Legislative Decree 387/03 governs the renewable-energy aspects of the Power Exchange that were left unresolved during the liberalization process, and introduces provisions specific to each kind of renewable source.

The decree also makes some changes to the green certificates market and to the procedures for remunerating renewable-source plants for their output.

Three aspects are worth noting as concerns the green certificates market. Art. 4, par. 1 of the decree calls for an annual 0.35 percent increase in the obligatory quota for the period 2004–2006, with respect to the original 2 percent set in Legislative Decree 79/99. It also sets the deadlines by which the increases for the periods 2007–2009 and 2010–2012 will be updated. In the second and third paragraphs, Art. 4 goes on to state that the Authority will fine parties who fail to comply with the green certificates requirement, pursuant to Law 481 of 14 November 1995.

Art. 20, par. 7 of the decree extends the validity of green certificates from one year (as established in Legislative Decree 79/99) to three. That change will help reconcile the supply and demand of green certificates from the perspective of timing. In other words, if in one year the demand for green certificates is lower than the supply, the unsold certificates can be marketed during the next two years instead of being cancelled.

Lastly, par. 6 of the same article allows green certificates to be issued for biomass- and waste-fuelled plants for a period longer than eight years, which is the time limit for other sources of renewable energy.

As for the sale of electric power, the decree states that renewable plants rated less than 10 MVA, and all non-programmable plants that do not fall under other incentive schemes, will be remunerated under the terms established by the Authority on the basis of market conditions. According to the first paragraph of Art. 20, until the Power Exchange is up and running—and in any case while the current ministerial decree remains valid—starting as from 1 January 2004 energy from renewable plants rated less than 10 MVA and from all non-programmable plants will sell for the wholesale electricity price.

Special regulations

Decree 387/03 also regulates specific technologies. Art. 7 mentions a subsequent decree, to be issued within six months, that will establish special incentives for solar power. For photovoltaic energy, in particular, there will be an energy grant as opposed to the capital grant originally envisaged in the project “10,000 solar roofs”, so as to ensure fair compensation for investment and operating costs.

By August 2004, the Authority must extend on-site trading authorization to all renewable plants rated less than 20 kW (such a system was previously in place for photovoltaic plants only, as per Resolution 240 of 13 December 2000). On-site trading is defined as the sale of energy by the renewable plant to the local distributor and free-of-charge withdrawal for volumes up to the full amount injected.

Dispatch priority will be granted to hybrid plants, i.e. those that generate power using both renewable and non-renewable sources whose output from renewable sources amounts to at least 50 percent of the total.

In accordance with the European Directive, the decree confirms that waste is to be considered as a renewable energy source. For practical reasons, the decree extends preferential treatment to non-biodegradable waste. In essence, then, non-biodegradable waste will be eligible for renewable-source incentives in terms of both market access rules and green certificates. By June 2004 the Ministry of Productive Activities, in concert with the Ministry of the Environment and the Unified Conference, are to issue a decree defining the waste and waste-derived fuels that are eligible for the benefits, as well as the emission limits for the plants and the means of ensuring compliance with Europe's "waste hierarchy". On that note, European Directive 75/442/EC instituted a hierarchy of waste treatment that favours re-use and recycling over combustion. Access to renewable source incentives, if not handled properly, could upset the economic benefit in relation to the treatment hierarchy.

STRUCTURE OF THE MARKETS AND REGULATION OF THE ELECTRICITY SECTOR

CHANGES IN THE MARKET IN 2003

For the electricity sector, 2003 was the most challenging year since 1996, when Italy began the long march toward liberalization.

The problems were caused less by the process of defining new rules than by the overlapping of precise exceptional circumstances with the structural weaknesses of the Italian system.

The demand for electric power in recent years has risen fast, especially in comparison with economic growth, and the upswing during the summer months has been more dramatic than expected. This has put the system under pressure at a particularly delicate moment during the process of renewing the country's power facilities.

Other structural problems—the continued presence of a dominant utility, costly CIP6 subsidies, and the dependence on imports—compounded contingent circumstances such as the high price of fossil fuels on the international markets, the unavailability of sizable portions of the system due to conversion projects, and the scarce precipitation. The heat wave in the summer of 2003 made a bad situation worse, causing a further rise in peak demand and a decrease in available supply from both hydroelectric and thermoelectric plants.

The most visible effects of these factors were the service interruptions the country experienced in June 2003. Simultaneously with the crisis, the electricity sector made several advancements in the transition from a vertically integrated system to a liberalized market, at least for the activities that do not constitute a natural monopoly.

One crucial achievement was the start-up of the Power Exchange, albeit in transitional form. The Power Exchange is indispensable for allowing electricity to be purchased on the basis of market mechanisms. Previously, in fact, although production was a free enterprise pursuant to Art. 1 of Legislative Decree 79 of 16 March 1999, the generation price was still regulated from above.

Since the electricity market opened on 1 April 2004, the Authority for Electricity and Gas has no longer been responsible for defining the generation cost, which is now set by a system of competitive bidding. In other words, the Authority has less need to control the electricity generation price which, thanks to market competition, should settle down to a level more in line with the real cost of generation.

Before the Power Exchange could fully take effect, however, it had to go through a transitional period, which lasted for all of 2003 and early 2004. This was also an especially difficult time for the fundamentals of the electricity sector.

The outages of 26 June and 28 September 2003 were a dramatic illustration, at two completely different times in terms of demand, of the national electric system's most serious weaknesses. They imposed regulatory efforts that paralleled the completion of the liberalization process and that were just as urgently needed.

The planned interruption in June took place when summer demand was high—as it has been for the past several years, in a trend national output has not been able to match. Con-

versely, the September blackout was caused by a natural event that interrupted procurement from abroad, demonstrating the inadequacy of Italian reserves even when demand is low. In both instances, the Authority decided to perform fact-finding missions before deciding how the various parties were responsible and what kinds of conduct may have caused (or failed to prevent) the blackouts.

When it came to regulation, the official functions of these efforts, as defined in the Authority's founding law (Law 481 of 14 November 1995), had to be reconciled with the immediate needs of the system. Therefore, in the various parts of the electricity sector, the Authority decided to take action designed to manage the emergency for the short term while normalizing conditions for the long term, in accordance with the guidelines set by the Ministry of Productive Activities. On the production side, it introduced a provisional "capacity payment" system in an attempt not to burden consumer tariffs that were already rising under the pressure of the growing cost of fuel.

On the demand side, the Authority focused on rationalizing interruptibility. As expressly requested by the transmission system operator (GRTN) in a letter of 16 December 2003, it authorized interruptible power without notice of 1,750 MW and a with-notice limit of a further 1,750 MW. A remuneration system was then introduced for end customers able to provide that service.

For the long term, investment-friendly regulations were needed to address the problem of the insecure supply. With the definition of measures for regulatory period 2004–2007 and approval of the new consolidated act on tariffs, investment incentives were introduced in the transmission and distribution sector by raising the rate of return on invested capital and offering a 2-point spread on the base rate for new investments in the national transmission network. To maintain a balance between investment needs in the sector and the electricity tariff, this move was offset, in terms of costs, by boosting productivity and efficiency and adjusting the useful life of infrastructures as recognized for tariff purposes.

Through the use of bilateral contracts, import agreements, supplies of CIP6 power and contracts for differences, the Single Buyer (a company called Acquirente Unico Spa) procured more than 60 percent of its power at a level established under the terms of the previous regulatory period. The measure was necessary during this transition phase, until the electricity sector is developed enough—in particular, until enough new plants are in operation—for Power Exchange prices to be influenced more by actual production costs and less by the incumbent's strategies.

The transition phase is resulting in major changes to the functional set-up of the market. To understand how it has evolved, we need to take a close look at the relationships between institutional parties and stakeholders. The following diagrams show the current structure of the Italian electric system, with the economic flows among the various parts of the production chain highlighted in the first, and the functional relationships between the production chain and institutional players in the second.

FIG. 3 ECONOMIC FLOWS IN THE ELECTRICITY SECTOR IN 2003

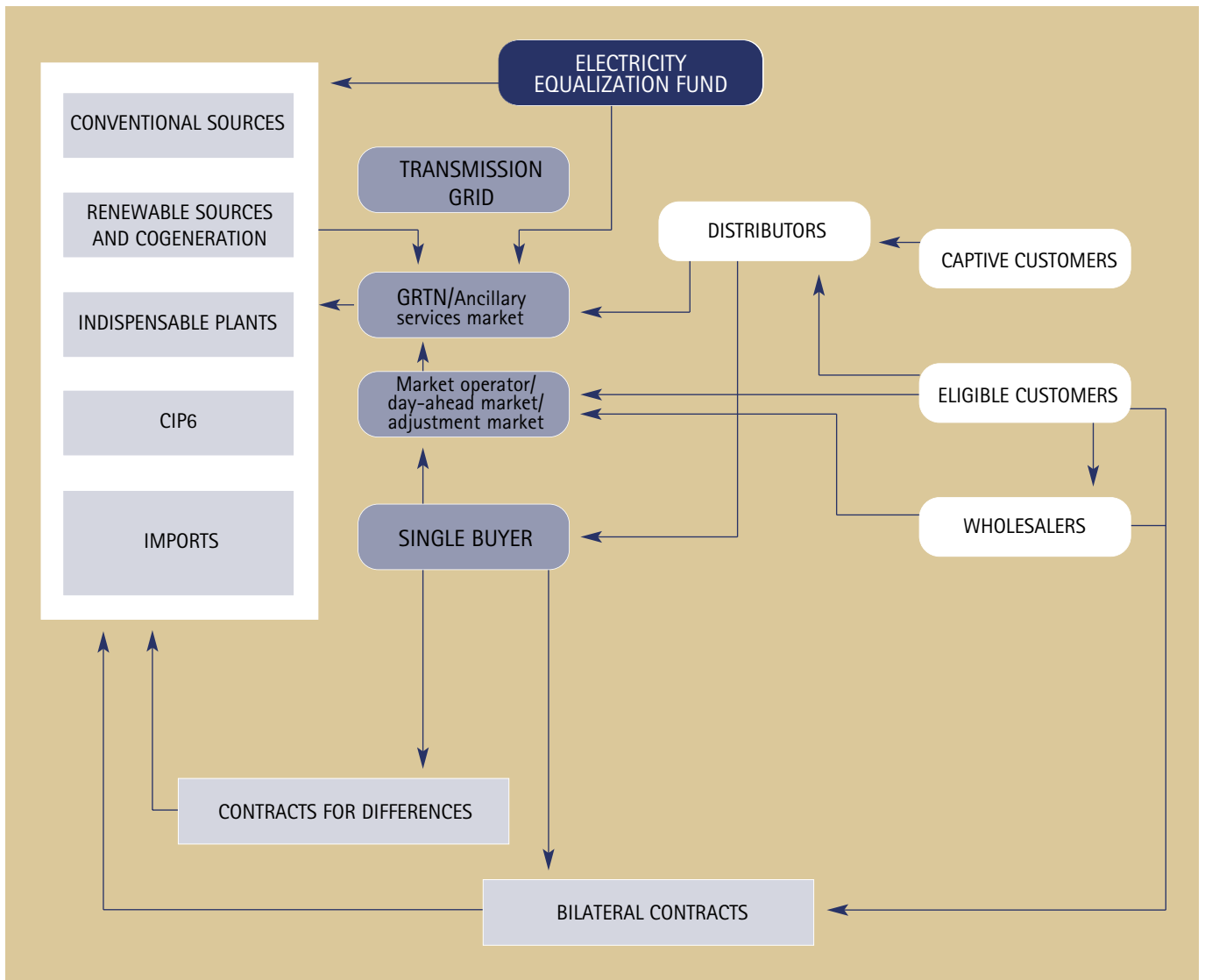
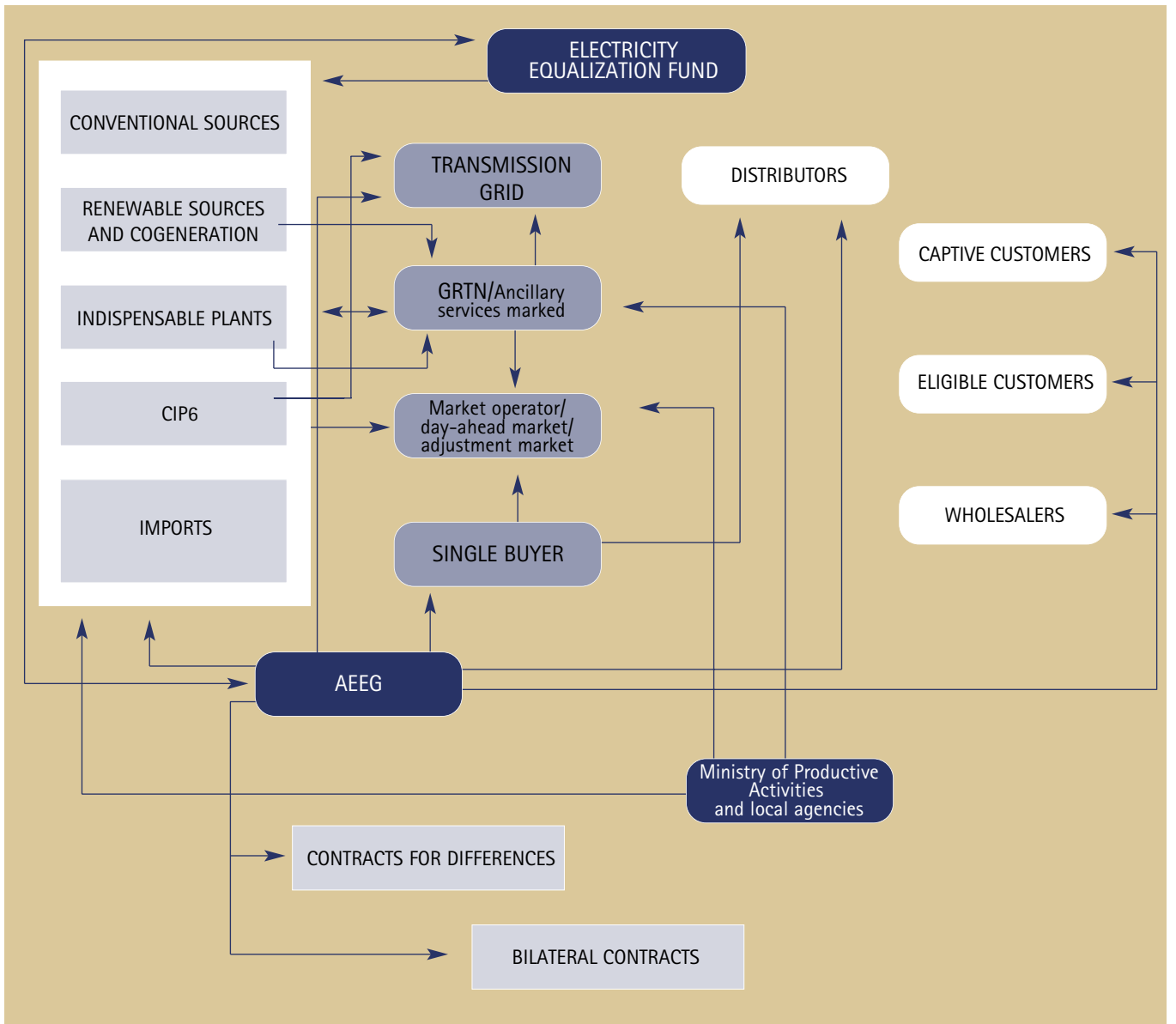


FIG. 4. FUNCTIONAL FLOWS IN THE ELECTRICITY SECTOR IN 2003



STRUCTURAL CHARACTERISTIC OF THE ELECTRICITY SUPPLY

Structure of The National Production Market

The demand for electricity rose by 2.9 percent in 2003, totalling 319 TWh. After years in which consumption growth was met thanks partly to the greater purchase of imports, national production rose by 3 percent, due in part to measures enacted in the wake of the planned outages of 26 June 2003 to ensure a safe and continuous supply of power.

For the first time since 1996, imports fell slightly (-0.1 percent), although the foreign balance still inched up (+0.7 percent) because of a decline in exports.

In terms of national output, for the second year in a row there was a significant increase in thermoelectric generation (+4.3 percent) and a further reduction in hydroelectric power (-6.4 percent), which reached its lowest point since 1990 due to the exceptionally scarce precipitation. Other renewable sources continued their steady climb, growing by 17.6 percent with respect to 2002, although absolute volumes remained modest.

