2.
Structure, prices and quality in the electricity sector

Electricity demand and supply in 2009

In the course of 2009, demand for electricity fell sharply with respect to the levels seen in 2008, in tandem with the slowdown of the Italian economy. According to the initial (provisional) figures published by the national network operator (*Gestore della rete nazionale*), electricity demand in 2009 amounted to 317.6 TWh, 6.4% less than the previous year. Over the same period, Italy's Gross Domestic Product (GDP) shrank by 5.1%, with a particularly significant contraction of over 6% in the first half of the year.

Table 2.1 shows the electricity balance in Italy, including the availability and uses of electricity in 2009, compared with the corresponding figures for 2008.

During the year, national production for consumption purposes covered about 86% of the overall requirement (against 88.2% in 2008), with the remainder being met through net imports of 44.4 TWh, an increase of about 11% on 2008.

As regards electricity use, the overall fall in consumption net of losses (down 6.6%) was essentially uniform across the protected and free markets (including the safeguard market). This translated, in energy terms, into a reduction in consumption of over 5 TWh in the protected market and 12 TWh in the free market.

TAB. 2.1

Electricity balance in 2009
GWh

	2008	2009(A)	% CHANGE
Gross production	319,130	289,914	–9.2%
Ancillary services	12,065	11,034	–8.5%
Net production	**307,065**	**278,880**	**–9.2%**
Imports from foreign suppliers	43,432	46,570	7.2%
Exports to foreign customers	3,398	2,121	–37.6%
Allocated to pumped storage	7,618	5,727	–24.8%
Availability for consumption	**339,481**	**317,602**	**–6.4%**
Losses	20,444	19,602	–4.1%
Consumption net of losses	**319,037**	**298,000**	**–6.6%**
Protected market	90,431	85,000	–6.0%
Free market (including safeguard)	208,267	196,000	–5.9%
Self-consumption	20,339	17,000	–16.4%

(A) 2009 figures are provisional. For comparison purposes, safeguard consumption for 2008 and 2009 is included in the free market.

Source: AEEG, from provisional data from Terna.

Market and competition

Structure of electricity supply

National Production

Total gross electricity production amounted to 289.9 TWh in 2009, 9.2% down on the previous year. Breaking down the figures by source gives a reduction of 14%, or about 218 TWh, in thermoelectric generation (Tab. 2.2) with respect to 2008; a fall of 15.6% in generation from natural gas; and a smaller decline, of 6.1%, in production from oil products. The last-named, however, comes after the sharp 20.2% drop seen in 2008, and the even steeper fall of 32.4% in 2007.

Electricity generation from renewable sources saw an increase of 13% in 2009 with respect to the previous year. The marked increase, of 14.2%, in hydroelectric production was accompanied by rapid growth in wind (up 25.2%) and photovoltaic production (about 750 GWh, nearly three times higher than the 2008 levels).

TAB. 2.2

Gross production by source, 2002-2009
GWh

	2002	2003	2004	2005	2006	2007	2008	2009
Thermoelectric	**227,646**	**238,291**	**240,488**	**246,918**	**255,420**	**258,811**	**253,806**	**218,247**
Solids	35,447	38,813	45,518	43,606	44,207	44,112	43,074	39,000
Natural gas	99,414	117,301	129,772	149,259	158,079	172,646	172,697	145,750
Oil products	76,997	65,771	47,253	35,846	33,830	22,865	19,195	18,020
Other	15,788	16,406	17,945	18,207	19,304	19,187	18,840	15,477
Production from renewables	**49,013**	**47,971**	**55,669**	**49,863**	**52,239**	**49,411**	**59,720**	**67,458**
Biomass and waste	3,423	4,493	5,637	6,155	6,745	6,954	7,523	7,740
Wind	1,404	1,458	1,847	2,343	2,971	4,034	4,861	6,087
Photovoltaic	4	5	4	4	2	39	193	750
Geothermal	4,662	5,341	5,437	5,325	5,527	5,569	5,520	5,347
Hydroelectric, natural sources	39,519	36,674	42,744	36,067	36,994	32,815	41,623	47,534
Hydroelectric, pumped storage	**7,743**	**7,603**	**7,164**	**6,860**	**6,431**	**5,666**	**5,604**	**4,209**
TOTAL PRODUCTION	284,401	293,865	303,321	303,672	314,090	313,888	319,129	289,914
TOTAL HYDROELECTRIC PRODUCTION	*47,262*	*44,277*	*49,908*	*42,927*	*43,425*	*38,481*	*47,227*	*51,743*

Source: AEEG, from Terna data. The figures for 2008 are provisional.

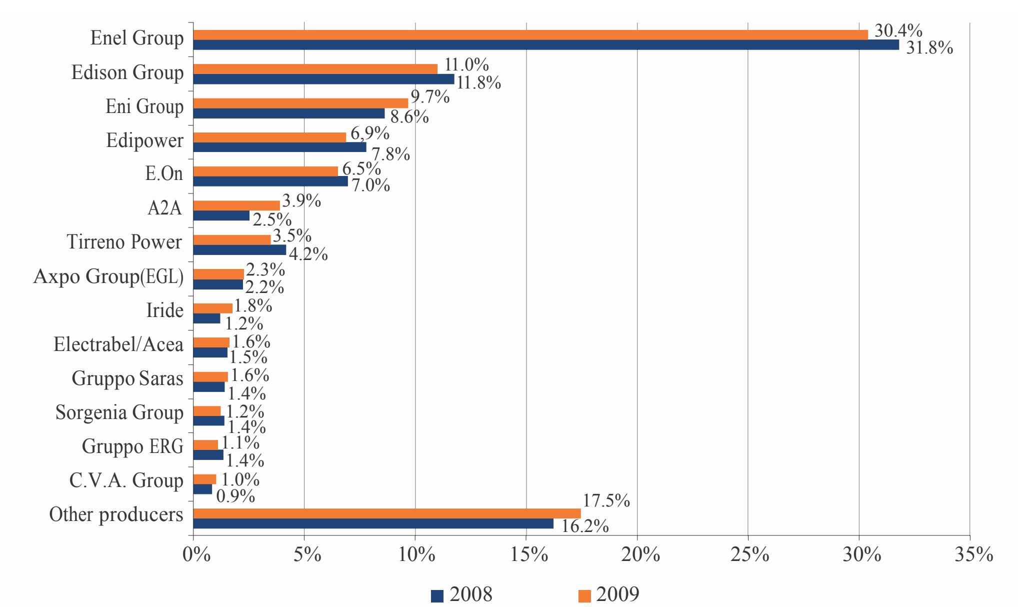
Figure 2.1 shows the principal operators' production share in 2009 compared with that of 2008. Having remained essentially unchanged from 2007 to 2008, ENEL's market share (30.4%) once again contracted with respect to previous years and to 2008 (31.8%). Benefiting from the increased market space thus made available were the ENI group, whose market share in 2009 was about 9.7% (against 8.6% in 2008), and smaller operators. Other major competitors such as Edison, Edipower and E.On do not seem to have gained any advantage from the situation, as evidenced by the dip in their production shares with respect to 2008.

The Herfindahl-Hirschman Index (HHI) for gross generation points to a further reduction in market concentration. The index for 2009 was 1,280, compared with 1,380 in 2008.

FIG. 2.1

Major suppliers' contribution to gross national production

2008 vs 2009; percentage values



Source: AEEG, from operators' declarations.