In greater detail with regard to thermoelectric power, consumption was on the rise for solid fuels (+12 percent) and natural gas (+15 percent), while there was a sharp decline in the consumption of petroleum products, whose increase from 2001 to 2002 was influenced by the contingent factor of plant availability. The higher use of coal-generated power was caused by its relative inexpensiveness in 2003 and by producers' increased capacity as a result of environmental works and local agreements for the use of solid fuels. The rise in natural gas consumption stems from the implementation of new combined cycles and the increased use of these plants, which had to offset the shortfall in hydroelectric power and help satisfy the growing demand for electricity.

Seasonal patterns in consumption have changed markedly over the past few years, and in 2003 peak summer demand (53,105 MW) exceeded peak winter demand (52,590 MW) for the very first time. In December 2003, however, consumption reached a new record high of 53,400 MW. The difficulties the production system had in meeting peak demand were not caused solely by the fact that peak demand grew faster than new plants were put into service, but also by the extent of downtime (whether for shorter or longer periods) at Italian production sites.

TAB. 1 **GROSS ITALIAN ELECTRICITY PRODUCTION BY SOURCE, 1997–2003**

GWh

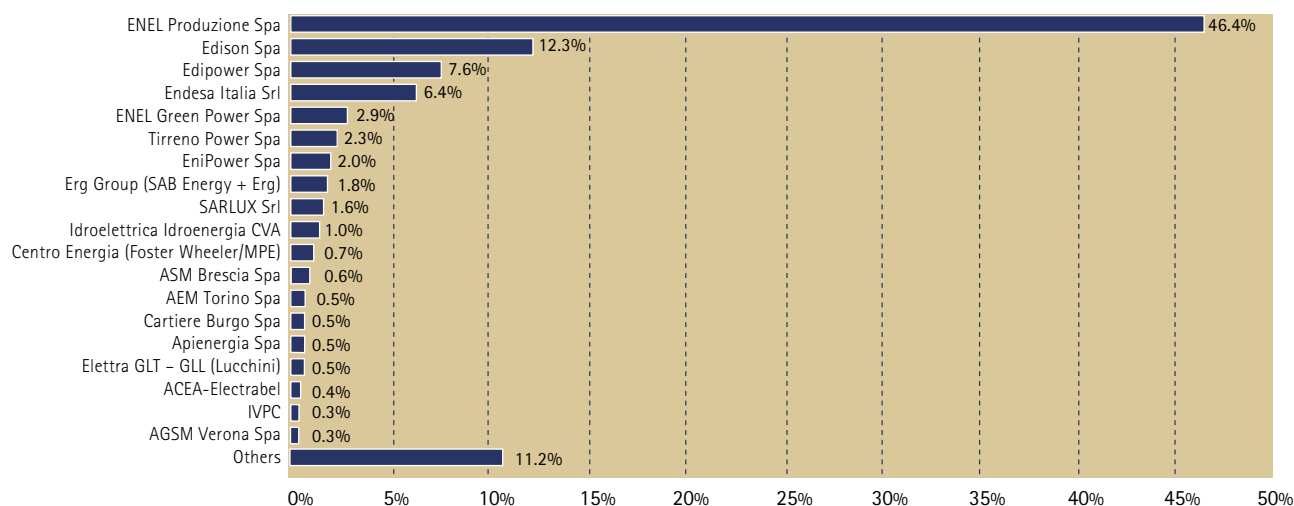
	1997	1998	1999	2000	2001	2002	2003 ^(A)
Solids	20 518	23 311	23 812	26 272	31 730	35 446	39 671
Natural gas	60 649	70 213	86 217	97 607	95 906	99 413	114 500
Petroleum products	113 282	107 237	91 286	85 878	75 009	76 997	66 579
Other	5 600	5 900	5 900	8 800	14 147	15 789	16 700
Total thermoelectric	200 049	206 661	207 215	218 557	216 792	227 645	237 450
Total pumping	4 965	6 232	6 451	6 688	7 117	7 744	7 511
Hydroelectric	41 599	41 213	45 358	44 204	46 810	39 519	36 702
Wind	118	232	402	563	1 178	1 404	1 419
Solar	6	6	6	6	5	4.1	4.1
Geothermal	3 905	4 214	4 403	4 705	4 506	4 662	5 340
Biomass and waste	820	1 228	1 822	1 906	2 587	3 422	4 400
Total renewable	46 448	46 893	51 991	51 384	55 086	49 012	47 865
Total	251 462	259 786	265 657	276 629	278 995	284 401	292 826

Source: AEEG calculations on GRTN data; for 2003, estimates on company figures.

When GRTN performed a check in accordance with the Ministry of Productive Activities directive of 26 June 2003, it found that as of June 2003, out of gross installed power of 75,755 MW only 48,047 MW were actually available, or 63.4 percent of the total.

With the completion of the ownership arrangements designated by Legislative Decree 79/99, the buyer companies have turned increasingly to repowering efforts and to the combined-cycle conversion of their plants. In 2003, conversion projects were completed for one unit at the Ostiglia plant (Endesa Italia Spa) and two units at the Sermide plant (Edipower Spa). Enel Produzione Spa reactivated two units at Priolo Gargallo, one at Pietrafitta and another at La Casella. Lastly, EniPower Spa inaugurated two new power plants in Ravenna and Ferrera Erbognone for about 900 MW of power, and AEM Milano Spa finished expanding the power station at Cassano d'Adda.

FIG. 5 MAJOR PRODUCERS' SHARE OF NET POWER GENERATION IN 2003^(A)



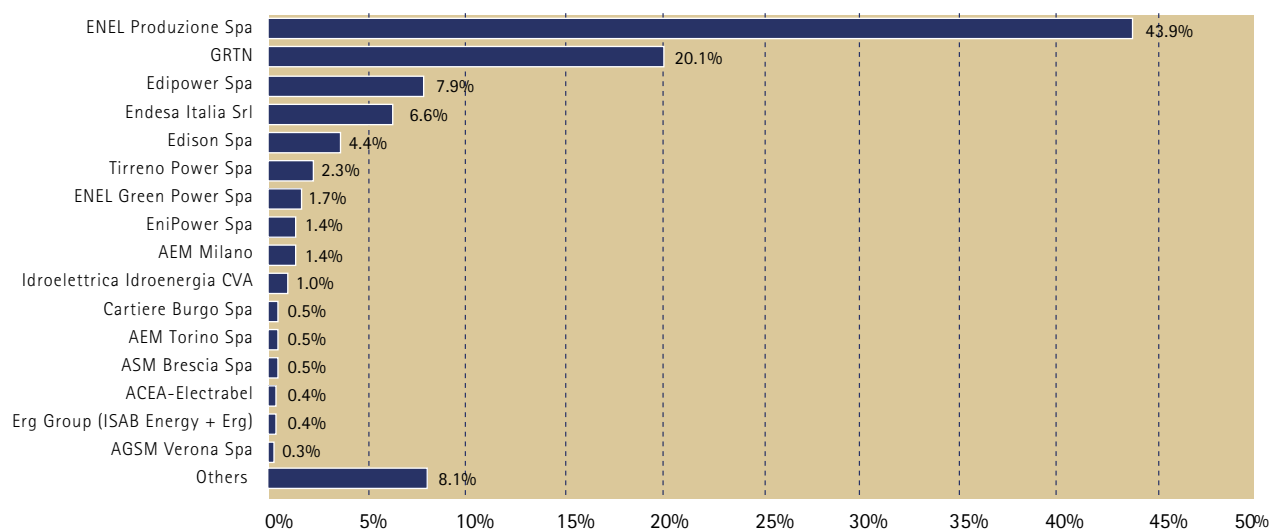
(A) Including self-production and energy withdrawn by GRTN.

Source: AEEG estimates on company figures.

Enel Produzione accounted for 46.4 percent of net national output, plus the 2.9 percent contributed by Enel Green Power Spa. The second largest producer is Edison Spa which, with its subsidiaries, generated 12.3 percent of net power. Next come Edipower (7.6 percent), Endesa Italia (6.4 percent), Tirreno Power (2.3 percent) and EniPower (2 percent). Figure 5 shows the share of net generation by the major Italian producers. The figures include any CIP6 power or other mandatory withdrawals by the transmission system operator, as well as self-production. The output of subsidiaries is combined with the total for their group.

If we exclude the power produced and paid for under CIP6 arrangements and other kinds of compulsory withdrawals by GRTN, as well as energy used for pumping, the resulting graph shows each company's share of generation destined for consumption—and differs substantially from the above. After Enel Produzione with a share of 43.9 percent, Italy's second largest supplier turns out to be the system operator (GRTN) with 20.1 percent, which is followed by Edipower (8 percent), Endesa Italia (6.6 percent), Edison and its subsidiaries (4.4 percent) and Tirreno Power (2.3 percent). In this graph as well, the figures include the utilities' self-production, if any. Unlike in Fig. 5, GRTN is treated as a supplier of electricity for consumption in relation to the volume of energy withdrawn from the various producers in accordance with Art. 3, par. 12 of Legislative Decree 79/99.

Fig. 6 MAJOR PRODUCERS' SHARE OF POWER PRODUCTION FOR CONSUMPTION IN 2003^(A)



(A) Net of energy used for pumping. GRTN is treated as a producer.

Source: AEEG estimates on company figures.

It is important to note, in any case, that during this transformation stage for Italy's power plants, a large portion of capacity is tied up in restructuring or repowering. Table 2 estimates the rate at which conversion projects reduced total installed power at Enel Produzione and the companies created through the disposal process.

TAB. 2 EFFECT OF CONVERSION WORKS IN 2003 ON INSTALLED CAPACITY

MW

	ENEL PRODUZIONE	EDIPOWER	ENDESA ITALIA	TIRRENO POWER
Installed	27 808	7 129	4 803	2 898
Unavailable	2 650	1 796	330	974
Partially available	1 335	703	768	320
Percent of total	14%	35%	23%	45%

Source: AEEG calculations on company figures

From 2002 through early 2004, the Ministry of Productive Activities authorized the construction of new thermoelectric plants for total power of 12,637 MW, as well as the conversion to coal of the Torrevaldaliga Nord plant (Enel), the combined-cycle conversion of the plants at Vado Ligure (Tirreno Power) and Tavazzano (Endesa Italia), and alterations at Brindisi Nord (Edipower) and Livorno (Enel). Permit applications were submitted for a further 45,000 MW.

The electricity sector in figures

Table 3 summarizes the role played by the main kinds of operator¹ in determining the flow of electric power, from generation and import to sale and final consumption.

The electricity sector in figures Table 3 summarizes the role played by the main kinds of operator¹ in determining the flow of electric power, from generation and import to sale and final consumption.

The 2003 figures show how generation continues to be concentrated heavily at a few electric companies: 49.4 percent for the Enel Group, 27.3 percent for the main competing groups (Edison, Edipower, Endesa Italia, Tirreno Power, EniPower); and just 4.7 percent for the municipal utilities (the main ones being AEM Milano, AEM Torino, ASM Brescia Spa, ACEA Electrabel Spa and AGSM Verona Spa). The remaining generation companies, grouped under the heading “other producers”, contributed 11.9 percent to the net generation figure. This category, made up chiefly of private firms, is highly varied; in addition to some relatively large producers (Sarlux Spa and the Erg Group, with net generation of over 4 TWh), it includes many tiny companies with a net output of less than 50 GWh. The remaining 6.6 percent of total net production was generated by self-producers, which consume most of the self-produced electricity (81 percent in 2003). Average output per company falls rapidly—approximately tenfold—from one category to the next: 138 TWh for the Enel Group, 15.2 TWh for the main competing groups, 880 GWh for municipal utilities, 220 GWh for other producers and 37 GWh for self-producers.

The differences among the various categories are also significant in terms of the power generation structure. The Enel Group uses a well-balanced array of sources. Among the main competing groups, natural gas is the primary fuel, with hydroelectric power coming in a fairly distant second. At the municipal utilities, on the other hand, hydroelectric power accounts for nearly 50 percent of net generation. The other producers obtain 53 percent of their power from petroleum products and other fossil fuels (mainly refinery products and by-products). Enel accounts for 60 percent of hydro generation (including more than 99 percent of the energy produced at pumping plants), all geothermoelectric generation, and 73 percent of coal-derived power. Generation from natural gas is more evenly distributed (Enel Group 44 percent; main competing groups 37 percent), while 75 percent of the power from renewable sources other than hydro and geothermoelectric (especially biomass and waste) is made by the “other producers” group.

The power produced under CIP6 arrangements is negligible (less than 3 percent of total net generation) for both the Enel Group and the self-producers, but it rises to over 20 percent of the total for the main competing groups and tops 80 percent for other producers. Renewable sources, however, generate 3 percent of CIP6 energy at the main competing groups, 16 percent at other producers, 90 percent at the municipal utilities, and the full 100 percent in the case of the ENEL Group.

¹ As in previous years, an operator is defined as the set of all production, sale and trading companies belonging to a single group.

TAB. 3 THE ELECTRICITY SECTOR IN FIGURES, 2003
TWh

	ENEL GROUP	MAIN COMPETING GROUPS	MUNICIPAL UTILITIES	OTHER PRODUCERS	SELF-PRODUCERS	INDEPENDENT NATIONAL WHOLESALERS	FOREIGN WHOLESALERS	WHOLESALER CONSORTIUMS	END CUSTOMERS	TOTAL
Net national output	137.8	76.2	13.2	33.3	18.4	0.0	0.0	0.0	0.0	279.0
Coal	26.0	8.8	0.4	0.0	0.6	0.0	0.0	0.0	0.0	35.7
Oil	27.6	18.1	1.0	2.0	3.8	0.0	0.0	0.0	0.0	52.5
Natural gas	48.8	40.4	4.6	8.2	7.9	0.0	0.0	0.0	0.0	109.9
Other fossil fuels	4.3	2.4	0.2	15.5	4.5	0.0	0.0	0.0	0.0	26.8
Hydroelectric	31.0	6.2	6.5	3.5	1.4	0.0	0.0	0.0	0.0	43.6
of which: pumping	7.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.4
Other renewable	0.1	0.4	0.6	4.0	0.3	0.0	0.0	0.0	0.0	10.5
of which: CIP6:										
from renewable sources	3.9	0.5	0.9	4.4	0.0	0.0	0.0	0.0	0.0	9.6
from assimilated sources	0.0	16.8	0.1	23.5	0.4	0.0	0.0	0.0	0.0	40.7
Energy for pumping	10.4	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	10.5
Foreign balance	17.6	4.3	1.6	0.6	0.0	10.3	7.9	1.7	7.0	51.0
Enel contracts	16.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.7
Assigned by GRTN	0.8	2.1	1.2	0.3	0.0	5.0	2.8	1.3	6.0	19.5
Assigned by foreign operators	0.1	2.2	0.3	0.2	0.0	5.3	5.1	0.3	1.0	14.7
Net transfers	-11.6	-10.3	-2.4	-28.8	-5.0	9.2	13.9	7.2	28.0	0.0
Of which:										
CIP6 purchases	12.6	6.6	3.9	0.2	0.0	5.5	9.9	1.6	10.6	51.0
Leakage	8.5	4.5	0.8	0.3	0.9	1.2	1.4	0.6	2.2	20.5
Total resources	124.9	65.7	11.5	4.7	12.6	18.2	20.4	8.3	32.8	299.2
End sales and consumption	124.9	65.7	11.5	4.7	12.6	18.2	20.4	8.3	32.8	299.2
Captive market	114.2	38.2	5.9	0.2	0.0	0.0	0.0	0.0	0.0	158.4
Free market	10.7	27.5	5.6	4.6	12.6	18.2	20.4	8.3	32.8	140.7
<500 MWh	0.3	0.4	0.3	0.3	0.0	1.6	0.2	0.2	0.0	3.3
500 – 5 000 MWh	1.9	7.9	1.2	1.3	0.1	5.1	2.1	2.5	0.2	22.3
5 000 – 50 000 MWh	4.4	12.6	2.2	2.2	3.6	6.2	8.9	3.2	5.8	48.9
> 50 000 MWh	4.2	6.7	2.0	0.9	8.9	5.3	9.2	2.3	26.8	66.3

Source: AEEG, on the basis of figures declared by operators and information from the eligible customer database. Net national output includes pumping. Transfers consist of energy from CIP6 plants, sales of import capacity and trading. Figures may vary with respect to other tables due to their different origin.