According to the provisional figures published by Terna–Rete elettrica nazionale, in 2009 new efficient capacity amounting to about 2,300 MW came into play. About two-thirds of this came from thermoelectric plants and the rest from plants fed by renewable and hydroelectric sources (Fig. 2.2). In 2008, the thermoelectric plants run by the 6 main operators provided available generating capacity, for at least 50% of the time, that corresponded to about 90% of installed capacity (Fig. 2.3)

Figure 2.4 shows the percentage shares of electricity produced by the main Italian operators for consumption purposes. These were calculated net of CIP6* energy transferred to the market by the Gestore dei servizi elettrici (GSE)**, and net of energy destined for pumping and for exports.

With respect to the previous year, the ENEL group's position remained essentially stable, while the ENI and A2A groups both increased their market share (by 1%-2%). This was to the detriment of other operators such as the Edison group, Edipower and the E.On group, whose contribution to electricity generation for consumption saw a moderate fall with respect to 2008.

Overall, the degree of market concentration in generation for consumption purposes saw a further, albeit modest, reduction on 2008, in line with the trend in recent years. The HHI in 2009 was 1,579, down from 1,590 in 2008.

Table 2.3 shows the percentage contribution made by the principal groups to national thermoelectric production, with reference to the main conventional fuels. ENEL confirmed its position as leading producer from conventional sources, with a very high presence in electricity generation from coal (72.8% of the total) and a significant one in generation from natural gas and oil products. The Edison and ENI groups, ENEL's main competitors, have an important presence in thermoelectric generation from natural gas and gas derivatives.

In the renewables sector, ENEL confirmed its position as lead national operator in production from both hydroelectric (56%) and geothermal (100%) sources. International Power is the main wind power producer, with 17.1% of the market, while A2A is the leading national electricity producer from biomass, biogas and solid wastes (Tab. 2.4).

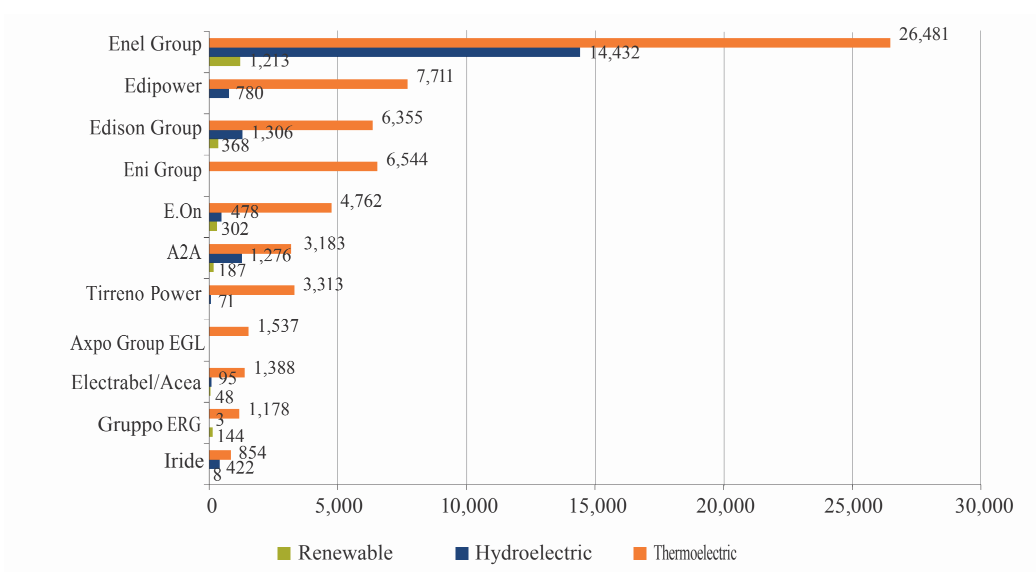
* "CIP6" energy refers to electricity produced from plants fed by renewable or assimilated sources for which economic incentives are envisaged under Interministerial Price Committee (CIP) Resolution 6 of 29 April 1992

** The *Gestore dei servizi energetici Spa* (GSE) is a publicly owned company (Ministry of the Economy) which promotes, provides incentives for and develops renewables in Italy. It holds a 100% share in the *Acquirente Unico* (AU) and the *Gestore dei mercati energetici* (GME).

FIG. 2.2

Gross available capacity for the major groups in 2009

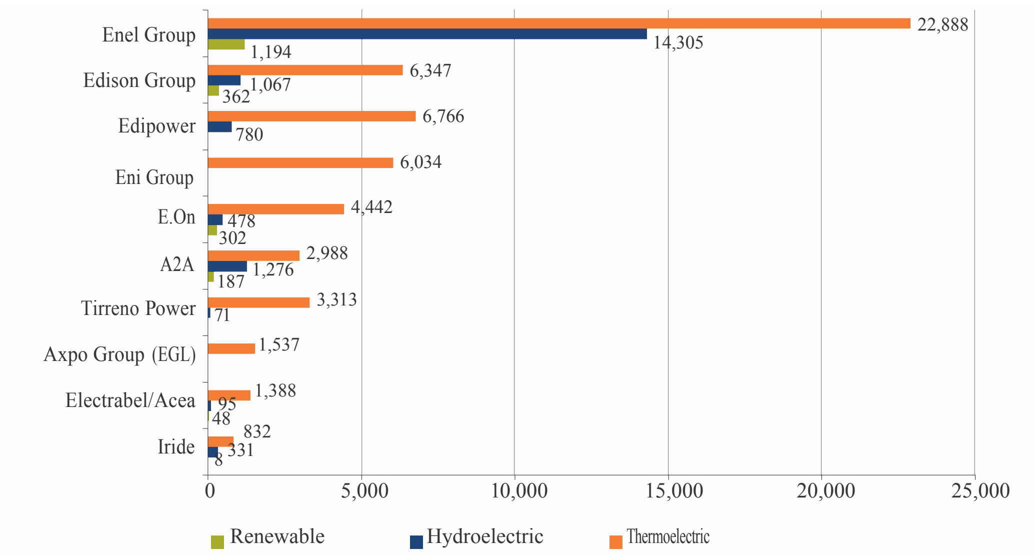
MW



Source: AEEG, from operators' declarations.

FIG. 2.3

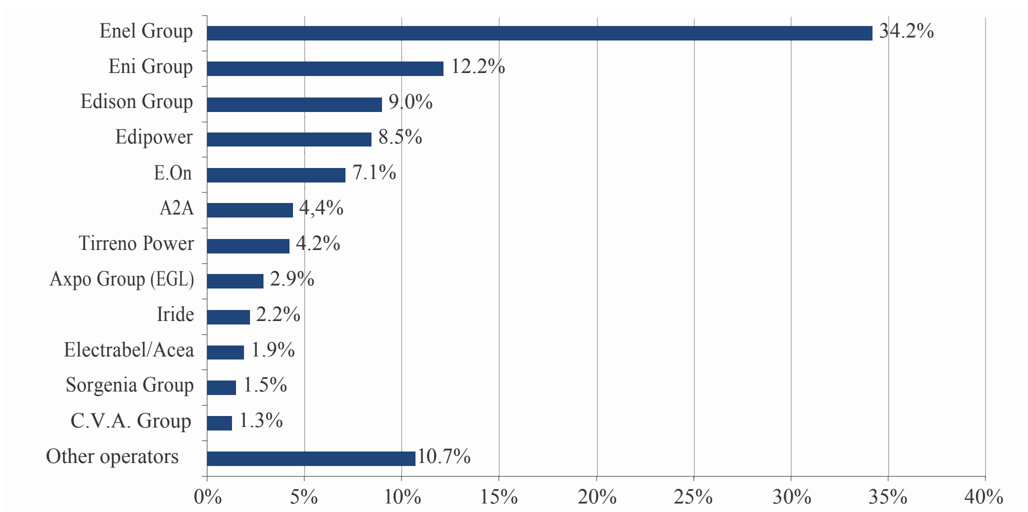
Available capacity (for at least 50% of hours) for the major groups in 2009
MW



Source: AEEG, from operators' declarations.