The foreign balance of 51 TWh stems from a substantial decline in long-term contracts held by Enel (which have now been transferred to the Single Buyer): from 22.5 TWh in 2002 to 16.7 TWh in 2003. Of the foreign balance of 34.2 TWh allocated to the free market (67 percent of the total), imports assigned by GRTN and by the foreign system operators amounted, respectively, to 19.5 and 14.7 TWh. The main beneficiaries of the imported power assigned to the free market were national independent wholesalers (30 percent of the total), followed by foreign wholesalers (23 percent) and end customers (21 percent). Wholesalers in the main competing groups acquired 13 percent of the imports for the free markets. With respect to 2002, imports by wholesalers associated with consortiums and cooperatives decreased substantially, while imports by the municipal utility wholesalers increased; together, they make up just over 9 percent of total free market allotments. About 35 percent of assignments by foreign operators went to foreign wholesalers associated with the respective export firms, although the figure rises to just under 40 percent if we include imports by companies listed in other categories that are subsidiaries or affiliates of foreign groups. Twenty-eight percent of free market allotments (9.6 TWh) was assigned under interruptible contracts.

Of total net transfers, 88 percent consisted of CIP6 energy withdrawn by GRTN and then auctioned to free-market customers, with the remainder going to the captive market. Net transfers for purchases and sales between producers and wholesalers, and within the wholesaler group, came to just over 7 TWh. The figures show a strong correlation between net outgoing transfers and CIP6 production, with the exception of the Enel Group, which in 2003 was still a recipient of the CIP6 power not auctioned to the captive market. Most net transfers of CIP6 energy and sales by wholesalers went to independently operating eligible end customers (48 percent) and to foreign wholesalers (24 percent).

If we add production to net imports and internal transfers and subtract leakage during transmission and distribution (totalling 20.2 TWh), we arrive at 299 TWh available for consumption on the final market. The figures show that end consumption on the free market does not yet amount to half of total consumption. Deliveries to the captive market by the main competing groups, through dispatch mechanisms (Team Energy Management [TEM] and subsequently STOVE), made up 24 percent of the total, compared with 72 percent for the Enel Group. We can also see an inverse correlation between group size and the incidence of sales to the free market versus the captive market: free market sales rise from less than 10 percent of the total for the Enel Group, to more than 40 percent for the main competing groups and nearly 50 percent for the municipal utilities.

End customers are major market players in terms of the energy they procure (mainly through imports and CIP6 auctions), accounting for over 23 percent of end consumption on the free market. Excluding self-procurement, the biggest suppliers of the free market are the main competing groups with nearly 20 percent of the free market, followed by foreign wholesalers (15 percent) and national independent wholesalers (13 percent). Next come self-producers for their own consumption (9 percent), while the Enel Group covers less than

8 percent of end consumption on the free market. Procurement by consortiums decreased from 11 TWh in 2002 to 8 TWh in 2003.

Forty-seven percent of free-market consumption was concentrated at large eligible customers (annual consumption above 50 GWh), of which 40 percent was self-procured. Consumption by medium-large end customers (5 to 50 GWh) made up 35 percent of end consumption on the free market; these customers were supplied primarily by the main competing groups (more than 25 percent), foreign wholesalers and national independent wholesalers. The split is similar for medium-sized end customers (0.5 to 5 GWh), whose free-market procurement was covered 58 percent by wholesalers in the main competing groups and national independent wholesalers. Lastly, about 50 percent of free-market deliveries to small customers (consuming less than 0.5 GWh per year) was assured by national independent wholesalers. The figures reveal a steep decline in the role of the main competing groups and, above all, foreign wholesalers as the volume of sales goes down. In that regard, although all categories tend to favour large and medium-large end customers, the differences between them are substantial. Less than 2 percent of the end sales of the Enel Group goes to final customers consuming under 5 GWh per year, versus 13 percent for the main competing groups and municipal utilities and 32 percent for other producers. The differences are even more striking for end customers with annual consumption of less than 500 MWh.

The last trend of note is the significant increase in the number of wholesalers (including eligible distributors), from a registered total of 229 at the end of 2002 to 349 at the close of 2003 (including 54 eligible distributors). Table 4, however, shows that more than half of the wholesalers sold no power to either end customer or other wholesalers. Judging by corresponding figures in the 2003 Annual Report, the division of the market among the main wholesalers has changed considerably over the past 12 months, although the top ranks are essentially unchanged. In any case, there appears to have been no major shift in terms of concentration. The number of wholesalers with total sales above 5 TWh increased from four to seven, but their sales as a percentage of the total rose only slightly, from 63 to 66 percent. The number of wholesalers with sales above 1 TWh rose from 18 to 32, but because of the significant increase in total volumes sold on the free market—from 105 to 148 TWh—their incidence rose by just a few percentage points, from 79 to 84 percent.

TAB. 4. **FREE-MARKET SALES BY WHOLESALERS IN 2003**

TWh

	NUMBER	SALES TO END CUSTOMERS	SALES TO OTHER WHOLESALERS	TOTAL SALES
Sales > 5 TWh	7	47.8	25.8	73.6
Enel Trade		4.6	16.2	20.8
Edison Energia		16.1	0.8	16.9
EGL Italia		9.7	0.0	9.7
NET		0.7	6.3	7.0
Enel Energia		6.1	0.9	7.0
Energia		6.6	0.0	6.6
EDF Energia		4.0	1.6	5.7
Sales of 2-5 TWh	10	18.7	11.5	30.0
Eni Power Trading		3.9	0.7	4.6
Endesa Italia Power Fuel		0.0	4.5	4.5
Dalmine Energie		3.5	0.1	3.6
Energetic Source		0.3	2.8	3.1
Electra Italia		2.6	0.0	2.7
SIET Società Intermediazione Energia Torino		1.3	1.3	2.6
Trafigura Electricity Italia		0.9	1.5	2.4
Tecnoenergia		2.2	0.2	2.4
Energia e Territorio		1.8	0.3	2.2
Telenergia		2.1	0.0	2.1
Sales of 1-2 TWh	15	10.6	10.0	20.6
Sales < 1 TWh	113	16.1	7.7	23.9
No sales	204	0.0	0.0	0.0
Total	349	93.2	55.0	148.3

Source: AEEG calculations on wholesalers' declarations. Sales to end customers do not include self-consumption and self-procurement. Sales to other wholesalers include resales.

Mandatory withdrawals as per Art. 3, par. 12 of Legislative Decree 79/99

Total power withdrawn by the system operator in accordance with Article 3, paragraph 12 of Legislative Decree 79/99 amounted to 53,882 GWh in 2003, or 19.3 percent of national production.

More than 90 percent of the electricity withdrawn by GRTN falls under the CIP6 scheme; in turn, CIP6 power can be divided into production from renewable sources (9,629 GWh, or 19 percent of the total) or "assimilated" sources (40,722 GWh or 81 percent). A further 2,395 GWh of power subject to mandatory withdrawal by GRTN comes from hydroelectric plants rated under 3 MW, as established by Resolution 62 of 18 April 2002, and a final 1,136 GWh is surplus power withdrawn according to the provisions of Resolution 108 of 28 October 1997.

TAB. 5 **WITHDRAWALS BY GR TN, 2001-2004-11-26**
GWh

	2001	2002	2003	2004 ^(A)
CIP6	47 153	49 751	50 351	50 021
of which: assimilated	38 789	41 177	40 722	40 693
of which: renewable	8 365	8 574	9 629	9 328
"Mini-hydro" (Res. 62/02)	2 769	2 899	2 395	2 389
Surplus (Res. 108/97)	3 603	1 450	1 136	843
Total withdrawals	53 525	54 100	53 882	53 315

(A) Forecasts.

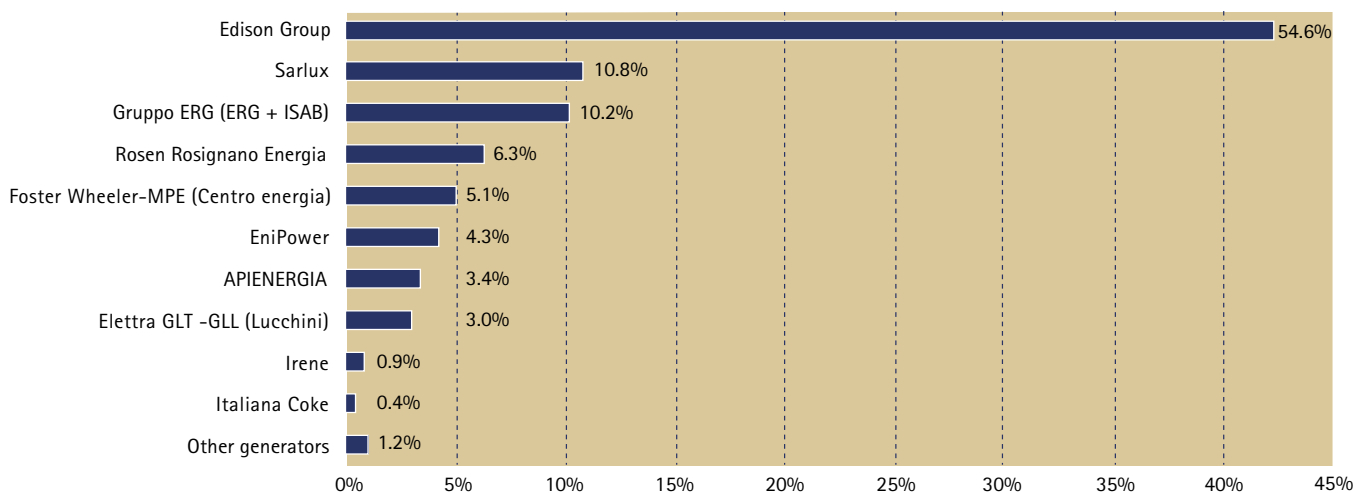
(B) Source: AEEG calculations on GRTN data.

Final figures for the past three years do not show significant changes in the volumes of CIP6 energy withdrawn. The use of surplus power has fallen steadily, on the other hand, while figures for small hydroelectric plants are influenced more by the year's rainfall than by the number of plants benefiting from the withdrawal mechanism.

Energy from "assimilated" sources made up 18 percent of national thermoelectric output in 2003. Of the 40.7 TWh produced by assimilated plants, 33.9 TWh came from new plants and was thus sold at a tariff formed by the sum of an avoided cost component and a technology incentive component; 6.7 TWh came from existing plants for which only the avoided cost component was applicable. Existing plants are those for which the eight-year subsidy period has expired but for which the withdrawal agreements with GRTN are still valid.

As shown in Figure 7, about 75 percent of CIP6 energy produced by assimilated-source plants is concentrated at five companies. The top 10 companies account for 85 percent of subsidized energy from assimilated sources.

FIG. 7 **ASSIMILATED SOURCES: GENERATION OF CIP6 POWER BY COMPANY AS PERCENTAGE OF TOTAL IN 2003 (40,723 GWh)**



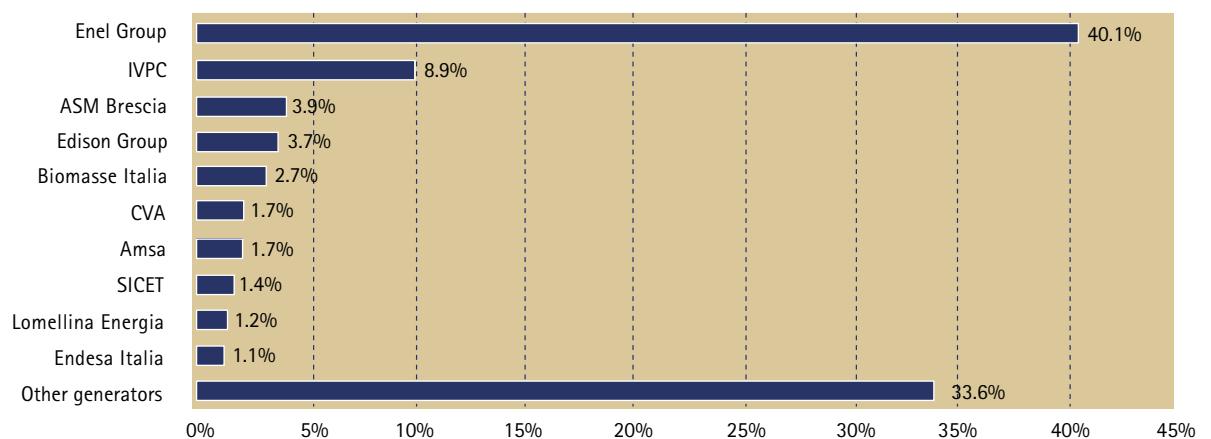
Source: AEEG calculations on company data.

Three-year figures for new renewable CIP6 plants show a distinct increase in generation. Production from biomass and MSW (municipal solid waste) plants, in particular, have seen the sharpest rise since 2001. This is the only sector that appears to have grown in 2004 as well, a sign that production by new plants is exceeding the output lost with the expiration of agreements for older ones.

Unlike energy from assimilated plants, power produced from renewable sources is more evenly distributed among producers. The top five account for roughly 55 percent of production, and the top 10 less than 65 percent. In 2003, CIP6-subsidized energy amounted to nearly 20 percent of the country's production of renewable power.

CIP6 incentives cost a total of 1,647 million for the year: 1,033 million in benefits for assimilated sources and 614 million for renewable sources. These charges belong to the A3 tariff component, with the exception of GRTN's revenues from the sale of green certificates to the parties required to hold them (an estimated 190 million). However, proceeds from the sale of green certificates to captive customers did not translate into an overall decrease in the cost of incentives for renewable energy, since companies' expense for the mandatory purchase of the certificates was offset by the introduction of the VE component into the electricity tariff (see below).

FIG. 8 RENEWABLE SOURCES: GENERATION OF CIP6 POWER BY COMPANY AS PERCENTAGE OF TOTAL IN 2003 (9,629 GWh)



Source: AEEG calculations on company data.

Table 6 shows the unit incentive cost per type of plant and the unit price at which GRTN sold power to the free and captive markets in 2003.

TAB . 6 **BREAKDOWN OF CIP6 BENEFITS BY TYPE OF PLANT IN 2003**
in euro /MWh

POWER WITH DRAWALS – REMUNERATION RECEIVED BY PLANTS	
Assimilated sources	80.58
of which: process fuels, residuals or recovered energy	98.50
of which: fossil fuels	71.54
of which: existing plants	60.07
Renewable sources	139.36
of which: reservoir and flowing water hydroelectric >3 MW	120.74
of which: flowing water hydroelectric up to 3 MW	96.00
of which: wind and geothermal	120.50
of which: solar, biomass, MSW	175.82
of which: upgraded hydroelectric	86.80
of which: existing plants	60.88
Average remuneration of energy from CIP6 plants	91.82
POWER SALES – GRTN'S REVENUES FROM SALES OF CIP6 ENERGY	
Free market	52.54
Captive market	63.12
Average sale price	55.21

Source: GRTN.

Green Certificates

The second year of renewable energy benefits based on the green certificates system came to a close on 31 March 2004. The market changed little with respect to the previous year: the demand for green certificates (i.e. the mandatory quota for power producers and importers) rose slightly, as did the supply of renewable energy from producers not included in the CIP6 subsidy scheme. The volume of green certificates not concerning CIP6 production and traded by the market operator is negligible, and prices are not yet influenced by market law and have again settled at the fixed price for certificates sold by GRTN.

To elaborate on the above, if there is a shortage of certificates from renewable-source producers, the system allows GRTN to issue green certificates for the energy produced from CIP6 plants that were opened after 1 April 1999. By covering the demand for certificates, GRTN acts as a minor market player and as such helps determine the price. GRTN certificates are sold at a fixed price amounting to the cost of CIP6 benefits for renewable-source plants net of revenues from the sale of power.

TAB. 7 COST OF GREEN CERTIFICATES INCENTIVE SYSTEM IN RELATION TO QUOTAS (2003)

	PRICE OF GREEN CERTIFICATE €/MWh	DEMAND FOR CERTIFICATES GWh	SUPPLY OF CERTIFICATES GWh	PURCHASE COST FOR THE ELECTRIC SYSTEM €/MN
GRTN	82.4	3 451	2 151	177
Renewable-source producers	75.8		1 040	79
Self-produced green certificates	29.5		260	8
Total	76.4		3 451	263

The cost of green certificates is borne first and foremost by producers and importers of conventional energy, net of the exemptions reported below. Therefore, companies with quotas to meet will incorporate the cost into their Power Exchange prices or bilateral contracts. In 2002 and 2003, because the captive market was supplied at regulated prices, it was necessary to add a new component—VE—to the electricity tariff so that companies could recover the cost of purchasing green certificates relating to production for the captive market. In those years the price charged to eligible customers included the expense of green certificates. While under the CIP6 system prices and the remuneration paid to renewable plant operators was established through an official mechanism, with green certificates the final cost is determined by the market and by the power supply strategies of the companies required to hold them.

To the direct cost of the certificates, however, we have to add the indirect costs brought about by the increased selling prices enjoyed by the categories exempt from holding them, which can be estimated as 2 percent of the certificates' price. In 2002 and 2003 these indirect costs were limited to imported energy certified as renewable (about 38 TWh), but from 2004 onwards they will also apply to national renewable energy and power from cogeneration plants.

The demand for green certificates in 2003 corresponds to the 2 percent quota applied to the amount of non-renewable energy produced and imported in 2002, net of exemptions. The increase in final demand, despite the fact that the 2 percent quota was unchanged, is the combined effect of the rise in thermoelectric output (with a simultaneous reduction in renewable-source production) and the decrease in cogeneration exemptions, due to the stricter criteria for classifying cogeneration plants that were enforced in accordance with the Authority's Resolution 42 of 19 March 2002. The reduced incidence of these two exemptions (renewable and cogeneration) was enough to offset the sharp rise in those granted to imports. The table below provides an estimate of exemptions in relation to gross domestic consumption.

TAB. 8 DEMAND FOR GREEN CERTIFICATES IN RELATION TO GROSS DOMESTIC CONSUMPTION; ESTIMATE OF EXEMPTIONS

GWh

	2001	2002
Gross domestic consumption (A+B-C)	327 372	334 998
(A) Gross production	278 995	284 401
((B) Imports	48 927	51 519
(C) Exports	549	922
Energy subject to green certificate quota	161 620	172 755
Demand for green certificates	3 232	3 455
Quota exemptions, of which:	165 752	162 243
Production services	12 354	12 935
First 100 GWh for quota-bound producers	3 400	4 200
Renewable	55 088	49 013
Imports	30 272	38 284
Thermoelectric (cogeneration and first 100 GWh)	57 523	50 069
Pumping	7 115	7 743

Source: AEEG calculations on GRTN data.

Import structure

The foreign balance for 2003 came to 50,968 GWh: the difference between imports of 51,486 and exports of 518 GWh. Imports covered 16.1 percent of the national energy requirement. For 2004, due to a decrease in import capacity caused by security measures, their volume—which already fell slightly from 2002 to 2003—will probably decline somewhat further.

In 2003–2004, the import structure changed in various ways. In quantitative terms, the interconnection capacity was reduced for security reasons, and from a qualitative point of view some changes were made to the way in which capacity is assigned to operators.

In December 2003, after a warning by GRTN, the interconnection capacity was cut from 6,400 MW to a maximum (during winter daylight hours) of 6,050 MW. For the rest of the year, as reported in Table 9, capacity was further limited to 4,250 MW. This is a temporary measure that will be effective for security reasons until the improvements agreed on by GRTN and the foreign transmission system operators are carried out.

TAB. 9 **AVAILABILITY OF IMPORT CAPACITY IN 2004**

MW

	FRANCE	SWITZERLAND	AUSTRIA	SLOVENIA	TOTAL
Winter daytime	2 650	2 800	220	380	6 050
Winter nighttime	2 450	1 600	180	320	4 550
Summer daytime	2 400	1 950	200	300	4 850
Summer nighttime	2 250	1 550	180	270	4 250

Source: GRTN.

The procedure for assigning each year's available import capacity was modified by Art. 1-quinquies, par. 5 of Legislative Decree 273 of 29 August 2003, which was converted with amendments into Law 290 of 27 October 2003. Under the new law, the responsibility for determining the means of assigning cross-border capacity no longer lies with the Authority, as it did pursuant to Art. 10, par. 2 of Legislative Decree 79/99, but with the Ministry of Productive Activities, which fulfilled that task with a decree dated 17 December 2003. In turn, Art. 2, par. 3 of the new decree states that the Authority shall take the necessary action for determining the amounts destined for the free and the captive markets, as well as the capacity reserved for interruptible customers. With Resolution 157 of 18 December 2003, the Authority completed the legal framework for the assignment of interconnection capacity.

The new regulations confirm the allocation of 2,000 MW to the captive market in accordance with long-term contracts; the power allocated to San Marino, Corsica and Vatican City; the agreements with France's Gestionnaire du Reseau de Transport de l'électricité (GRTE) concerning the joint allocation of the power available on the Italo-French border; and the 50-50 split, between GRTN and the foreign system operators, of the capacity on the other borders. The most significant change, aside from the assignment procedures discussed below, is that for a three-year period the holders of capacity subject to interruption without notice (totalling 1,750 MW) can now relinquish their import quotas against payment—1,200 MW in 2002 and 2003 and an additional 550 MW in 2004. (In 2004, interruptibility is being treated as a service to be remunerated separately and is no longer recognized solely through the preferential assignment of import capacity.)

All of the holders of instantly interruptible capacity took the chance to sell their quotas. The Authority's Resolution 151 of 12 December 2003 orders 40 percent of the 1,750 newly available MW to be allocated to the captive market and 60 percent to eligible customers. Table 10 shows the assignment of import capacity by final destination, starting with the maximum allowed power of 6,050 MW.

TAB. 10 ALLOCATION OF IMPORT CAPACITY IN 2004

MW

	FRANCE	SWITZERLAND	AUSTRIA	SLOVENIA	TOTAL
Total capacity	2 650	2 800	220	380	6 050
Long-term contracts for the captive market	1 400	600			2 000
Allocated to foreign operators		1 100	110	190	1 400
Allocated to San Marino, Corsica and Vatican City	150			150	
Allocated to interruptible customers with Resolutions 301/01 and 190/02	950			250	1 200
Allocated to interruptible customers with Resolution 157/03	550				550
Total allocable capacity for 2004	750				
Capacity made available with Resolution 151/03	1 500		250		1 750
<i>of which: allocated to the captive market (40%)</i>	700				
<i>of which: allocated to the free market (60%)</i>	1 050				
Total capacity allocated to the captive market	2 700				
Total capacity allocable to the free market	1 800				

Source: GRTN.

The capacity allocated to the free market for non-interruptible customers amounts to 1,800 MW in 2004, compared with 2,700 assigned to the captive market. However, that figure only applies to winter daylight hours; for other times of year Resolution 151/03 charges GRTN with determining the rates by which the maximum import capacity is reduced, depending on the time of year and the border. The results are reported further on in the discussion of eligible customers.

STRUCTURAL CHARACTERISTICS OF ELECTRICITY DEMAND

In the previous sections we described the structure of the national electricity supply, condensing it into three basic components: national output net of mandatory withdrawals (67 percent of the national requirement), imports (16 percent) and mandatory withdrawals pursuant to Art. 3, par. 12 of Legislative Decree 79/99 (17 percent).

We shall now discuss how supply is reconciled with demand, in relation to the free and captive markets.

TAB. 11 **SUMMARY OF ELECTRICITY DEMAND AND SUPPLY IN 2003**

GWh

	NET OUTPUT	LEAKAGE	FREE MARKET	CAPTIVE MARKET
National output for consumption ^(A)	214 290		65 618	128 114
Imports	51 486		34 786	16 700
Mandatory withdrawals (CIP6)	53 882		40 296	13 586
Total	319 658	20 558	140 700	158 400

(A) National production net of energy used for production services, pumping and exports.

Trends in the captive market

The captive market covers two kinds of customer: those whose consumption volume does not meet the eligibility threshold (100,000 MW since 29 April 2003) and eligible customers who decide to stay in the captive market. As from 1 July 2004, all non-residential customers will be eligible and thus free to choose the electric company they wish.

Power consumption by the captive market, as a percentage of total consumption, decreased by about 5 points from 2002 to 2003.

TAB. 12 **ELECTRICITY CONSUMPTION, 2001-2003**

	2001		2002		2003	
	GWh	% OF TOTAL MARKET	GWh	% OF TOTAL MARKET	GWh	% OF TOTAL MARKET
Captive market	187 183	65.6	170 543	58.6	158 400	53.0
Free market	75 995	26.6	98 224	33.8	119 700	40.0
Self-consumption	22 314	7.8	22 193	7.6	21 000	7.0
Total market	285 492	100	290 960	100	299 100	100

Source: GRTN for 2001 and 2002; AEEG calculations on company data for 2003.

For 2002, GRTN has produced statistics on customer mobility, in terms of switching from the captive to the free market as well as supplier switching within the latter. That year about 13,000 customers (measured as withdrawal points from the grid) switched from the captive to the free market for a total of 21,800 GWh, or 7.5 percent of the entire market, while around 3,000 customers changed electric company within the free market for a total of 18,200 GWh or 6.3 percent of the market.

When the eligibility threshold was lowered to 100,000 kWh per year on 29 April 2003, the number of eligible customers rose to 144,000, with overall consumption of 191,000 GWh in 2002. Figures for calendar year 2003 show that eligible customers continued to fill about 20 percent of their power requirement on the captive market, as explained in greater detail below.

The number of eligible customers will come to around 5 million when the market is fully opened to non-residential demand, starting on 1 July 2004. Consumption by captive customers who will become eligible on that date can be estimated at 95,000 GWh. If all eligible customers migrate to the free market, the captive market will therefore amount to roughly 63,000 GWh. Whether it will be less costly for small and medium sized businesses to switch from the captive to the free market will depend largely on the difference between the two tariffs, since the cost of seeking and choosing a new supplier should not be particularly high with respect to the potential savings.

Trends in the free market

Sale of power to eligible customers

In 2003 the size of the eligible customers market did not change much after 29 April, when the eligibility threshold was reduced to 100 MWh, in terms of either the number of consumption sites or the amount of power consumed. The number of eligible customers rose by barely 4,000 and their consumption by 4.3 TWh.

The increase—amounting to less than 3 percent—is explained chiefly by the granting of eligibility to self-producers, whose withdrawals are below the threshold, and withdrawal points whose consumption exceeds 100,000 kWh only if combined into networks, aggregated loads, etc. and which were thus not required to be informed of their eligibility status by distributors in accordance with Resolution 20 of 13 March 2003. In addition to these are the new (or pre-existing) sites that were able to demonstrate that they reached the threshold on the basis of monthly consumption in 2003. For these customers, an immediate, on-line self-certification procedure made it easier to achieve recognized status.

In total, there are 257,992 electricity withdrawal points associated with eligible sites, with an average of 1.75 withdrawal points per site. Lazio is the region with the most withdrawal points per site (six); end customers in that region include some of the largest consumption sites in the country. Examples are Consorzio Energia Gruppo Telecom Italia Spa, Poste Italiane Spa, BNL Banca Nazionale del Lavoro Spa, Radio Dimensione Suono Spa and Wind Telecomunicazioni Spa, which have withdrawal points throughout Italy but whose sites are located in Lazio by convention because their registered office or main withdrawal point is there.

At the regional level, the greatest percentage growth in the number of sites since the threshold was lowered, as a result of self-certification by eligible customers, took place in the Valle d'Aosta (+55.6 percent) and in Umbria (+13.8 percent), while the smallest increases occurred in Sardinia and Sicily (respectively +0.4 and +0.7 percent).

As shown in Table 13, consumption by eligible customers who purchased power on both

the free and captive markets came to 195.5 TWh for the 12 months from April 2003 to April 2004, of which 177.7 TWh was withdrawn from the grid. Average consumption per site was 1.3 GWh, essentially unchanged with respect to the previous 12-month period. The energy produced and consumed by self-producers came to 9 percent of total consumption by eligible end customers, a decrease of 1.7 TWh on the previous year. For the calendar year 1 January–31 December 2003, there were about 145,000 eligible sites, for a total of 249,000 withdrawal points and 176.2 TWh withdrawn from the grid².

² The difference with respect to the 177.7 TWh reported as of 30 April is due to eligible customers recognized after 31 December 2003.

TAB. 13 EVOLUTION OF THE FREE MARKET, 2003-2004

	APRIL 2003 ^(A)			APRIL 2004		
	NO. SITES	CONSUMPTION (TWh)	CONSUMPTION PER SITE (GWh)	NO. SITES	CONSUMPTION (TWh)	CONSUMPTION PER SITE (GWh)
By region						
Valle d'Aosta	239	0.4	1.7	372	0.6	1.6
Piedmont	11 688	19.1	1.6	11 966	19.9	1.7
Lombardy	34 245	45.9	1.3	35 066	46.3	1.3
Liguria	3 033	3.5	1.1	3 107	3.5	1.1
Veneto	15 976	20.0	1.3	16 568	19.4	1.2
Trentino Alto Adige	3 558	3.6	1.0	3 666	3.8	1.0
Friuli Venezia Giulia	3 810	7.1	1.9	3 944	7.0	1.8
Emilia Romagna	14 390	17.8	1.2	14 955	18.1	1.2
Tuscany	10 301	11.0	1.1	10 555	11.2	1.1
Marches	4 498	4.0	0.9	4 679	4.0	0.8
Umbria	1 277	3.8	2.9	1 453	3.9	2.7
Lazio	8 926	9.3	1.0	9 119	10.8	1.2
Abruzzo	2 612	4.1	1.6	2 719	5.6	2.1
Molise	517	0.9	1.7	526	0.9	1.6
Campania	7 397	9.1	1.2	7 502	8.8	1.2
Puglia	6 449	7.3	1.1	6 567	7.6	1.2
Basilicata	1 056	1.5	1.4	1 067	1.5	1.4
Calabria	2 751	1.5	0.5	2 798	1.5	0.5
Sicily	7 787	12.4	1.6	7 817	12.0	1.5
Sardinia	3 306	8.7	2.6	3 328	8.7	2.6
By range of consumption (GWh)						
0.1 - 0.2	67 590	9.5	0.1	69 550	9.6	0.1
0.2 - 0.5	40 474	12.6	0.3	41 756	12.9	0.3
0.5 - 1.0	14 966	10.6	0.7	16 140	11.3	0.7
1.0 - 2.0	10 105	13.4	1.3	9 448	13.1	1.4
2.0 - 5.0	6 296	19.5	3.1	6 418	19.7	3.1
5.0 - 10.0	2 276	15.8	6.9	2 326	16.0	6.9
10.0 - 20.0	1 115	15.5	13.9	1 152	16.0	13.9
20.0 - 50.0	597	18.1	30.3	589	17.8	30.3
50.0 - 100.0	208	14.3	69.0	209	14.5	69.6
> 100.0	189	61.9	327.4	186	64.1	344.7
Total	143 816	191.1	1.3	147 774	195.1	1.32

(A) As of 29 April 2003, the date the threshold was lowered. In Table 4.13 of the 2003 Annual Report it corresponds to "May 2003".

Source: eligible customer database.

Since May 2003, with the eligibility threshold significantly lowered, the groupings that were once allowed to access to the free market in order to help open it up (corporations, groups, national multi-site businesses, consortiums and cooperatives for the purchase of electric power) are no longer recognized. However, consortiums and cooperatives continue to play an important role in amassing demand, especially in the small and medium-size business sector, as shown by a rough analysis of the data submitted in accordance with the mandatory notification procedure required by Resolution 20/03. According to the figures at hand, about 43 TWh was withdrawn by these groupings in calendar year 2003.

At the end of 2003 there were over 15,000 grouped consumption sites: about 11 percent of the total eligible market, versus 77 percent just before the threshold was lowered to 100,000 KWh. The average withdrawal per site was 2.7 GWh, considerably higher than the average withdrawal per eligible site (1.3 GWh), demonstrating a tendency to favour the grouping of larger sites which presumably implies lower running costs for the same amount of energy purchased. Conversely, it would appear from informal contacts with operators that smaller sites procuring power on the free market have turned to trade associations or consultants for support.

THE MARKET

The Power Exchange

The opening of the Power Exchange in our country is a fundamental step in the process of liberalizing the electricity sector as outlined in Legislative Decree 79/99.

According to Art. 5, par. 2 of that decree, the Power Exchange was supposed to be up and running on 1 January 2001. In truth, it was not until 2003—and more extensively in 2004—that it was possible to inaugurate a merit order dispatch system, which is still in transitional form.

The rules of trade for production plants have changed radically in the new framework. Until now, on the basis of the old dispatch system, GRTN scheduled each unit's production so as to meet projected demand while ensuring a real-time reserve and balancing service. The system operator did its best to have these services provided at minimal cost, and the power companies were paid on the basis of parameters defined by the Authority, each one pertaining to an individual phase of the service. The CT component, for example, covered the cost of fuel, while PGf offset fixed costs.