FIG. 2.4

Major operators' contributions to electricity production intended for consumption 2009
Percentage values



Source: AEEG, from operators' declarations.

TAB. 2.3

Major operators' contributions to thermoelectric production, by source, 2009

Percentage values

	COAL	OIL PRODUCTS[(A)]	NATURAL GAS	OTHER SOURCES[(B)]
Gruppo Enel	72.8	23.9	14.3	0.7
Gruppo Edison	0.0	7.3	17.0	21.8
Gruppo Eni	0.0	11.0	16.4	22.7
Edipower	4.1	28.2	7.7	0.0
E.On	11.1	8.1	7.5	0.4
Tirreno Power	8.2	0.5	4.6	0.0
A2A	3.8	0.0	4.2	0.0
Gruppo Axpo (EGL)	0.0	0.0	4.7	0.0
Gruppo Saras	0.0	1.3	0.0	29.2
Electrabel/Acea	0.0	0.0	2.9	0.0
Iride	0.0	0.3	2.7	0.0
Gruppo Sorgenia	0.0	0.0	2.4	0.0
Other operators	0.0	19.3	15.7	25.2
TOTAL	**100.0**	**100.0**	**100.0**	**100.0**

(A) Includes BTZ and STZ fuel oil, light distillates, diesel oil, petroleum coke, ATZ and MTZ fuel oil, low-grade products and other oil refining residues.

(B) Includes derived gases, heat recovery and expansion of compressed gas.

Source: AEEG, from operators' declarations.

TAB. 2.4

Major operators' contributions to generation from renewables, by source; 2009

Percentage values

	HYDRO	GEOTHERMAL	WIND	BIOMASS, BIOGAS AND WASTE
Gruppo Enel	56.0	100.0	8.7	2.6
A2A	5.2	0.0	0.0	15.7
Gruppo Edison	6.1	0.0	9.8	0.1
Gruppo C.V.A.	5.8	0.0	0.0	0.0
Edipower	5.4	0.0	0.0	0.0
E.On	4.1	0.0	7.2	0.0
Iride	2.5	0.0	0.0	0.6
International Power	0.0	0.0	17.1	0.0
Ital Green Energy Holding	0.0	0.0	0.0	11.7
Sel Edison	1.3	0.0	0.0	0.0
I.V.P.C.	0.0	0.0	11.8	0.0
Dolomiti Edison Energia	1.2	0.0	0.0	0.0
Other operators	12.4	0.0	45.4	69.3
TOTAL	**100.0**	**100.0**	**100.0**	**100.0**

Source: AEEG, from operators' declarations.

Table 2.5 provides a regional breakdown, in terms of number of operators and shares of generation, of the 1,060 electricity producers who responded to the Authority's survey. For the 3 main operators, it also shows installed capacity. Valle d'Aosta and Trentino Alto Adige are the Italian regions with the highest number of operators, mainly small hydro producers, in proportion to the number of inhabitants. Lombardy has the lowest degree of concentration in electricity generation, with the market share held by the 3 principal operators at just over 40%. Piedmont comes next, with around 50%.

The regions where the 3 main operators hold shares of over 80% are, in decreasing order, Liguria, Valle d'Aosta, Marche, Molise, Umbria, Sardinia, Puglia and Lazio. In terms of installed capacity, Basilicata and Lombardy have the lowest degrees of concentration (again, measured as shares held by the 3 principal operators). For Liguria, Valle d'Aosta, Lazio, Marche and Veneto the figure rises to over 90%. Veneto, Emilia Romagna and Tuscany have a significant presence of self-producers with respect to the total number of operators in the region.

TAB. 2.5

Operators' geographical presence in 2009

REGION	NUMBER OF OPERATORS PRESENT	OF WHICH SELF-PRODUCERS	% CONTRIBUTION OF THE 3 MAIN OPERATORS TO REGIONAL PRODUCTION	% CONTRIBUTION OF THE 3 MAIN OPERATORS TO TO INSTALLED CAPACITY IN THE REGION
Valle d'Aosta	16	0	93.5	95.0
Piedmont	187	25	49.5	66.7
Liguria	22	3	97.3	97.1
Lombardy	186	38	40.5	57.4
Trentino Alto Adige	163	17	64.8	69.8
Veneto	96	35	79.9	90.1
Friuli Venezia Giulia	54	4	66.7	76.0
Emilia Romagna	77	26	66.1	68.8
Tuscany	54	17	65.1	68.9
Lazio	39	8	83.4	91.9
Marche	31	1	89.3	91.6
Umbria	26	3	86.7	86.1
Abruzzo	27	3	55.4	63.2
Molise	17	0	89.3	75.3
Campania	57	6	58.4	60.5
Puglia	54	1	86.3	76.2
Basilicata	21	4	62.7	50.1
Calabria	31	0	78.1	81.2
Sicily	41	3	75.1	68.6
Sardinia	24	4	86.7	79.9

Source: AEEG, from operators' declarations.

Incentivised production: photovoltaic

The *Conto Energia* (Energy Account) incentive mechanism promoting electricity production from photovoltaic plants came into effect in September 2005. The decree issued by the Ministry for Economic Development and the Ministry of the Environment and the Protection of the Territory and the Sea (hereafter, Ministry of the Environment) on 19 February 2007, which came into force after the publication of Authority resolution 90/07 of 11 April 2007, amended and simplified the original scheme, as illustrated in the Annual Report of 2008.

The new Energy Account envisages that electricity produced by photovoltaic plants that began operating after 13 April 2007 and before 31 December 2008 is entitled to an incentive tariff broken down as shown in Table 2.6. The tariffs are available for a period of 20 years from the date the plant began operating and remain constant, at current values, for the entire period. Architecturally integrated domestic plants producing up to 3 kW enjoy a higher incentive.

For plants that began operating from 1 January 2009 to 31 December 2010, a deduction of 2% for each calendar year after 2008 is envisaged from the values shown in Table 2.6; the values will then remain constant for the 20-year duration of the incentive. The Ministries of Development and of the Environment will redefine the incentive tariffs for plants coming online from 2011 onwards in subsequent decrees.

Photovoltaic plants of up to 20 kW operating through the on-the-spot trading system may also be entitled to a top-up of the basic recognised tariff. To qualify, they must carry out energy efficiency improvements sufficient to reduce by at least 10% the primary energy requirement of the building they are connected to. The top-up payment is calculated as half the percentage by which the building's primary energy requirement is actually reduced (the maximum award envisaged is 30% of the incentive tariff).

TAB. 2.6

Incentive tariffs in the new *Conto Energia* (Min. Decree 19/02/2007)

Nominal capacity in kW; tariffs in €/kWh

NOMINAL CAPACITY	TYPE OF PHOTOVOLTAIC INSTLLATION NOT INTEGRATED	PARTLY INTEGRATED	INTEGRATED
$1 \leq P \leq 3$	0.40	0.44	0.49
$3 < P \leq 20$	0.38	0.42	0.46
$P > 20$	0.36	0.40	0.44

Source: GSE.