When the Power Exchange reaches full swing, the prices and quantities of electricity and ancillary services (procurement of resources for managing congestion, reserves and balancing) will be determined by the law of supply and demand. Therefore, production will not be scheduled by GRTN but on the exchange itself, where sale and purchase offers are collected for every hour of the following day. The new dispatch system is called "merit order" because sale and purchase offers are arranged in ascending and descending order, respectively, allowing the system to satisfy consumers' demand at the minimum cost asked of the producers.

In Italy, the Power Exchange has been divided into three separate markets: the day-ahead market, the adjustment market and the ancillary services market.

The day-ahead market (organized and run by the market operator) is held on the morning of the day prior to when the electricity is actually bought and sold. The participants are producers, eligible customers and the Single Buyer, who submit their price and quantity offers for each hour of the following day.

On the adjustment market (also organized and run by GME), which takes place once the day-ahead market has closed, operators can change the schedules they have arranged as a consequence of the day-ahead market by submitting new buy and sell offers. The reason why the adjustment market is necessary is that the outcomes of the day-ahead market may not be compatible with the optimal functioning of the production units, so once the day-ahead results are known they can be corrected.

The ancillary services market (organized and run by GRTN) serves to inform GRTN whether operators are able (in terms of quantity and price) to increase or decrease the power injected or withdrawn at every hour. GRTN uses this flexibility to correct the trades established on the GME-run markets in case of conflicts with grid limitations, and to procure reserves for real-time balancing of the system.

Also, as provided for by Legislative Decree 79/99, power can be traded through bilateral contracts in which prices and quantities are defined by the parties. To make sure the quantities traded under these contracts are synchronized with the needs of the grid, operators report their injection and withdrawal schedules to GRTN, which notifies GME, which enters them into the day-ahead market at a price of nil.

In addition to the Power Exchange and the use of bilateral contracts, there are two other important ways of procuring electricity:

- mandatory withdrawals by GRTN (mostly of CIP6 power), in accordance with Art. 3, par. 12 of Legislative Decree 79/99;
- imports.

Eventually, both producers and consumers will be allowed to trade on all three markets, but the current Sistema Italia 2004 design is still a transitional system to which only producers are admitted. Demand is still defined by GRTN on the basis of forecasts.

The market is being implemented in various stages. In July 2003 the Sistema transitorio di offerte di vendita di energia elettrica (STOVE) system took effect, according to the structure defined in Resolution 67 of 26 June 2003. Meanwhile, the roundtable set up by the Ministry of Productive Activities proposed a transitional market called Sistema Italia 2004, whose phases were outlined in the ministry's report of 11 December 2003. According to the report:

- an experimental trading phase would begin on 8 January 2004, in parallel with STOVE.

With Resolution 163 of 23 December 2003, STOVE was extended to the full month of January 2004, and some changes were made to the system;

- starting on 1 February 2004, a transitional market to replace STOVE would be inaugurated without demand-side participation. This was postponed by two months, however, at the request of GRTN and GME;
- the switch to the full-fledged market was supposed to take place on 1 April 2004, but, in view of the second phase, with Resolution 168 of 30 December 2003 the Authority defined rules for the energy dispatch service and for resource procurement on the basis of economic merit, making sure the rules reflected the Sistema Italia 2004 experience. Earlier, with a decree dated 19 December 2003, the Ministry of Productive Activities had approved the consolidated electricity market act.

With Resolution 48 of 27 March, the Authority ordered the start of merit order dispatch as from 1 April and established rules reflecting the needs arising out of Sistema Italia 2004 without the active participation of demand, to remain effective for the rest of 2004 only. When merit order dispatching was implemented, the bidding system described in Art. 5, par. 1 of Legislative Decree 79/99 also took effect.

Electricity dispatch

Rules for the dispatch service (Resolution 168/03)

With Resolution 168/03 the Authority established the rules for the public electricity dispatch service in Italy and for the procurement of the necessary resources on the basis of economic merit, pursuant to Arts. 3 and 5 of Legislative Decree 79/99. The purpose of the resolution was to complete the regulatory framework for the physical execution of electricity trades made on or off the Power Exchange. In other words, with Resolution 168/03 the Authority:

- a) defined the rights to use transmission capacity once electricity is purchased;
- b) identified resources and fees for the dispatch service.

As far as point a) is concerned, in a monopolistic system the production unit is selected at the same time as the power is dispatched, while with merit order dispatch the system has to be made compatible with the grid's transmission capacity. It is therefore a good idea to arrange for the allocation of capacity utilization rights for the energy traded on the day-ahead, adjustment and ancillary services markets. Those rights are assigned by GME on behalf of GRTN upon acceptance of buy and sell orders, which are selected on the basis of economic merit. Bilateral contracts, as mentioned above, are included in the day-ahead market as GME enters them at a price of zero when notified by GRTN. For the allocation of transmission capacity, a dispatch hierarchy is established to ensure that offers are fulfilled in

the following order: units essential to system security as identified by GRTN; unschedulable and schedulable renewables; cogeneration plants; CIP6 plants; units fed exclusively by national sources of primary fuel energy; bilateral contracts; and other offers.

As for point b), as explained above with regard to the three markets making up the Power Exchange, the ancillary services market is used by GRTN to handle congestion, reserves, and the proper balancing of injections and withdrawals for the real-time management of the electric system. On the ancillary services market, participating operators must make all of their production units' power available to GRTN.

Production units whose technical characteristics make them unsuited to providing these resources must pay a fee to GRTN to make up for the unrendered service. The amount will be established later, at the suggestion of GRTN, which also identifies and recompenses the units that are essential for system security and defines and publishes the unavailability of production capacity and transmission networks.

Capacity payment

Legislative Decree 379 of 19 December 2003 introduces new rules for the remuneration of electricity production capacity. Its purpose, especially in light of the blackouts of June and September 2003, is to guarantee adequate production capacity and reserves in order to satisfy national demand.

The decree institutes a competitive benefits system designed to influence the conduct of power producers and (where appropriate) end customers with the proper technical characteristics, and to ensure that capacity is available on the days GRTN deems critical.

The "capacity payment" system will be defined by the Ministry of Productive Activities and by a follow-up decree drawn up according to GRTN's recommendations, with the input of the Authority. Until then, the Authority will be introducing a temporary remuneration system for plants that make their capacity available on the days of the year that GRTN reports are crucial with respect to meeting demand. The benefits do not apply to CIP6 plants, unschedulable renewables, and power committed to the fulfilment of bilateral contracts.

The transitional capacity payment system was launched by the Authority with Resolution 48/04.

More specifically, to reduce consumers' expense to a minimum and make the measure compatible with the remuneration systems for electricity and reserves that will take effect along with merit order dispatch, the Authority decided to devise a capacity payment mechanism consisting of two separate components:

- the specific fee paid to plants in exchange for their availability on critical days of the year. The amount differs according to the time of year and time of day. GRTN has identified highly critical days—working days from 7 June to 10 September, excluding August, and from 6 to 23 December—and ordinary critical days, i.e. the rest of the year

except for mid-August and the periods from 8 March to 8 May and from 27 September to 29 October;

- an additional fee, defined as supplementary income on the revenues earned by the producer on the Power Exchange markets (excluding the ancillary services market) if, over the course of a year, those revenues are less than hourly output times the higher of the Power Exchange price and the official price of electricity (PG_n) reduced by 20 percent.

The expenses arising from the capacity payment system, in its temporary form, will be covered through the “CD” tariff component.

Supervision of the electricity market

Article 5 of the Trade Ministry decree of 19 December 2003, issued upon approval of the consolidated electricity market act, asked the Authority to establish the following:

- a mechanism for keeping market power in check;
- procedures for monitoring price trends on the electricity market;
- the criteria according to which the market operator would create electricity price indices and GRTN would set up the ancillary services market.

To meet this obligation, the Authority published a consultation document called “Measures for promoting competition and efficiency in the supply of electric power pursuant to Art. 1, par. 1 of Law 481 of 14 November 1995”. The document recommended methods of monitoring the trades that take place within and outside the bidding system, and of tracking changes in the structure of the electricity market. The monitoring system would be based in part on a number of market indices defined by GME and GRTN in accordance with the general criteria set by the Authority. The indices were meant to provide concise information on three aspects: market structure, trading results, and operators’ conduct on the markets. With regard to limiting market power, the consultation document offered two different measures: a transitional one, based on quantity checks and the use of bid caps; and a permanent one, based on the obligation for operators with a certain share of the market to enter into contracts for differences with the Single Buyer at a price regulated by the Authority.

Based on the comments received through the consultation process, with Resolution 21 of 24 February 2004 the Authority changed the proposals in the original document as follows:

- because of the arbitrary nature of estimating marginal costs, the Authority abandoned

the idea of a “competitive index” meant to simulate the hypothetical equilibrium of a competitive market, which would have been used to evaluate the degree of competition on the Italian electricity market;

- to simplify the transitional system, a new method of calculating minimum quantities was introduced, replacing GME’s simulation with a formula that calculates minimum quantities in relation to load, the operator’s market share and the market share of its competitors;
- to avoid the problems posed by the differentiated bid cap and address some of the operators’ concerns about covering peak unit fixed costs, a single bid cap was introduced in the amount of 500/MWh;
- to give all operators an equal opportunity to take out contracts for differences with the Single Buyer, operators with market shares of over 20 percent were no longer required to cover price and quantity risk, while the Single Buyer was obliged to purchase this coverage through a bidding system for at least 30 percent of the energy requirement of the captive market net of long-term import contracts and CIP6 production.

Lastly, with Resolution 49 of 27 March 2004, the Authority ordered:

- the Single Buyer to take out new contracts for differences with selected parties, through discriminatory reverse auctions, with a starting price 2 percent higher than at auctions held in accordance with Resolution 21/04 (because of the outcome of those earlier auctions, the Single Buyer had to take out new contracts for differences in order to provide better protection from price risk for captive market customers);
- new definitions of the market indices introduced with Resolution 21/04;
- a more precise definition of the quantity control mechanism to make it more appropriate to actual supply conditions in the national electricity market, and to form a correlation with the contracts for differences taken out by the Single Buyer.

Procurement options for the free market: imports and CIP6

Allocation of import capacity to eligible customers

The procedure for assigning each year’s available import capacity was modified by Art. 1-quinquies, par. 5 of Legislative Decree 273 of 29 August 2003, which was converted with amendments into Law 290/03. Under the new law, the responsibility for determining the means of assigning cross-border capacity no longer lies with the Authority, as it did pursuant to Art. 10, par. 2 of Legislative Decree 79/99, but with the Ministry of Productive Activities, which fulfilled that task with a decree dated 17 December 2003. In turn, Art. 2, par. 3 of the new decree states that the Authority shall take the necessary action for determining the amounts destined for the free and the captive markets, as well as the capacity reserved for interruptible customers. With Resolution 157 of 18 December 2003, the Authority completed the legal framework for the assignment of interconnection capacity.

The new regulations confirm the allocation of 2,000 MW to the captive market in accordance with long-term contracts; the power allocated to San Marino, Corsica and Vatican City; the agreements with France's Gestionnaire du Reseau de Transport de l'électricité (GRTE) concerning the joint allocation of the power available on the Italo-French border; and the 50-50 split, between GRTN and the foreign system operators, of the capacity on the other borders.

Allocation of CIP6 power to eligible customers

For 2004, the regulatory material for the new CIP6 allocation procedures consists of a Ministry of Productive Activities decree of 29 January 2004 and Attachment A of the Authority's Resolution 13 of 6 February 2004. The changes are designed to bring the means of allocating CIP6 production capacity better into line with the evolution of the electricity market and with considerations of system security.

With respect to 2003, interruptible-with-notice customers and customers with at least 55 percent of consumption in F4 hours are no longer granted priority access. As for the capacity available to interruptible-with-notice customers, in accordance with the rules for the allocation of import capacity, that service was separated for the sake of guaranteeing a secure CIP6 allocation system and so that it could be remunerated regardless of the means of procurement. With Resolution 151/03 the Authority established a fee of 8/MWh for the service.

In light of the Council of State's decision 1605/03 concerning the division of available power between the captive and eligible market, 20 percent of CIP6 capacity (880 MW on an annual basis) was allocated to the Single Buyer to supply the captive market, and 3,520 MW was assigned to eligible customers in general.

Power is no longer allocated via auction, but on a pro-quota basis, according to the procedures laid down in Resolution 13/04. Pro-quota allocation means that with a given capacity of 3,520 MW, once eligible customers submit their capacity requests, GRTN reduces them in proportion to the ratio of total requests to available power.

The minimum allocation is 1 MW, and no single operator may take up more than 10 percent of available capacity. The allocable power cannot exceed the average power withdrawn in 2003, net of the assignment of import capacity and including any capacity foregone in connection with interruptibility.

TAB. 14 ALLOCATION OF CIP6 CAPACITY IN 2003 AND 2004

MW

	2003	2004
Available capacity for the year	4 400 ^(A)	4 400 ^(A)
To eligible customers without interruptibility restrictions	3 000	3 520
To interruptible-with-notice eligible customers	1 000	-
To eligible customers with >55% consumption in F4 hours	400	-
To the Single Buyer for supplying the captive market	-	880

(A) Additional capacity made available in 2003 and 2004 was assigned to the captive market.

In 2003, the final price of CIP6 energy was determined by two components: the starting price at auction, which was correlated with fixed generation costs (24.3/MWh) and could be raised by bidders, and a component indexed to the variable Ct. In 2004, under the pro-quota system, the fixed-cost component remained at 25/kWh, but starting in July the variable component will be indexed both to Ct and the average Power Exchange price.

Three categories of eligible customer took part in the allocations for 2003: those whose loads can be interrupted with notice (to whom 1,000 MW was reserved), those with at least 55 percent of their consumption in F4 hours (400 MW), and eligible customers with no interruptibility restrictions (the remaining 3,000 MW).

Table 15 shows final allocation figures in 2003.

TAB 15 CIP6 ALLOCATIONS IN 2003: QUANTITIES AND AVERAGE PRICES PER TYPE OF USER

	GWh	€-cent/kWh
Energy sold to the free market	40 296	52.54
Energy sold to the captive market	13 586	63.12
Total	53 882	55.21

REGULATED ACTIVITIES

New regulatory period

Organization of the electricity sector and tariff regulation

Over the past five years the electricity sector has undergone major organizational changes, fuelled by the process of deverticalization and unbundling that Italy is experiencing including in accordance with EU directives. The tariff regulation system proposed by the Author-

ity for the period 2004–2007, in keeping with the previous regulatory period, is based on a vertical organization of activities and is designed to foster competition at every stage of the process that is not conducted on a monopoly basis in accordance with current laws. The main activities constituting the electricity sector and the areas of tariff intervention are described below.

The production of electric power is a free enterprise, although certain obligations apply due to its nature as a public service. For the years prior to 2003, when the bidding system (Power Exchange) had not yet been implemented, it was up to the Authority to set the wholesale price of electricity for customers in the captive market. Since the advent of the bidding system, the price received by power producers—whether the energy is consumed by free- or captive-market customers—is established by market principles or in bilateral negotiations. Electricity transmission and dispatch activities are reserved to the state, which delegates them to the transmission system operator (GRTN). Since these are conducted on an exclusive basis, they need to be regulated to ensure non-discriminatory access to the network infrastructures; incentives for boosting efficiency have to be in place and prices have to be set in relation to costs. These objectives, especially the efficiency incentives, cannot be pursued without regard for the infrastructures' organizational and ownership structure. For the new regulatory period, fee structures will take account of the planned reunification of infrastructure ownership and management.

In the previous regulatory period, the transmission business was remunerated in the context of tariff options for transport (which included transmission and distribution). Under the new system, there is a specific, regulated tariff for transmission. As for the coverage of dispatch costs, separate analyses have to be made for dispatching itself and for procurement of the necessary resources. Costs for the dispatch service pertain to GRTN. In the previous regulatory period, they were covered by officially defined tariff components that were included under transport tariffs; for the new period, they form part of the sale tariff for customers in the captive market. For free-market customers, on the other hand, there is a specific tariff component. Since the Power Exchange has been operating, resources for the dispatch service have been procured on the basis of both market mechanisms (congestion relief, management of secondary and tertiary reserves, balancing) whose point of reference is the ancillary services market—an integral part of the Power Exchange—and non-market systems (primary reserve, voltage regulation, black start service). In any case, for captive end customers there are tariff devices that allow signals generated upstream to be transferred downstream in an appropriate manner.

Distribution is an exclusive activity conducted on the basis of concessions from the Ministry of Productive Activities. The concession-granting procedure has highlighted the purpose of this activity, namely:

- management of the distribution network
- maintenance decisions

- design and planning of development projects
- plant operation
- execution of maintenance work
- realization of development projects.