Table 2.7 shows the number and capacity of the plants in operation following the introduction of the first Energy Account, as well as their regional breakdown. Table 2.8 provides similar information for plants receiving incentives under the new version of the Account. The total capacity of the plants operating in Italy at 30 April 2010 was about 1.2 GW, a 263% increase on the level recorded a year earlier. Puglia has the highest level of installed capacity, at 228.7 MW, followed by Lombardy (134.9 MW), Emilia Romagna (99.9 MW), Lazio (89.0 MW) and Piedmont (85.9 MW).

TAB. 2.7

The first *Conto energia* (Min. Decree 28/07/2005 and 6/02/2006)

Plants in operation at 30 April 2010; number and capacity in kW

	CLASS 1 $1\ kW \leq P \leq 20\ kW$		CLASS 2 $20\ kW < P \leq 50\ kW$		CLASS 3 $50\ kW < P \leq 1,000\ kW$		TOTAL	
	NUMBER	CAPACITY	NUMBER	CAPACITY	NUMBER	CAPACITY	NUMBER	
Valle d'Aosta	–	–	1	46	–	–	1	46
Piedmont	207	1,440	68	2,745	5	2,208	280	6,394
Liguria	90	432	9	351	1	51	100	833
Lombardy	601	3,380	97	4,149	4	332	702	7,860
Trentino Alto Adige	168	1,039	126	5,636	8	3,698	302	10,373
Veneto	397	2,469	74	3,127	4	1,571	475	7,168
Friuli Venezia Giulia	210	1,178	7	324	2	707	219	2,209
Emilia Romagna	468	2,672	178	7,312	7	2,772	653	12,756
Tuscany	237	1,797	42	1,709	7	4,512	286	8,018
Lazio	274	1,753	54	2,561	4	3,372	332	7,686
Marche	224	1,413	124	5,638	9	3,940	357	10,991
Umbria	162	1,308	89	3,855	2	560	253	5,722
Abruzzo	57	501	36	1,626	5	1,836	98	3,963
Molise	11	80	4	159	1	301	16	540
Campania	105	936	53	2,428	6	5,395	164	8,763
Puglia	316	2,106	234	10,815	20	14,403	570	27,324
Basilicata	49	489	294	14,237	4	2,229	347	16,955
Calabria	71	529	64	3,028	10	7,181	145	10,738
Sicily	226	1,350	69	3,253	10	5,078	305	9,682
Sardinia	92	545	24	1,083	6	5,094	122	6,722
TOTAL ITALY	**3,965**	**25,421**	**1,647**	**74,084**	**115**	**65,238**	**5,727**	**164,743**

Source: GSE.

TAB. 2.8

The new Conto energia (Min. Decree 19/02/2007)

Installations in operation at 30 April 2010; number and power in kW

	CLASSE 1 1 kW ≤ P ≤ 3 kW		CLASSE 2 3 kW < P ≤ 20 kW		CLASSE 3 P > 20 kW		TOTAL	
	NUMBER	CAPACITY	NUMBER	CAPACITY	NUMBER	CAPACITY	NUMBER	CAPACITY
Valle D'Aosta	44	107	50	475	7	444	101	1,026
Piedmont	2,825	7,502	2,749	22,560	348	49,421	5,922	79,483
Liguria	551	1,388	341	2,581	27	3,624	919	7,593
Lombardy	5,375	14,206	4,940	39,872	655	72,944	10,970	127,022
Trentino Alto Adige	1,528	4,199	1,754	16,208	317	35,856	3,599	56,263
Veneto	3,230	8,543	3,470	25,530	355	42,525	7,055	76,598
Friuli Venezia Giulia	1,400	3,848	2,040	13,853	111	11,374	3,551	29,075
Emilia Romagna	3,283	8,527	2,801	22,993	431	55,619	6,515	87,139
Tuscany	2,542	6,641	2,349	19,281	164	23,255	5,055	49,178
Lazio	2,152	5,654	2,170	15,771	159	59,865	4,481	81,289
Marche	1,326	3,508	1,140	9,068	194	41,737	2,660	54,312
Umbria	709	1,954	771	6,347	128	22,207	1,608	30,509
Abruzzo	456	1,213	806	6,183	92	13,886	1,354	21,282
Molise	84	232	140	1,128	18	6,887	242	8,248
Campania	769	2,105	912	6,997	91	13,177	1,772	22,278
Puglia	2,054	5,540	2,688	19,656	360	176,184	5,102	201,379
Basilicata	310	865	291	2,371	102	10,272	703	13,508
Calabria	633	1,738	937	7,105	65	10,472	1,635	19,315
Sicily	1,886	5,171	1,895	13,545	84	18,359	3,865	37,035
Sardinia	2,526	6,992	1,954	14,000	57	16,938	4,537	37,930
TOTAL ITALY	**33,683**	**89,934**	**34,198**	**265,524**	**3,765**	**685,045**	**71,646**	**1,040,503**

Source: GSE.

Anyone responsible for a photovoltaic plant may benefit from additional economic advantages, both by covering part or all of their own consumption and through sales of energy to the grid. For transfers to the grid, the user can adopt an "indirect" sales model by entering into a dedicated withdrawal agreement with the GSE under Authority resolution 280/07 of 6 November 2007 as amended.

The on-the-spot trading service, which was up-dated through Resolution ARG/elt 74/08 of 3 June 2008, makes it possible to offset electricity produced and injected to the grid at a given time with electricity withdrawn and consumed at a different time. Resolution ARG/elt 74/08 specifically envisages that the on-the-spot trading service should no longer be delivered by distribution companies but solely by the GSE.

Users of on-the-spot trading are the owners of, or have at their disposal:

- plants fed by renewable sources with capacity of up to 20 kW and those with capacity of between 20 kW and 200 kW which began operating after 31 December 2007
- high-yield co-generation plants with capacity of up to 200 kW.

With the aim of eliminating the limits and problems encountered under the previous regulations, the new on-the-spot trading system is structured in such a way that users can purchase all of the electricity withdrawn. Users also sign an on-the-spot trading agreement with the GSE, under which the GSE takes delivery of the electricity injected, sells it on the market and pays a financial contribution to the user. This is intended to:

- provide financial compensation for any difference between the value of the electricity injected to the grid and the value of the electricity withdrawn
- reimburse the variable part of the charges payable for the use of the grid (transmission and dispatching) and general system costs (only in the case of renewable sources). In this case, the quantity of electricity withdrawn must be equal at most to that injected ("swapped" electricity).

By avoiding offsets between quantities of electricity with different economic values, the current regulations ensure that electricity flows are transparent and the electricity injected and withdrawn is correctly priced. They also make it possible to quantify any costs not applicable to operators applying for on-the-spot trading; these costs continue to be charged to users of the electricity system.

Incentivised production: solar thermal energy

Solar thermal plants, unlike photovoltaic plants, indirectly convert solar energy into electricity after first transforming solar into thermal energy in a heat-conducting fluid.

The ministerial decree of 11 April 2008 defines the incentive mechanism for solar thermal plants, including newly-built hybrid installations[1] that have begun operating since July 2008, the date when the Authority's implementing Resolution (ARG/elt 95/08, of 14 July 2008) was published.

The incentives, calculated on the basis of the tariffs shown in Tab. 2.9, are granted solely for the production of solar energy and are added to the revenue from the sale of the electricity generated and injected to the grid.

The tariff values shown refer to plants that began operating between 14 July 2008 (when Resolution ARG/elt 95/08 was published) and 31 December 2012. For installations commissioned between 1 January 2013 and 31 December 2014, a 2% deduction will be applied to the tariffs for each calendar year after 2008 (rounded to the third decimal).

In the absence of further decrees issued jointly by the Economic Development and Environment Ministries in agreement with the *Conferenza Unificata* (the body bringing together central and local government), for plants commissioned after, and for the years following, 2014, the tariffs established by the decree of 11 April 2008 will continue to apply. The incentive is granted for a period of 25 years from the start of operations.

1 In hybrid plants, solar energy is integrated with a conventional thermoelectric generating unit, while in non-hybrid plants all of the solar energy is channelled into the final thermodynamic electricity generation cycle.

TAB. 2.9

Incentive tariffs for solar thermal plants (Min. Decree 11/04/2008)

TYPE OF PLANT	€/kWh
Plant where the solar component is over 85%	0.28 + electricity sales
Plant where the solar component is from 50% to 85%	0.25 + electricity sales
Plant where the solar component is less than 50%	0.22 + electricity sales

Source: GSE.

Incentivised production: CIP6 and other GSE withdrawals

In 2009, the electricity withdrawn by the GSE under art. 3.12 of Legislative Decree 79 of 16 March 1999 and Authority Resolution 108/97 of 28 October 1997 amounted to 36,194 GWh. This corresponds to 13% of net national production and represents a decrease of about 5.5 TWh with respect to 2008.

A detailed analysis of the assimilated energy enjoying CIP6 incentives shows that the overall reduction seen in 2009, of 4.9 TWh, was the result of the notable fall in electricity withdrawn from new plants using process or residual fuels or recovered energy (down 9.8 TWh). Another contributing factor was the decline (of 0.7 TWh) in electricity generation by new plants using hydrocarbon fossil fuels, while electricity generated from existing plants increased by about 5.7 TWh. Assimilated electricity under the CIP6 agreement accounted for 13.6% of net conventional thermal generation in 2009, in line with the figure for 2008.

The reduction in CIP6 production from renewable sources in 2009, of about 0.6 TWh, was mainly a result of the decline in generation from new photovoltaic plants, biomass, municipal solid waste (MSW) and equivalent (down 0.7 TWh) and from wind and geothermal plants (down 0.5 TWh). Energy generated by existing plants increased by about 0.9 TWh. The CIP6 agreements for plants generating energy from renewables accounted for about 10.3% of total net renewable production, a drop of around 12.7% on 2008.

TAB. 2.10

GSE Withdrawals: CIP6 and Resolution 108/97 electricity

GWh

	2005	2006	2007	2008	2009
CIP6	50,296	48,340	46,462	41,653	36,194
- of which assimilated	40,463	39,068	38,268	34,224	29,364
- of which renewable	9,833	9,272	8,194	7,429	6,830
Resolution 108/97	966	689	115	54	-
TOTAL	**51,262**	**49,029**	**46,577**	**41,707**	**36,194**

Source: AEEG, from GSE data.

TAB. 2.11

Withdrawals of CIP6 electricity from assimilated sources, 2004-2009

GWh

	2004	2005	2006	2007	2008	2009
New plant	34,182	25,097	20,465	16,935	13,658	3,139
- of which plants using process, residual or energy recovery fuels	17,773	12,891	13,290	12,929	12,041	2,210
- of which plants using fossil fuels with hydrocarbons	16,409	12,206	7,175	4,006	1,617	930
Existing plant	8,086	15,366	18,603	21,333	20,566	26,224
TOTAL	**42,268**	**40,463**	**39,068**	**38,268**	**34,224**	**29,364**

Source: AEEG, from GSE data.

TAB. 2.12

Withdrawals of CIP6 electricity from renewable sources, 2004-2009

GWh

	2004	2005	2006	2007	2008	2009
New plant	10,031	9,685	8,958	7,857	7,015	5,527
- of which reservoir, river basin or run-of-river hydro over 3 MW	1,397	1,181	987	591	578	375
- of which run-of-river of up to 3 MW	334	184	137	88	84	37
- of which wind and geothermal	3,417	3,040	2,566	2,217	1,687	1,165
- of which photovoltaic, biomass, waste and equivalent	4,648	5,084	5,198	4,949	4,666	3,950
- of which upgraded hydro plant	234	196	70	13	-	-
Existing plant	100	148	314	337	414	1,303
TOTAL	**10,131**	**9,83**	**9,272**	**8,194**	**7,429**	**6,830**

Source: AEEG, from GSE data.

In 2009, the total cost of GSE withdrawals of CIP6 electricity and electricity under Resolution 108/97, as shown in Tab. 2.13, was an estimated 4.2 billion euros, largely (about 70%) linked to the remuneration of CIP6 electricity produced from assimilated plants. The revenue from the sale of this electricity on the Power Exchange net of charges related to contracts for differences and imbalance charges amounted to around 2.3 billion euros, approximately 750 million euros less than in 2008. The cost recoverable in the tariff, corresponding to the difference between costs and revenue from withdrawals of CIP6 electricity, was around 1.9 billion euros, about 500 million down on the previous year.

TAB. 2.13

Costs of and revenues from CIP6 withdrawals and Resolution 108/97 in 2009

Million euros

COSTS AND REVENUES	VALUE
Remuneration assimilated plants	2,926.1
Remuneration renewable plants	1,268.1
Total remuneration CIP6 electricity[(A)]	**4,194.3**
Other metering & transmission costs for CIP6 electricity	9.9
Remuneration of electricity under Resolution 108/97	-
Total withdrawal costs	**4,204.2**
Revenue from electricity sales	2,302.2
Cost to be recovered in tariff (component A_3)	**1,902.0**

(A) End-of-year estimates 2009.

Source: AEEG, from GSE data.

Table 2.14 shows a breakdown by production type of the costs of assimilated and renewable sources receiving incentives under the CIP6 mechanism. The reduction in assimilated-source costs with respect to 2008, of around one billion euros, was the result of a 14% reduction in the amount withdrawn, accompanied by an equal fall in unit remuneration (down 14%). 2009 saw a sharp decrease in the remuneration that can be ascribed to new plants; this was only partly offset by the increased costs associated with electricity withdrawals from existing plants.

As regards renewable sources, the reduction in costs, of 230 million euros, was again mainly attributable to the lower volumes of electricity withdrawn (down 8%) and the fall in unit remuneration (also down 8%).

For new plants, the reduction in the amounts withdrawn and the corresponding remuneration concerned all types of plant, while the costs associated with existing plants increased.

	REMUNERATION TOTAL	QUANTITY	REMUNERATION UNIT
Assimilated sources	**2,926,1**	**29,364**	**99,65**
Assimilated sources – new	409,5	3,139	130,44
- of which plants using process, residual or energy recovery fuels	305,8	2,210	138,38
- of which plants using fossil fuels with hydrocarbons	103,7	930	111,56
Assimilated sources – existing	2,516,6	26,224	95,97
Renewable sources	**1,268,1**	**6,830**	**185,67**
Renewable sources - new	1,141,8	5,527	206,59
- of which reservoir, river basin or run-of-river hydro over 3 MW	56,7	375	151,03
- of which run-of-river of up to 3 MW	5,1	37	139,13
- of which wind and geothermal	186,2	1,165	159,84
- of which photovoltaic, biomass, waste and equivalent	893,8	3,950	226,29
- of which upgraded hydro plant	-	-	-
Renewable sources – existing	126,3	1,303	96,94
TOTAL	**4,194.3**	**36,194**	**115,88**

TAB. 2.14

Breakdown of costs and quantities of incentivised CIP6 electricity by source, 2009

Total remuneration in M€; quantities in GWh; unit remuneration in €/MWh

Source: AEEG, from GSE data.