As we saw for transmission and dispatch, the monopolistic nature of the distribution business (in the current legal framework) requires regulatory efforts to ensure equal access to the networks and tariff regulation mechanisms that will encourage efficiency and guarantee prices reflecting actual business costs. For the new regulatory period, the previous system based on tariff options arranged by the distributor has been effectively confirmed.

The sale of electricity is a free enterprise. However, because the rights of captive-market customers need protection and tariffs have to be uniform throughout the country, the Authority still needs to regulate prices for the sale of power to the captive market. Under the rules in force for the new regulatory period, captive customers—as part of the tariff—cover the electricity procurement cost incurred by the Single Buyer, which has acted as guarantor of the power supply for these customers since 1 January 2004. That cost, which is thus transferred to the end customers, is estimated on the basis of the price at which power is sold to distributors and of the various means by which the Single Buyer procures it (Power Exchange, bilateral contracts, contracts for differences, imports and CIP6). The tariffs include remuneration for the marketing of the vending service which, since the previous regulatory period, has been separated from that of the distribution service.

Electricity metering, while potentially a free enterprise, requires tariff regulation mechanisms in consideration of the current organizational and regulatory set-up. Only when metering is opened to competition can this form of intervention be gradually removed.

During the first regulatory period, which ended at the close of January 2004, costs for performing the metering service were not covered through a separate tariff component but by revenues from the transport service. For the new period, a specific component has been added to cover that cost.

The new consolidated act on tariffs

With Attachment A to Resolution 5 of 30 January 2004, the Authority defined the regulation of fees for the transmission, distribution, metering and sale of electricity to customers in the captive market for the period 1 February 2004–31 December 2007.

The process that led to the new consolidated act was conducted in parallel with the procedure to regulate the quality of distribution, metering and sale services for 2004–2007, which was initiated with Resolution 31 of 1 April 2003. The Authority's decisions regarding fees for transmission, distribution, metering and sales were taken in light of the quality improvement objectives it established in Resolution 4 of 30 January 2004.

Tariff-regulated services during the first and seconde regulatory periods

The tariff system in force during the first regulatory period was based on three public services, each divided into activities:

- the transport service, which included:
 - power transmission
 - dispatch, remunerated as a separate service
 - power distribution
- the vending service, broken down into:
 - the sale of electricity to the captive market
 - the sale of electricity to distributors for sale to the captive market
 - dispatch to the captive market, remunerated only as reimbursement of the costs incurred for procuring resources, prior to the start of merit order dispatch
- the metering service.

For the second regulatory period, the Authority streamlined the rules and identified the following as public services subject to tariff regulation under the new consolidated act:

- power transmission
- power distribution
- the purchase and sale of electricity for the captive market, split into:
 - the sale of electricity to the captive market by the Single Buyer
 - the sale of electricity to the captive market by distribution companies
- metering, broken down into:
 - meter installation and maintenance
 - meter reading and recording.

The new consolidated act establishes fees for each of the services in question. Unlike in the first regulatory period, the following are identified separately:

- the fee covering the cost of the metering service
- the fee covering the cost of marketing power to the captive market.

Allowed costs

For the purpose of setting initial regulated tariffs for February 2004, the Authority has calculated the allowed cost for each service by combining the cost information found in:

- the operators' individual annual accounts, drawn up in accordance with Resolution 61 of 11 May 1999 (as amended)
- the replies to questionnaires that the Authority designed and sent to all operators for compilation.

The allowed cost includes the following:

- operating costs (mainly for external resources, including personnel and the purchase of materials and services)

- depreciation of fixed assets
- a fair return on capital.

Recognized operating costs for 2004 were defined as the sum of:

- operating costs reported in 2001, carried forward to 2004
- utilities' share (50 percent) of excess productivity gains.

The return on invested capital, in real terms gross of taxes, was set at 6.7 percent for the transmission service, 6.8 percent for the distribution service and 8.4 percent for metering and for the purchase and sale of electricity for customers in the captive market.

For the transmission and distribution services, which are not open to competition, the Authority has established an opening tariff that is adjusted annually according to a price cap mechanism, which is applied to the components covering operating costs and depreciation. The tariff component that covers the return on invested capital is adjusted by means of an annual review by the Authority, which revalues fixed assets and considers the net investments carried out during the previous year.

The planned productivity gain ("X factor") has been set at 3.5 percent for distribution and 2.5 percent for transmission.

For electricity metering, purchase and sale, activities that will be gradually opened to competition, there are no automatic annual adjustments. The fees set by the Authority will be adjusted year by year on the basis of the actual development of competition in the individual areas of the market.

Hook-up charges and fixed fees, which are both subject to price caps, have been reduced by 3.7 percent.

The tariff structure in effect for regulatory period 2000–2003 ensured that non-residential customers would cover allowed costs for transport on the distribution and transmission networks, metering, and the vending service that were not covered by hook-up charges, in the form of transport service fees. The V1 cap, which for each type of contract (other than low-voltage residential use) placed a ceiling on the annual tariff revenues that a company could earn from the transport service, included revenues meant to cover the cost of service continuity improvements.

Tariff structure for end customers

The tariff structure for regulatory period 2004–2007 consists of the following, for each kind of contract other than low-voltage residential use:

- regulated tariffs covering the cost of the transmission service
- tariff options for the distribution service
- regulated tariffs covering the cost of the metering service
- regulated tariffs covering the cost of the vending service.

Costs for service continuity improvements are covered by a specific component (UC6) that is not included in V1.

For residential customers, the structure of the reference tariff (D1) has changed very little with respect to the first regulatory period, although there are now specific tariff components for the coverage of metering and marketing costs.

Until the special rate is introduced for low-income households, during the second regulatory period the reference tariff will continue to be D1. End customers will be charged D2 or D3, or they may choose optional residential rates if proposed by the distributor.

Equalization mechanisms

The new consolidated act also institutes:

- a general equalization system
- a specific, by-company equalization system.

The general system applies to all distributors, except electric companies eligible for tariff integration in accordance with Art. 7 of Law 10 of 9 January 1991 (“small power companies”).

The equalization of distribution costs and other expenses borne by distributors for the period 2004–2007 can be broken down as follows:

- equalization of the cost of procuring electricity for customers in the captive market
- equalization of transmission service costs
- equalization of the cost of distributing power over high-voltage grids
- equalization of distribution service costs as they pertain to the transformation of high-voltage to medium-voltage power
- equalization of the cost of distributing power over medium- and low-voltage grids
- equalization of revenues from the supply of electricity to residential customers.

The specific company system applies to distribution costs only and is meant to balance differences between actual distribution costs and allowed revenues that cannot be captured through statistical and econometric analysis (and are thus not equalized under the general system) and that are in any case beyond the company’s control. The company system will be developed on the basis of enquiries aimed at determining the real distribution costs of each individual business.

Time bands

The new consolidated act on tariffs introduced a time band structure that reflects the changed electricity consumption habits of Italian households. The new bands, based on GRTN’s best estimate of the state of the electric system in 2004, equate peak hours with summertime and the month of December and high-load hours with the rest of the winter. To allow for the reprogramming of meters, Resolution 5/04 extended the validity of the 2003 time bands until 1 April 2004.

Transmission

Transmission service for end customers

During the first regulatory period, allowed costs for transmission were covered as part of the fees for the transport service. In the new period, each distributor charges its end customers a specific tariff component pertaining to transmission, which varies according to whether the end customer has a meter designed to report consumption in each of the time bands (F1, F2, F3 and F4).

The yearly adjustment of the transmission service component is performed separately for the portion covering operating costs (including depreciation) and for the remaining portion that represents the return on allowed invested capital.

A price cap of 65 percent is in effect for the portion covering operating costs. Every year, the Authority adjusts it on the basis of:

- the average change over the previous 12 months in consumer prices for blue- and white-collar households, as gauged by the National Statistical Office (ISTAT)
- the annual reduction on allowed unit costs (2.5 percent)
- the increase or decrease associated with changes in allowed costs due to unforeseeable extraordinary events, new legislation and changes in universal service obligations
- the change associated with the cost of conservation-based methods of controlling demand.

The portion meant to remunerate allowed invested capital (35 percent of the total), to which the price cap does not apply, is adjusted annually to take account of:

- the average change in the deflator of gross fixed investment, as reported by ISTAT, for the last four quarters available in relation to ISTAT's publication schedule
- the expected change in the demand for electricity in Italy
- the change associated with realized net investment
- the change associated with the extra remuneration allowed for the development of transport capacity.

The absolute necessity of improving the capacity and efficiency of transport over the national power grid, especially in consideration of the blackouts that occurred in 2003, has highlighted the need for measures that will encourage investments in grid development. This is why projects to improve the national transmission grid that are approved by the Ministry of Productive Activities and completed by 30 June of the year prior to that for which the tariffs are valid will be remunerated at a higher rate. Therefore, for these investments, when the Authority conducts its annual review of tariffs it will apply a remuneration rate 2 points higher than the general rate applied to the transmission service.

Transmission service for distributors and producers

GRTN charges distributors a specific fee for the power withdrawn from the national grid and from high-voltage virtual interconnection points (where a production plant connects to the distribution network). The distributors pay this fee directly to the producers if the producers have medium- or low-voltage virtual interconnections to the national transmission grid.

Fees are also due if one distributor performs transmission and distribution services for another, along the lines of the rules in effect for the first regulatory period.

The fee paid by production plants to GRTN for the energy produced and injected has not changed since 2003.

The new consolidated act also sets the fee covering GRTN's allowed operational costs. The amount has been determined in order to guarantee revenue in 2004 that will cover all investments relating to the security plan for the reduction of power outage risk (an estimated 12 million for the year).

The transmission service fee for distributors and producers is adjusted each year according to the same criteria used for the transmission-cost component of the tariff paid by end customers.

Unification of grid management and ownership

The Prime Minister's Decree of 11 May 2004 defines the criteria, procedures and conditions for unifying the ownership and management of the national power transmission grid as per Art. 1 ter, par. 1 of Decree Law 239/03. The aims of the process are to improve the efficiency, security and reliability of the Italian electric system and to pave the way for the privatization of the national grid. By 31 October 2005, GRTN will transfer all of its activities, functions, assets, liabilities and other legal relationships to Terna Spa against due compensation. To foster the development of transport capacity on the grid and encourage a more secure, less costly electric system, the company produced by the unification will be subject to specific operational rules. The rules are based on the principles of impartiality and neutrality and are designed to protect all parties from discrimination. Specifically, a limit has been set on share ownership. No producer, importer, transmitter, distributor or vendor of electric power will be able to exercise voting rights exceeding 5 percent of Terna's capital in the election of its Board of Directors, including through subsidiaries or parent or sister companies. When the national grid is privatized, a stable core of one or more reference shareholders will be created. This should guarantee protection of the new company's role as a public utility.

Today, less than 10 percent of the grid is owned by public and private parties. To improve its security and efficiency, the unification of the national transmission network will be completed by the new company Terna Spa.

Interruptibility compensation

As mentioned in the section on procurement options for the free market, interruptibility is no longer connected with the allocation of import capacity and of GRTN power withdrawals. Interruptibility now falls fully under the category of regulated ancillary services, and has been formalized in contracts for a three-year period.

The availability of interruptible-without-notice power required by GRTN—1,750 MW—has been purchased in the form of interruptible eligible customers' import allocations for 21 per MWh. The interruptible-with-notice requirement of an additional 1,750 MW is assured by 94 operators at a price of 8 per MWh.

The interruptibility service will be remunerated through the "INT" component, which for the free market is collected by GRTN together with the fee for managing the dispatch service, and for the captive market is part of the sale tariff, pursuant to Resolution 46 of 27 March 2004.

Procurement of dispatch services

Transitional dispatch (Resolution 27/03)

The rules for the transitional dispatch service, introduced by Resolution 36 of 7 March 2002, were postponed and modified with Resolution 27 of 1 April 2003 following a public consultation process, in order to solve some problems operators encountered with the first set of rules.

The main changes brought about by Resolution 27/03 are as follows:

- the validity of electricity transport contracts depends on the conclusion of balancing and exchange agreements; grid access contracts are in the name of one party only, and wholesalers who serve end customers for the conclusion of electricity balancing and exchange agreements must also enter into transport agreements; all withdrawal points available to a single legal entity within the catchment area of a distribution company are grouped into a single contract;
- power withdrawal schedules for withdrawal points with hourly meters must be treated on an hourly basis only with respect to end customers who were eligible when Resolution 27/03 took effect; power injection schedules for production plants with hourly meters are treated on an hourly basis, with the exception of plants with a nominal rating of less than 10 MVA;
- the fee for the balancing and exchange services is paid on an advance basis, subject to equalization on the basis of checks by GRTN; GRTN settles the transactions underlying the advance-basis settlement through an equalization procedure within a period of 12 months;
- electricity trades are settled on a quarterly basis; the preliminary balances for each quarter and every trade can be negotiated freely between the users of the exchange

service and deducted from the amount due to GRTN, in order to reduce total exposure before GRTN issues its advance-basis settlement figures; the preliminary balances are carried forward to subsequent quarters less a 3 percent reduction;

- component VE is paid on the basis of the total balance of the free market, if negative, by means of an average fee paid by the holders of electricity exchange contracts that have contributed to that negative balance.

The commencement of merit order dispatch was postponed for all of 2003 and the first quarter of 2004.

Transitional system for the sale of electric power (Resolution 67/03)

With Resolution 67/03 the Authority also established, for the second half of 2003, a transitional bidding system applicable to the procurement of resources covering the needs of the captive market and resources for dispatch, including the availability of production capacity for the reserve power supply.

A new system for supplying the captive market was needed in order to overcome the problems of the Team Energy Management (TEM) procedure, which had proved to hamper competition.

The TEM procedure, adopted in connection with the production capacity disposal process pursuant to Art. 8 of Legislative Decree 79/99, was instituted with a view to providing a temporary procurement mechanism and was meant to be replaced by the start-up of the Power Exchange. TEM applied solely to the former Enel plants (i.e. the facilities of Enel Produzione, Enel Green Power and the three “Gencos”), and was based on an agreement lacking in transparency.

However, the conclusion of the disposal of Enel’s plants and the resulting tensions that this produced as to how plants would be selected to supply the captive market and the dispatch service, as well as the desire of the Ministry of Productive Activities to send a signal of progress toward a competitive market, clashed with the sector’s true regulatory and operational conditions. The Authority intervened in June 2003, with a consultation document in which it proposed a Sistema transitorio di offerte di vendita di energia elettrica (STOVE), to take effect from the second half of 2003. Although STOVE maintained the operational processes and methods of calculation in use under the TEM procedure organized by ENEL, it aimed to achieve a sufficient degree of transparency and competition among the various parties in the procurement of resources covering about half of Italy’s total demand for electric power. Under STOVE, the dispatch mechanisms were basically unchanged and plants were remunerated in relation to the wholesale market price established by the Authority. In parallel, an Energy Roundtable was set up at the Ministry of Productive Activities—made up of representatives from the major power institutions—to outline a model for a Power Exchange that could rapidly become reality.

STOVE was in effect until 31 March 2004, when Sistema Italia 2004 (Italy’s Power Exchange) opened for business.

The Single Buyer

With a decree dated 30 December 2003, the Ministry of Productive Activities made the Single Buyer—in place of Enel—the guarantor of the supply of electricity to the captive market. This means that the Single Buyer is responsible for procuring power on behalf of distribution firms. It has several possibilities for doing so. Table 16 provides an estimate, as of 1 May, of the volumes the Single Buyer will have procured for the period April-December 2004 and the pricing systems in force. It shows that the Single Buyer has entered into contracts of various kinds (CIP6, imports, bilateral agreements, contracts for differences) for the procurement of 61.2 percent of its estimated total energy, and is expected to procure the remaining 38.8 percent on the Power Exchange with the full related risk unhedged.