In the case of assimilated sources, the first 10 industrial groups account for over 98% of electricity generation under the CIP6 scheme. The lion's share, of over one third of all generation, comes from Edison. For withdrawals of electricity produced from renewables, on the other hand, the picture is more variegated. The ENEL and A2A groups each account for around 17% of all renewable generation, followed by International Power (8.3%) and API (8%).

Overall, the 10 leading operators account for approximately 73% of total renewable energy under the CIP6 agreement.

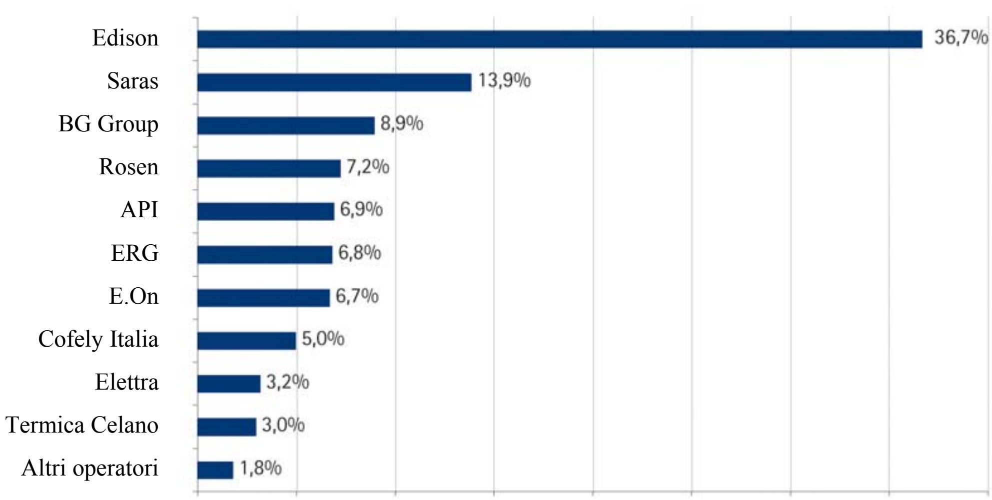


FIG. 2.5

Major operators' contributions to CIP6 production from assimilated sources in 2009

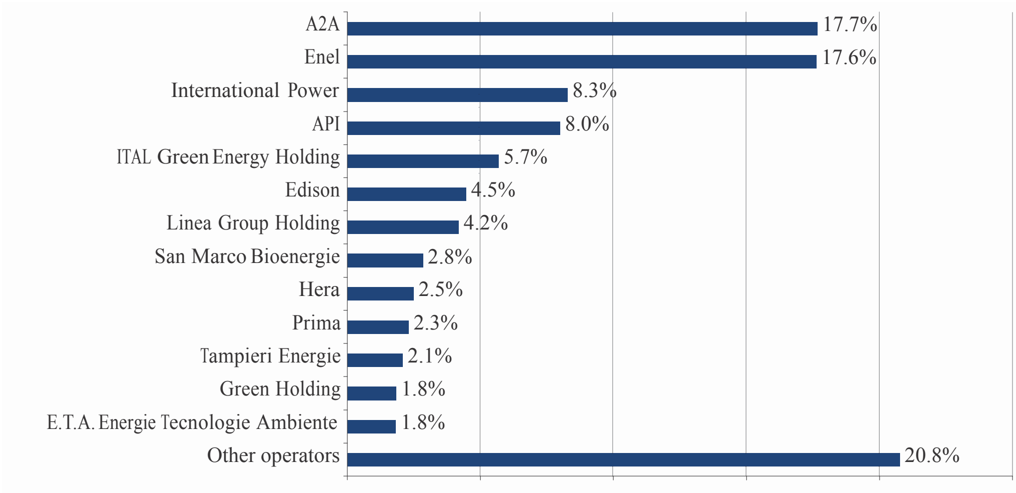
Percentage values

Source: AEEG, from operators' declarations.

FIG. 2.6

Major operators' contributions to CIP6 production from renewable sources in 2009

Percentage values



Source: AEEG, from operators' declarations.

Net imports

According to provisional figures for the year published by Terna (the Transmission System Operator – TSO), the electricity trade balance with other countries amounted to 44,449 GWh in 2009, the difference between imports of 46,570 GWh (up 7.2% on 2008) and exports of 2,121 GWh (down 37.6% on 2008). This means that 14% of Italy's requirement was covered in 2009.

The increase in imports in 2009 was linked to the large increase in electricity from Slovenia (up 2,039 GWh) and from Greece (up 1,980 GWh). Imports from France, on the other hand, fell significantly over the year (by 9.7%).

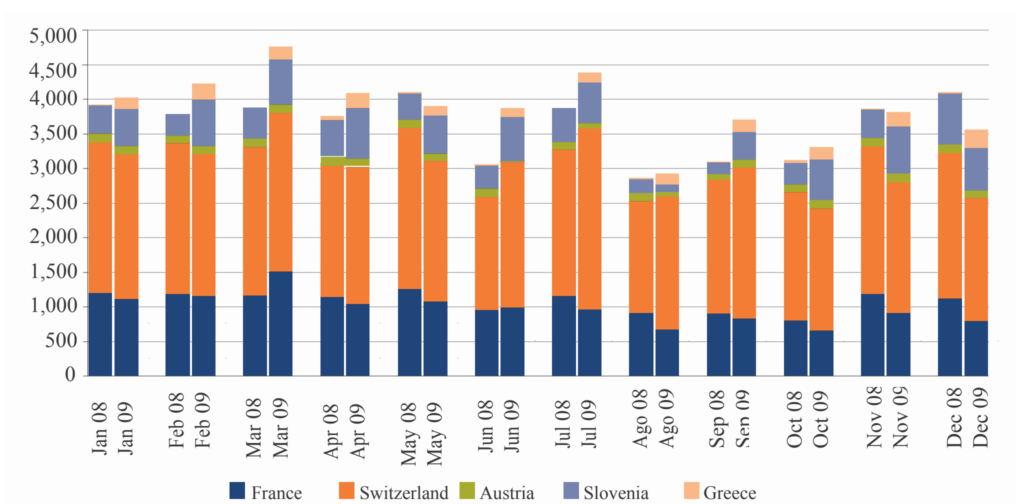
As regards exports, the decrease in electricity flows was confined almost entirely to trade with Greece (down 1,436 GWh).

FIG. 2.7

Electricity imports by border, 2008 and 2009

GWh

2.54



Source: AEEG, from provisional data from Terna.

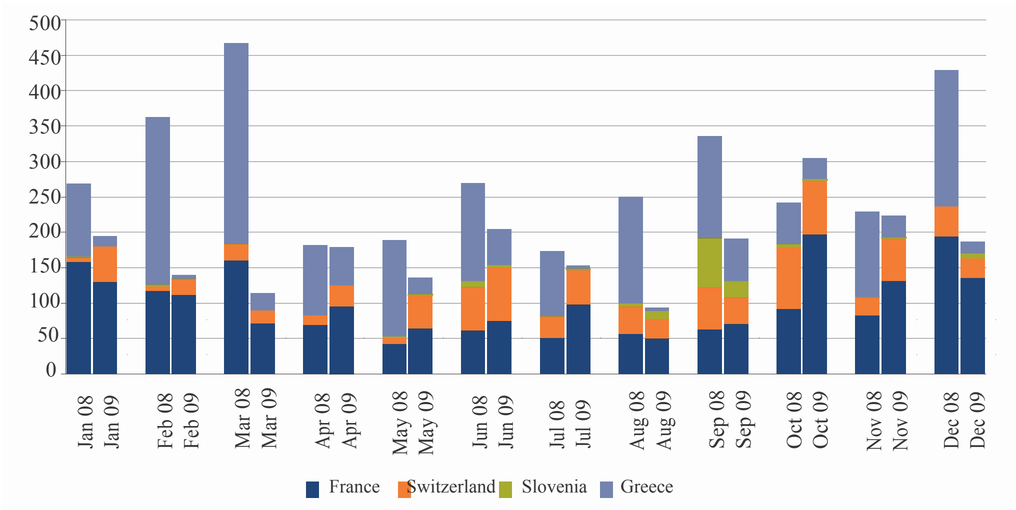


FIG. 2.8

Electricity exports by border, 2008 and 2009

GWh

Source: AEEG, from provisional data from Terna.

Electricity Infrastructure

Transmission

Terna is the principal owner of the national electricity grid (*Rete di trasmissione nazionale* – RTN). Other operators with a stake in the grid are Self Rete Ferroviaria Italiana, Agsm Trasmissione (Verona), Retrasm Asm (Brescia) and Azienda Energetica Trasmissione Bolzano.

The expansion of the transmission line network in the 150-132 kV category is a consequence of the inclusion of the network owned by TELAT (Terna Linee Alta Tensione) as part of the RTN's assets. The high-voltage lines owned by Enel Distribuzione were transferred to this company, established in November 2008 under the name ELAT (Enel Linee Alta Tensione). ENEL and Terna signed a contract for the sale of the holding in ELAT, completed in April 2009, after which the company was renamed TELAT and the newly purchased network was incorporated in the RTN.

In 2009, the RTN also included 491km of 500 kV lines as part of the implementation of the first stage of the SAPEI project linking Sardinia to the Italian mainland.

At 31 December 2009, Terna's reference shareholder, the *Cassa depositi e prestiti* (Loan and Deposit Fund), owned 29.99% of its shares. ENEL and Pictet Asset Management held 5.1% and 4.9% respectively of the share capital, while the remaining 60% was divided among institutional investors and other shareholders.

TAB. 2.15

RTN Assets
Figures refer to 31 December of the year in question

	2007	2008	2009
Number of grid operators	11	8	9
380 kV lines (km)	10,518	10,519	10,514
220 kV lines (km)	11,416	11,387	11,358
150-132 kV lines (km)	22,465	22,436	40,311
500 kV lines, direct current (km)	–	–	491
400 kV lines, direct current (km)	207	207	207
200 kV lines, direct current (km)	862	862	862
Number of 380 kV stations	136	138	139
Number of 220 kV stations	149	147	151

Source: AEEG, from Terna data.

Distribution

A significant operation in the electricity distribution sector in 2009 was the incorporation of Asm Distribuzione Elettricità in Aem Distribuzione Energia Elettrica. This took place on 1 April, with the creation of A2A Reti Elettriche, a company operating in the provinces of Milan and Brescia.

Also in 2009, Enel Distribuzione purchased the services run by the municipalities of Ingria (TO) and Telti (OT), while Stet took over the service operated by Sant'Orsola Terme (TN) city council. Set Distribuzione bought the operation run by Besenello (TN).

A breakdown by ownership of distribution operators shows the prevalence of shareholdings owned by public bodies (44.2%), a figure that is, however, 10% lower than in 2008. Natural persons also hold a significant percentage (32.5%), 13 percentage points higher than in 2008, as do companies not operating in the energy sector (15.3%).

TAB. 2.16

Distributors' ownership composition in 2009

LEGAL STATUS OF OWNERS	%
Public bodies	44.2
Natural persons	32.5
Other companies	15.3
National energy companies	3.9
Local energy companies	2.9
Floating stocks	0.7
Italian financial institutions	0.4
Foreign financial institutions	0.1
TOTAL	**100.0**

Source: AEEG, from operators' declarations.

Table 2.17 shows the geographical breakdown of distribution operators and networks by type of network, as emerges from the data collected by the Authority directly from distribution companies.

The high number of distributors in Trentino Alto Adige region stands out, given that in terms of length the network represents less than 2% of the national total.

TAB. 2.17

Length of distribution networks at 31 December 2009

km

INTEGRATED	HIGH AND VERY HIGH VOLTAGE	MEDIUM VOLTAGE	LOW VOLTAGE	NUMBER DISTRIBUTORS(A)
Valle d'Aosta	57	1,499	2,569	2
Piedmont	32	28,427	63,738	11
Liguria	–	7,022	21,383	2
Lombardy	151	46,814	82,926	13
Trentino Alto Adige	175	7,630	14,953	67
Veneto	56	26,391	61,285	3
Friuli Venezia Giulia	4	8,079	14,957	6
Emilia Romagna	154	32,379	65,767	3
Tuscany	167	26,375	57,405	2
Lazio	614	28,483	65,300	6
Marche	–	11,603	29,796	8
Umbria	–	7,989	18,222	1
Abruzzo	–	9,836	25,370	3
Molise	–	3,629	7,860	1
Campania	–	24,300	58,810	5
Puglia	–	28,695	59,882	3
Basilicata	–	9,808	14,839	1
Calabria	–	17,636	41,591	1
Sicily	–	35,983	75,929	11
Sardinia	–	17,849	33,905	2
TOTAL	**1,411**	**380,427**	**816,489**	**151**

(A) Each distributor is counted once for each Region in which it operates.

Source: AEEG, from operators' declarations.

Italian distributors are 135 in number, with a total distributed volume of 279 TWh.

Enel Distribuzione is the country's leading distributor, with 86.2% of volumes distributed, followed by A2A Reti Elettriche (4.1%) and Acea Distribuzione (3.6%). Other distribution companies hold marginal shares (Tab. 2.18).

TAB. 2.18

Electricity distribution by group, 2009

Electricity distributed, in GWh

OPERATOR	DOMESTIC USERS		NON-DOMESTIC USERS		TOTAL	
	Withdrawal Points	Electricity Distributed	Withdrawal Points	Electricity Distributed	Electricity Distributed	% SHARE OF TOTAL
Enel Distribuzione	24,513,951	53,985	6,725,883	186,872	240,856	86.2%
A2A Reti Elettriche	922,274	1,916	227,242	9,600	11,516	4.1%
Acea Distribuzione	1,267,074	3,043	334,664	7,125	10,168	3.6%
Aem Torino Distribuzione	452,928	720	109,332	2,015	2,735	1.0%
Hera	195,482	427	61,447	1,750	2,177	0.8%
Set Distribuzione	227,547	383	60,860	1,724	2,106	0.8%
Agsm Distribuzione	126,265	280	36,591	1,553	1,833	0.7%
Aim Servizi a Rete	53,555	114	17,909	839	953	0.3%
Azienda Energetica Reti	98,826	213	32,650	700	913	0.3%
Enia	92.210	204	30,427	690	894	0.3%
Other operators	655,317	1,254	183,828	4,076	5,330	1.9%
TOTAL	**28,605,429**	**62,539**	**7,820,83**	**216,943**	**279,482**	**100.0%**

Source: AEEG, from operators' declarations.