TAB. 16 PROCUREMENT BY THE SINGLE BUYER IN 2004

SOURCE	QUANTITY	ESTIMATED GWh (APRIL-DECEMBER 2004)	% OF TOTAL PROCUREMENT	PRICE
CIP6 allocations	Single Buyer to have access to 20% of available CIP6 capacity (4 400 MW), amounting to 880 MW	5 809	4.6%	67.9% of CT +2.5 €-cents/kWh as estimated fixed generation costs. From 1 July, Power Exchange prices also figure in the calculation
CIP6 occasional capacity	The electricity produced by CIP6 plants not included in the constant annual figure of 4,400 MW is sold to the Single Buyer	3 141	2.5%	Same terms as for annual CIP6 capacity
Long-term import contracts	2 000 MW	3 171	2.5%	Wholesale price
Imports 2004	700 MW reassigned following surrender of interruptibility	11 442	9.1%	Price negotiated with importer
Bilateral contracts	Up to 25% of forecast demand	31 680	25.1%	Must be lower than wholesale price
Power Exchange	The remaining quantity to satisfy captive market demand	71 091	56.3%	Power Exchange price
of which: contracts for differences		22 038	17.4%	Discriminatory reverse auctions with base price = wholesale price (subsequently, under Resolution 49/04, with base price = wholesale price + 2%)
Total		126 334	100%	

Distribution

Local distribution monopoly (completion of the process of selling off distribution networks)

In 2003 and early 2004, the process of streamlining power distribution continued as provided for in Art. 9 of Legislative Decree 79/99. In October, the Ministry Decree of 28 December 1995 that had ordered the transfer of the distribution business to Enel Distribuzione Spa was confirmed, and the convention with the Ministry of Productive Activities was adapted to the legislation issued since it was drafted. Also, Enel Distribuzione continued to sell off portions of its network for an approximate total of 118,000 customers.

TAB. 17 PORTIONS OF THE NETWORK SOLD BY ENEL DISTRIBUZIONE AS OF 1 MARCH 2004

BUYER	LOCATION	NO. MUNICIPALITIES COVERED BY SALE	CONTRACT SIGNED	EFFECTIVE DATE
A.M.E.A.	Paliano (FR)	1	29/8/2003	1/9/2003
AIM	Vicenza	1	30/5/2003	1/6/2003
AMG	Gorizia	1	28/2/2003	1/3/2003
ASM Brescia	Brescia	46	30/12/2003	31/12/2003
ASM Terni	Terni	1	29/12/2003	31/12/2003
ASM Voghera	Voghera (PV)	1	26/2/2004	1/3/2004

Source: Authority's calculations on Enel Distribuzione figures.

Enel Distribuzione itself acquired the portion of the distribution network held by A.M.E.A. of Pergine Valsugana (for a total of five municipalities), and took over the entire distribution business of AEC - Comune di Castelnuovo Val di Cecina for a total of 1,433 customers.

Regulation of distribution tariffs

For the distribution service, the system of tariff options is more or less unchanged. Each distributor presents at least one basic option, along with special options, to all of the customers in its catchment area other than low-voltage residential users.

Price cap V1, established in connection with the new tariff option TV1, defines for each kind of contract a limit on the tariff revenues that the company can earn in any given year from providing the distribution service. Price cap V2, which relates to tariff option TV2, sets for each kind of contract the maximum distribution tariff that can be charged to the customer.

Tariff TV1 covers allowed costs for distribution over high-, medium- and low-voltage grids and for the marketing of the distribution service. As defined by the new consolidated act, therefore, TV1 differs from the tariff in effect during the first regulatory period because it sets a cap on the revenues distributors can earn for the distribution service only, while

allowed costs for transmission, metering and sales are no longer capped but subject to separate regulated tariffs.

Every distributor also charges its end customers (free and captive alike) additional tariff components that cover the following:

- imbalances in the systems of equalizing transmission and distribution costs and integration mechanisms (component UC₃);
- allowed costs stemming from improvements in service continuity (component UC₆).

Simplified tariffs

Distribution companies whose networks include fewer than 5,000 withdrawal points (as of 31 December 2003) can opt for a simplified tariff system that exempts them from the duty to propose basic distribution tariff options and from the V1 price cap. In place of the tariff options, these companies charge their customers tariff TV2 and, if they deem it appropriate, the tariff components for withdrawals of reactive energy set by the Authority with Resolution 23 of 4 March 2004. Companies that opt for the simplified tariff system do not take part in mechanisms for the equalization of distribution costs.

Regulation of the distribution business during the transitional period

For the transitional period (1 February–30 June 2004), distributors have the possibility to propose changes to or request the suspension of tariff options, since the revenues they earn during the period will be counted towards the actual income to be compared against that allowed by price cap V1 as defined for 2004. The Authority has also formulated methods of calculating allowed income and actual income which, for 2004, differ in part from the provisions of the new consolidated act. This was necessary to take account of the transitional application of the 2003 options (which cover not only distribution, but also transmission and metering) and of the consequent suspension of the specific transmission and metering components, which are no longer subject to the price cap according to the rules of the new regulatory period.

Companies presented their new tariff options by the deadline of 30 April 2004, using, as they had in the past, a computerized system for registering options and submitting them to the Authority on-line. The options approved by the Authority will be offered and applied to customers between 1 July and 31 December 2004.

Metering

The electricity market cannot run and its services cannot be performed without the hourly measurement of consumption. The new consolidated act defines the rights and obligations of those responsible for the metering service, which is broken down into meter installation and maintenance and meter reading and recording.

The Authority has studied input from the major distributors as to the quantity of hourly meters currently installed (grouped by level of available power and nominal voltage of the withdrawal point) and projected installations in coming years. On that basis, it has ordered the installation of new hourly meters for extra-high-, high-, and medium-voltage withdrawal points according to a timetable reflecting available power.

Hourly meters will not have to be installed at low-voltage points because the electricity withdrawals by these customers will be treated as per the load profiling established by the Authority with Resolution 118/03. As for the remuneration of the metering service:

- end customers pay the distributor a specific tariff covering meter installation and maintenance and meter reading and recording;
- the owners of production units pay 54 percent of the metering tariff to the operator of the network with which the production unit is connected, as compensation for the meter reading and recording service;
- at interconnection points between networks, the company that installs and maintains the meter is entitled to 46 percent of the metering tariff;
- at interconnection points between networks, the company that performs the meter reading and recording service is entitled to 54 percent of the metering tariff.

Sale to captive customers

Pricing for the captive market

Under the new consolidated act, the final price paid by each customer in the captive market includes a tariff component that covers the cost of procuring electric power. That component has been changed since the previous regulatory period to take account of the new means by which distributors procure electricity and of its different pricing structure.

The tariff component covers the purchase of electricity for the captive market, dispatch costs, and the expenses deriving from the application of the rules on green certificates until the commencement of merit order dispatch.

During the first regulatory period the variable cost of purchasing electricity for the captive market was adjusted at the start of every quarter (starting in January 2003, before which it was adjusted at the beginning of every two-month period) on the basis of the preceding trend in international fuel prices. In the new regulatory period, the entire purchase cost is updated quarterly according to an advance estimate for the subsequent cycle.

As in the first period, the tariff is unique for customers without meters equipped to record consumption in different time bands, and differentiated by time of use for other customers. Also, while distributors are unable to offer alternatives to the standard tariff component, for customers with meters that can record consumption in time bands FB1 and FB2—as per Section II.1 of CIP 45/90—a two-tier tariff was introduced with effect from 1 July 2004 that distinguishes between daytime use and consumption at night or on Sundays and holidays. The electricity tariff for customers in the captive market also includes a component for

commercial costs. In addition, there is component UC₁ (which funds the account for the equalization of captive market electricity procurement costs), currently set at zero, and component UC₅, which covers expenses for the compensation of leakage.

As during the first regulatory period, captive-market residential customers receive extra price protection in the form of obligatory tariffs—D1, D2 and D3—set by the Authority. D1 is the reference tariff and represents distributors' allowed cost for the supply of power to residential customers. Until the preferential system for economically disadvantaged households (the low-income tariff) is defined, D1 is not being charged to end customers. The tariffs currently in effect are as follows:

- D2, for power used at the customer's legal residence where power ratings are 3 kW or less;
- D3, charged to residential customers whenever D2 does not apply.

The Authority publishes the components making up the tariff for captive-market customers at the beginning of every quarter, on the basis of the Single Buyer's estimate of its unit procurement costs for each of the next four quarters.

Because of the delay in the commencement of merit order dispatch, the STOVE system as per Resolution 67/03 is still in effect for both the procurement of electricity for the captive market and the resources required for dispatch. As such, transitional measures were needed for the sale of power to captive-market customers in 2004. Resolution 5/04 established specific amounts for the components covering captive-market electricity procurement for the period from 1 February to 31 March 2004.

New time bands (Resolution 20/04)

Resolution 5/04 extended the 2003 time bands through March of the following year, so that operators could adjust meters to the new schedule. It also established the price at which the Single Buyer could sell power to distributors, from 1 February 2004 until the commencement of merit order dispatch (no later than 31 March 2004). These measures were based on the assumption that the Power Exchange would be up and running in early February. Indeed, the coexistence of the 2003 time bands for the first quarter of 2004 and the bands to take effect as from the second quarter of the year, in accordance with the consolidated act, was consistent with the determination of the price for electricity sales from the Single Buyer to distributors, which was set according to the rules of the first regulatory period for the month of January only and according to the new rules (for 2004–2007) from February onwards. Because the delayed start of the Power Exchange forced an extension of the transitional period, the mixed tariff system for 2004 would have been especially costly for end customers, who would have had to pay peak winter rates according to the old time bands and peak summer rates on the basis of the new ones—which effectively shifted peak hours from winter to summer.

Therefore, the Authority's Resolution 20 of 19 February 2004, which applied to the period March–May 2004, modified the Single Buyer-to-distributor price of power in order to bring the total average tariff back into line with what it would have been had the old wholesale

price been applied to the new time bands starting in January 2004.

The adjustment for the month of March was made so that the price of electricity, obtained by charging the new prices on the 2003 time bands, was the same as it would have been applying the prices to the 2004 time bands. In addition, the prices thus attained were reduced to take account of the higher pricing for January and February. As it turned out, the start-up of the Power Exchange on 1 April 2004 meant that the resolution affected only the month of March.

Resolution 20/04 was contested by some producers, and the Regional Court of Lombardy ordered its retraction. On 30 April, the Authority filed an appeal against the order with the Council of State, which rejected it on 7 May.

**Remuneration of
production capacity and
interruptibility
(Resolution 46/04)**

With Resolution 46/04, the Authority had to institute new fees to be included in the tariff component covering the cost of power procurement for the captive market. These serve as:

- remuneration of the capacity made available by producers on days the GRTN deems critical for satisfying estimated demand, in accordance with Legislative Decree 379/03;
- compensation for with- and without-notice interruptibility, as per Resolution 151/03, following instructions from the Ministry of Productive Activities in a note dated 5 December 2003 (Prot. 4241) and from the undersecretary of state for energy with a note dated 11 December 2003 (Prot. 628);
- coverage for GRTN's expense of complying with the provisions of Resolution 1 of 22 January 2004, concerning the reconciliation of electricity supplied to the free market in 2001.

Resolution 48/04 extended to all free-market customers the obligation to pay these fees to GRTN.

**Fees for the transfer of
power to distributors for
sale to the captive market**

The Trade Ministry decree of 19 December 2003 established the Single Buyer as the only supplier of electricity to eligible customers who choose, for the time being, to remain in the captive market. It also outlined the principles by which the new consolidated act regulated sales between the Single Buyer and distributors of the power to be supplied to the captive market, with an emphasis on:

- the terms of sale (a standard contract will be drawn up and approved by the Authority, governing the terms of business between distributors and the Single Buyer);
- the distributors' procurement cost for the sale of power to the captive market. The sale price is determined so as to reflect the costs incurred by the Single Buyer for the purchase of electricity and to compensate for the services rendered thereby;
- billing and payment terms, according to a timetable of payments by the distributor to the Single Buyer that allows the latter to remain financially viable. The sale price, calculated by the Single Buyer during the month following the transaction, is billed monthly to each distributor on the basis of the power destined for the captive market.

In consideration of the vicarious role still being played by Enel, with Resolution 5/04 the Authority set up transitional measures for the sale of power to distributors. Until the commencement of merit order dispatch, distributors will continue to buy from Enel the electricity for the captive market that they are unable to produce with their own plants, at an officially established price.

ELECTRICITY PRICES AND TARIFFS

Trend in ISTAT Consumer price index

After dipping in early 2002, in May of that year the price of electric power for Italian households started to rise again due to worsening conditions in the international oil and crudes market. The price reached in July was stable through the rest of the year, by virtue of the tariff freeze instituted by the Italian Cabinet with Decree Law 193 of 4 September 2002 (converted into Law 238 of 28 October 2002).

At the start of 2003, the price index³ returned to early 2001 levels and reached a high during the second quarter of the year. This trend is due largely to the heightening of tension on the international fuel markets in late 2002 and the first quarter of 2003. By April, the index had risen 5.7 percent on the previous year, but the growth slowed in subsequent months and stopped altogether during the final quarter of 2003. For the year, the increase was 2.8 percent, slightly greater than inflation; in real terms the price of electricity for households rose by a modest 0.3 percent after dropping sharply (-3.9 percent) the previous year.

³ In the context of the national basket of consumer prices for the entire population, ISTAT reports the price of electricity each month as part of the “household expenses” category.

TAB. 18 **MONTHLY ELECTRICITY PRICE INDEX**

Index (1995 = 100) and percent change

MONTH	2002				2003			
	NOMINAL PRICE	% CHANGE 2002-2001	REAL PRICE (A)	% CHANGE 2002-2001	NOMINAL PRICE	% CHANGE 2003-2002	REAL PRICE (A)	% CHANGE 2003-2002
January	98.1	-4.9	83.6	-7.1	103.3	5.3	85.7	2.4
February	98.1	-4.9	83.2	-7.3	103.3	5.3	85.5	2.8
March	98.0	-5.2	83.1	-7.5	103.3	5.4	85.2	2.6
April	98.0	-5.2	82.8	-7.5	103.6	5.7	85.3	3.1
May	99.0	-1.3	83.4	-3.6	103.6	4.6	85.1	2.1
June	99.0	-1.3	83.4	-3.4	103.6	4.6	85.1	2.0
July	101.3	0.8	85.2	-1.5	102.6	1.3	84.1	-1.3
August	101.3	0.8	85.1	-1.7	102.6	1.3	83.9	-1.4
September	101.3	0.8	84.9	-1.7	102.6	1.3	83.8	-1.4
October	101.3	0.8	84.7	-1.8	101.2	-0.1	82.5	-2.5
November	101.3	0.9	84.4	-1.9	101.2	-0.1	82.3	-2.5
December	101.3	0.9	84.3	-1.9	101.2	-0.1	82.3	-2.5
Average for the year	99.8	-1.5	84.0	-3.9	102.7	2.8	84.2	0.3

(A) Electricity price index as percentage of the general index (excluding tobacco products).

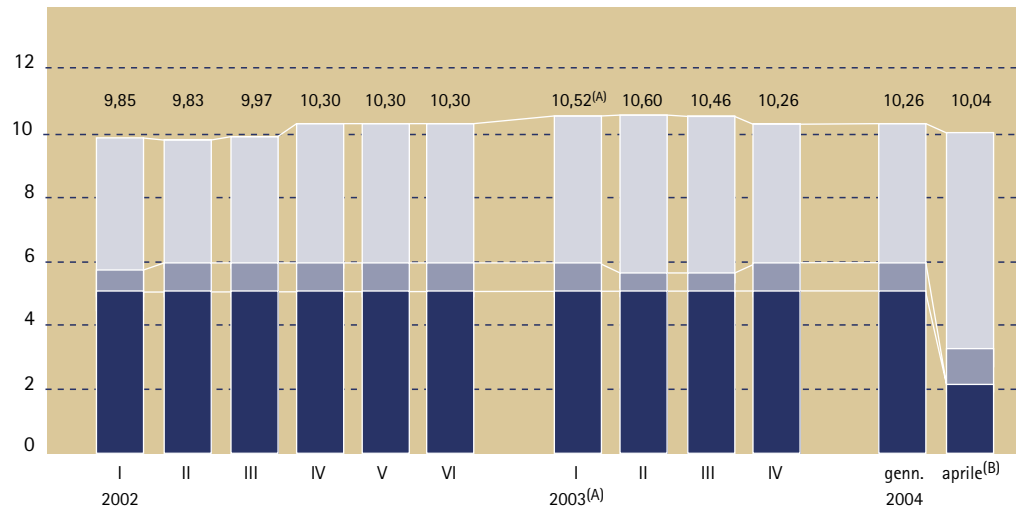
Source: Calculations on ISTAT data, national indices for entire population.

Breakdown by component of the national average electricity tariff

The trend for electricity in the ISTAT index of consumer prices is confirmed in the pattern set by the national average electricity tariff net of taxes, as calculated by the Authority. The sharp increase in July/August 2002 with respect to May/June of that year (3.3 percent) was followed by a stable period mandated by the government's tariff freeze. In early 2003, the tariff rose by over 2 percent compared with the second half of 2002, although the potential increase was softened by the new indexing system devised by the Authority in November 2002. Under the new system, tariffs began to be adjusted quarterly as opposed to every two months, on the basis of average international prices for the previous six (rather than four) months, and the no-change threshold was raised from 2 to 3 percent. The tariff started to fall again in the second quarter of 2003, reaching late-2002 levels by the end of the year.

FIG. 9 BREAKDOWN OF NATIONAL AVERAGE ELECTRICITY TARIFF, NET OF TAXES, FOR THE PAST TWO YEARS

Eurocents per kWh



- COMPONENT COVERING FUEL COSTS
- COMPONENT COVERING GENERAL SYSTEM COSTS
- COMPONENT COVERING FIXED GENERATION EXPENSES AND COSTS FOR TRANSMISSION, DISTRIBUTION, METERING AND VENDING

(A) From the first quarter of 2003 the cost of fuel includes the expense of green certificates.

(B) Since the start-up of the Power Exchange, fixed generation costs have been included in the Single Buyer's procurement costs and cannot be reported separately from the cost of fuel.

For January 2004, in view of the imminent publication of the consolidated act for the transmission, distribution, metering and vending of electric power for regulatory period 2004–2007, the Authority confirmed the tariff in effect during the final quarter of 2003. For February/March it set up a transitional system for defining the tariff component that covers the cost of purchasing and dispatching energy for the captive market, given the upcoming start-up of the Power Exchange. Once the exchange is up and running, in fact, according to the new consolidated act both the fuel-cost component (indexed to international fuel prices) and the fixed-generation-cost component (established annually by the Authority) will be replaced by the estimated average price for the sale of electricity by the Single Buyer to distributors, which will cover the Single Buyer's procurement and operating costs. The estimated price, flat or by time of use, will take account of the price of every electricity purchase arrangement made by the Single Buyer (Power Exchange, bilateral contracts, contracts for differences, imports and CIP6) as well as the dispatch costs incurred.

With the start-up of the Power Exchange and the opening of the new regulatory period, it was necessary to replace the standard analysis of the trend in average tariff components—based on the distinction between variable and fixed costs—with a new method reflecting the electricity sector’s evolution into a system of distinct structures run by a multitude of businesses specialized in activities that were once performed by comprehensive firms. This way, a distinction can be made between tariff components stemming from activities still performed by effective monopoly holders (transmission and distribution), which are established from above or subject to price caps, and those pertaining to competitive activities (generation) that are determined by market law.

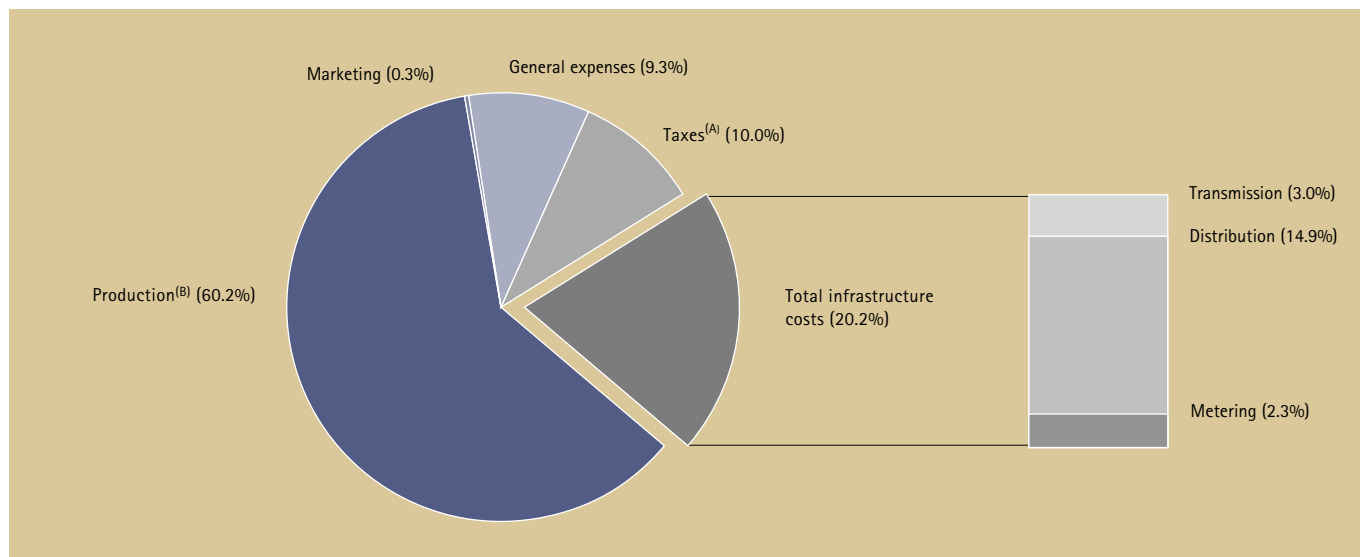
In April, the average national tariff was 10.04 eurocents/kWh net of taxes, a decrease of 2.1 percent with respect to January 2004.

TAB. 19 STRUCTURE OF THE PRICE OF ELECTRICITY FOR END CUSTOMERS DURING THE SECOND REGULATORY PERIOD

ACTIVITY	CAPTIVE-MARKET END CUSTOMER		FREE-MARKET END CUSTOMER
	NON-RESIDENTIAL	RESIDENTIAL	
Production	<ul style="list-style-type: none"> – Regulated tariff, specific component of sale price, calculated as Single Buyer’s average purchase cost of electricity through Power Exchange, bilateral contracts and contracts for differences – Regulated tariff ^(A) included in the component covering electricity procurement costs 	Regulated tariff ^(A) included in the component covering electricity procurement costs	Market prices: bilateral contracts and Power Exchange
Dispatch	Regulated tariff, specific component of sale price, calculated as Single Buyer’s dispatch fee	Regulated tariff ^(A) included in the component covering electricity procurement costs	Dispatch fee
Transmission	Regulated tariff, specific component	Regulated tariff ^(A) not shown as specific component	Regulated tariff, specific component
Distribution	Basic and special tariff options	Regulated tariff ^(A) not shown as specific component	Basic and special tariff options
Metering	Regulated tariff, specific component	Regulated tariff ^(A) not shown as specific component	Regulated tariff, specific component
Vending (marketing services)	Regulated tariff, specific component	Regulated tariff ^(A) not shown as specific component	Market mechanisms

(A) Each utility may offer tariff options in addition to the Authority’s D1, D2 and D3, subject to the Authority’s approval.

FIG. 10 BREAKDOWN OF THE NATIONAL AVERAGE TARIFF FOR THE TRANSPORT AND SALE OF POWER TO CAPTIVE-MARKET CUSTOMERS AS OF 1 APRIL 2004



(A) Taxes are set pro-forma at 10 percent of the average tariff.

(B) Production includes the cost of fuel, fixed generation costs, dispatch, green certificate expenses, and remuneration of capacity and interruptibility, as well as costs for the reconciliation of electricity supplied to the captive market in 2001.

Production costs

The fuel-cost component, which reflects the trend in the primary sources from which electricity is generated, decreased throughout 2001 and continued to fall during the first half of 2002. After the reversal of trend in July 2002 and the subsequent stability caused by the tariff freeze, the cost of fuel started to rise again in 2003. For the second quarter of the year, this component reached a high of 47 percent of the full average tariff (net of taxes), compared with 40 percent in May/June 2002, then stabilized at 44 percent during the last quarter of 2003. The component covering fixed generation costs changed little in 2002 and 2003. It fell from 23 percent of the average tariff net of taxes for the first two months of 2002 to 22.1 percent in January 2004.

Since 1 April 2004 the average tariff for the vending service to the captive market has included three new components covering following types of cost:

- remuneration of production capacity, at 0.09 eurocents/kWh; this is an incentive, tied in with prices on the Power Exchange, for producers to make plants available during times of peak demand;
- remuneration for interruptible contracts (0.16 eurocents/kWh);
- GRTN's expenses for the reconciliation of electricity supplied to the captive market in 2001 (0.01 eurocents/kWh).

Total production costs—6.72 eurocents/kWh, including expenses for green certificates as well as the three components above—make up 66.9 percent of the full tariff net of taxes, compared with 64.5 percent at the start of 2002.

Transmission, distribution, metering and vending costs

The tariff component covering the costs of transmission, distribution and metering (including those for marketing the vending service) amounted to 25.3 percent of the total tariff net of taxes in the first two months of 2002. In the second quarter of 2004, it came to 2.28 eurocents/kWh and made up 22.7 percent of the tariff. The sales-marketing component, which can be shown separately since April 2004, stands at 0.03 eurocents/kWh.

General system costs and other tariff components

After a relatively stable period in 2002, general system costs (including the UC tariff components) and their incidence on the average tariff decreased during the first quarter of 2003—and even more so during the second—due to the reduction in the charge for renewable and assimilated source incentives. For the second quarter of 2004 these costs averaged 1.04 eurocents/kWh and made up 10.4 percent of the full tariff, net of taxes. Determined on the basis of government measures, this component covers various cost items, namely:

- costs for the production of electricity from renewable and assimilated sources (0.61 eurocents/kWh); this is the most sizable of the general system costs, used to offset the difference between the price of CIP6 power withdrawal by GRTN and the revenues from its sale to the captive and free markets via auction (component A3);
- stranded costs (0.14 eurocents/kWh): reimbursement for the investments made and the commitments assumed by the former monopoly holder and by other producers/distributors prior to the start of liberalization, which the competitive market might fail to amortize or honour (component A6);
- costs for the dismantling of nuclear power plants (0.06 eurocents/kWh) (component A2);
- research conducted by power companies in the general interests of the country (0.03 eurocents/kWh) (component A5);
- the equalization of grants given to replace special tariff systems, currently set at zero; the purpose of such grants is to refund utilities for the lower revenues earned by virtue of legally mandated special tariffs for certain parties (the State Railways, coastal municipalities, etc.) (component A4).

The other tariff components cover the following:

- the equalization of electricity procurement costs (component UC₁ of the sale tariff, currently set at zero);
- the equalization of transmission and distribution costs over networks with mandatory third-party connections and costs for integration mechanisms (component UC₃ of the distribution tariff, 0.03 eurocents/kWh);
- tariff supplements and isolated networks (component UC₄ of the sale tariff, 0.03 eurocents/kWh);
- discrepancies between actual and standard leakage (component UC₅ of the sale tariff, 0.06 eurocents/kWh; free-market customers pay this component together with the dispatch fee);
- quality (component UC₆ of the distribution tariff, 0.08 eurocents/kWh).

SYSTEM COSTS

The Electricity Equalization Fund

The new consolidated act for regulatory period 2004–2007 governs the administration of special accounts by the Electricity Equalization Fund (Cassa Conguaglio per il Settore Elettrico, or CCSE) in connection with equalization and integration mechanisms, the setting of various tariff components (system costs and other components), and the procedures for collecting income and administering the management accounts.

Some of those accounts serve for equalization purposes, while others ensure coverage of the general costs of the electric system, i.e. costs that must be borne by both free- and captive-market customers because they finance activities for the common good.

In addition to its traditional role as an accounting and administrative document, the new consolidated act has authorized the CCSE to perform inspections of an administrative, technical, accounting and managerial nature, consisting of the examination and confrontation of parties, the reconnaissance of sites and plants, and the research, inspection and comparison of documents where such action pertains to its mandate.

Nuclear costs

The Authority calculates and adjusts the costs relating to the dismantling of nuclear power plants and the closure of the nuclear fuel cycle, activities performed by Società Gestione Impianti Nucleari Spa (SOGIN)—sometimes in collaboration with public entities or other companies—according to criteria of economic efficiency. Resolution 71 of 23 April 2002 set nuclear costs for the period 2002–2004, and recommended ways of ensuring economic efficiency in the performance of these duties.

The average cost for these activities was raised from 0.05 to 0.06 eurocents/kWh as from the second quarter of 2003 (Resolution 23 of 24 March 2003), in order to guarantee enough income to cover the allowed costs as per Resolution 71/02.

In 2003, the Authority monitored SOGIN's work by examining the status report SOGIN submitted in September, reviewing the 2003 financial statements and setting up technical meetings. Nuclear costs for the next three years will be adjusted on the basis of the long-term plan of work that SOGIN will present to the Authority by the deadline of 30 September 2004 for the recognition of estimated costs for 2005–2007.

There were some important legislative changes during the course of 2003. By order of the president of the Council of Ministers (Decree 3267 of 7 March 2003), SOGIN's chairman was appointed commissioner of nuclear materials safety, and the Smantellamento Impianti del Ciclo del Combustibile Nucleare (SICN) consortium was wound up on 1 July 2003 and its activities transferred to SOGIN.

Law 368 of 24 December 2003 introduced new measures regarding the location and building of the national radioactive waste disposal site, changing the previous legislation with regard to the type of waste allowed, the parties responsible for situating and building the site, and the financing of its construction.

The same law instituted territorial compensation measures, to be paid for through “a component of the electricity tariff, amounting to 0.015 eurocents per kWh consumed”, which will go to the locations of nuclear power plants and nuclear fuel cycle facilities and, as from the opening of the national disposal site, to the town where the site is built and to neighbouring towns, the province and the region in proportion to the allocation of radioactive waste.

With Resolution 46/04, the Authority postponed the creation of a specific tariff component until the means of assigning the compensation pursuant to Law 368/03 were defined, and ordered the total annual amount of the compensation to be charged temporarily to the account for the financing of residual nuclear activities, whose balance is sufficient for that purpose.

Stranded costs

Law 83 of 17 April 2003, “Urgent measures on the subject of general costs for the electric system”, put Decree 25 of 18 February 2003 into law with certain amendments.

While liberalization can produce extra costs for the former monopoly holder, it can also generate extra profits, as in the case of hydroelectric revenue. In a monopolistic system, allowed tariffs are determined by the cost of every source, while in a market context the original costs can no longer be distinguished and prices tend to level out at the cost of the most expensive source. The revenue, therefore, is the higher value acquired by hydroelectric and geothermoelectric production with respect to thermoelectric power, and its extraction reduces the additional charge to consumers stemming from the possible emergence of stranded costs. If left to benefit producers/distributors, the higher value would create revenue for those companies and constitute an expense for the electric system, as a direct consequence of liberalization, by forcing higher tariffs on consumers that are not justified by greater costs. These considerations prompted the decree of 26 January 2000 that ordered the recovery of the higher price of electricity produced by hydroelectric and geothermoelectric plants, as per procedures specified at Art. 5, for a seven-year period starting on 1 January 2000 in order to compensate (if only in part) for the general costs to the electric system.

Law 83/03 eliminated the tax on hydroelectric energy with effect from 1 January 2002, five years earlier than the end date set by the decree of 26 January 2000. This made it necessary to refund to the power companies the amounts they had paid in to the CCSE later than 1 January 2002.

The Ministry of Productive Activities, in concert with the Ministry of Finance and with the approval of the Authority, issued a decree dated 10 September 2003 concerning the reimbursement of the hydroelectric tax for the period 2002–2003. The total amount to be refunded is approximately 508 million.

System research

In 2003 the Centro Elettrotecnico Sperimentale Italiano (CESI) completed the research projects it had begun during its first three-year mandate (2000–2002). Therefore, with Resolution 159 of 23 December 2003, the Authority provided for the final balance to be

paid to CESI for the activities it conducted in 2000–2003 in connection with projects for which funding was granted during the first three years of system research. Resolution 85 of 24 July 2003, in addition to ordering the disbursement of an 80 percent advance on the total amount of funding, amended Resolution 158 of 11 July 2001 by stating that the admissibility of a project for a grant from the Fund for Research Activities (in accordance with Art. 11, par. 2 of a decree issued by the Ministry of Industry, Commerce and Crafts—the Ministry of Productive Activities in its earlier configuration—in conjunction with the Ministry of the Treasury, Budget and Economic Planning on 26 January 2000) be evaluated by the Authority on the basis of investigations conducted by experts appointed and coordinated by the CCSE. With Resolution 41 of 18 March 2004, the Authority approved for such grants the research projects submitted by CESI for the year 2003, for a total of 116,092. The Trade Ministry decree of 28 February 2003 ordered the establishment of a committee of research experts for the electricity sector, which is responsible for all operational activities concerning the funding system for electricity research projects. The purpose of this decision is to ensure transparency and fairness in the selection of research proposals and to make sure the proposals are consistent with the aims of research.