Table 2.19 shows distributors' activity broken down by the total and average number of withdrawal points, with volumes distributed for each. Operators in the first category (more than 500,000 withdrawal points) are Enel Distribuzione, Acea Distribuzione, A2A Reti Elettriche and Aem Torino Distribuzione. 53 distributors serve fewer than 1,000 withdrawal points.

TAB. 2.19

Distributors' activity, 2009
Volumes in GWh

NUMBER OF WITHDRAWAL POINTS, BY BAND	NUMBER OF OPERATORS	DISTRIBUTED VOLUMES	NUMBER WITHDRAWAL POINTS	AVERAGE VOL. PER OPERATOR	AVERAGE NO. WITHDRAWAL POINTS PER OPERATOR
1> 500,000	4	265,276	34,553,348	66,319	8,638,337
100,000-500,000	7	9,544	1,228,721	1,363	175,532
50,000-100,000	1	953	71,464	953	71,464
20,000-50,000	8	1,642	235,709	205	29,464
5,000-20,000	22	1,444	226,850	66	10,311
1,000-5,000	40	522	90,350	13	2,259
< 1,000	53	102	19,820	2	374
TOTAL	**135**	**279,482**	**36,426,262**	**2,070**	**269,824**

Source: AEEG, from operators' declarations.

Wholesale market

Electricity trading, with a view to planning generation and consumption units, is carried out on both spot and forward markets.

The regulated spot market (MPE), managed by the *Gestore dei mercati energetici* (Italian Energy Market Operator – GME), is divided into the Day-Ahead Market (MGP) and the Infra-Day Market (MI). On the MGP, electricity is traded for the following day, while on the MI operators can adjust their physical and commercial positions with respect to trading on the MGP.

The MI, set up through Law 2 of 28 January 2009, began operating in November 2009, replacing the Adjustment Market (MA). Law 2/2009 also reformed the Dispatching Services Market (MSD), where Terna procures the resources required for providing transmission and dispatching services and for power system security. Trading on the MI takes place between the close of the MGP and the opening of the MSD. It is divided into 2 implicit auctions, with different, successive, closing times. These allow operators to monitor the state of generating plants more closely and adjust their withdrawal programmes for the different consumption units.

A number of changes to the MSD came into force on 1 January 2010 in accordance with art. 5 of the Ministry for Economic Development's decree of 29 April 2009. These envisage that the MSD will continue to be divided into two stages, a planning and a balancing (MB) stage. Other changes entail:

- the possibility, during each session, to specify a different price for each of the services offered (power reserve, congestion resolution and real-time balancing)
- the sub-division of the MB into 5 consecutive sessions on the day to which the offers refer. In the first session, the offers made by operators at the MSD planning stage are taken into consideration; in the following 4 sessions, operators have the opportunity to adjust their positions on the market up to 90 minutes before the first trading hour.

To increase the flexibility of the system, the market structure was enhanced by developing forward electricity markets. The Forward Market Accounting Platform (PCE), which is designed to record bilateral contracts, began operating in May 2007. In November 2008 the GME also launched a trading platform in the electricity forward market (MTE), enabling physical quantities of electricity to be traded on a multilateral basis.

At the same time, *Borsa Italiana* (the Italian stock exchange) inaugurated trading of electricity derivative financial instruments on the Italian Derivatives Power Exchange (IDEX). These are based on the average purchase price (National Single Price – PUN) and are monthly, quarterly and annual in duration.

With Resolution ARG/elt 203/08 of 23 December 2008, the Authority decided to lower the tolerance ceiling for imbalance penalties from the 3% applied in 2008 to 1.5%. This mechanism, designed to help operators in planning demand, is not compatible with the definitive market This mechanism, designed to help operators in planning demand, is not compatible with the definitive market structure. It will eventually be removed, therefore, once the imbalance regulations are fully in force.

Resolution ARG/elt 203/08 also established that, as of 2009, Terna can no longer submit supplementary offerings on the MGP, unless in exceptional circumstances affecting the national electricity system.

Power exchange: demand in the day-ahead market

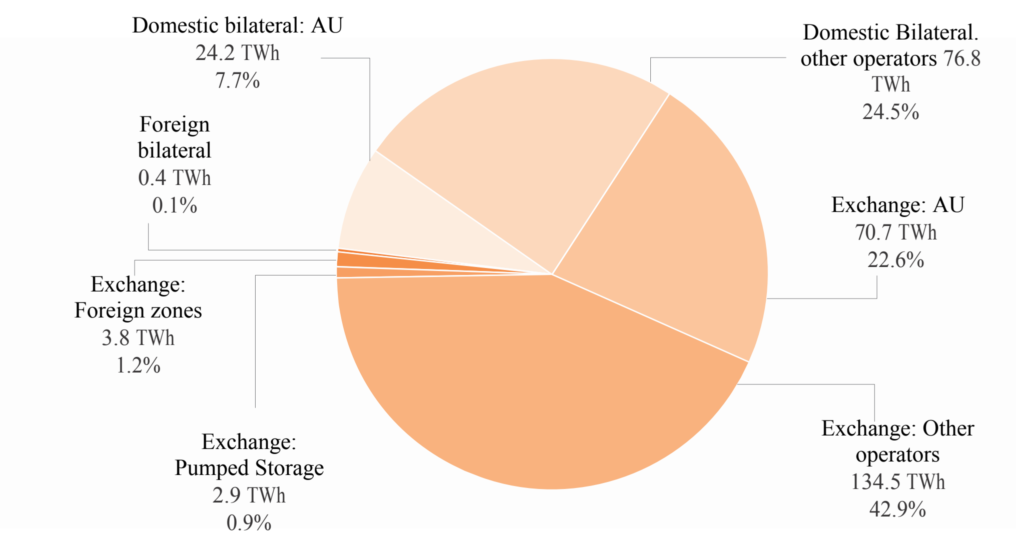
Electricity demand in Italy amounted to 313.4 TWh in 2009, a fall of 6.7% on the previous year[2]. Domestic demand declined by 6.0%, with significant reductions at the zone level, most notably in the North and South macro-zones (with falls of 6.9% and 5.2% respectively). Electricity imports dropped from about 7.3 TWh in 2008 to 4.3 TWh in 2009. A sharp fall, therefore, of 41.1%, in marked contrast with the 91.3% rise seen 2008.

The decline in demand, which began in the last quarter of 2008 with the worsening of the international economic crisis, persisted throughout 2009 and reached its lowest point – down 12.0% – in June.

[2] To take into account the higher number of hours in 2008 (a Leap Year), the percentage change calculations were based on average annual values.

FIG. 2.9

Percentage composition of electricity demand, 2009



Source: AEEG, from GME data.

Operations on the Power Exchange totalled 213.0 TWh, a decrease of 8.2% on 2008. This took market liquidity to 68%, a modest fall on the 2008 figure of 69%. Measured solely on trading on the exchange free from legislative constraints (net, therefore, of electricity from CIP6 plants), market liquidity was 53.5%.

As a result of the progressive contraction of the captive market and the complete liberalisation of sales, purchase offers by the Single Buyer (Italian initials AU) were further reduced in 2009, by 10.8% on the previous year. Demand from other operators declined to a lesser degree: from 137.9 TWh in 2008 to 134.5 TWh in 2009, a decrease of 2.2%.

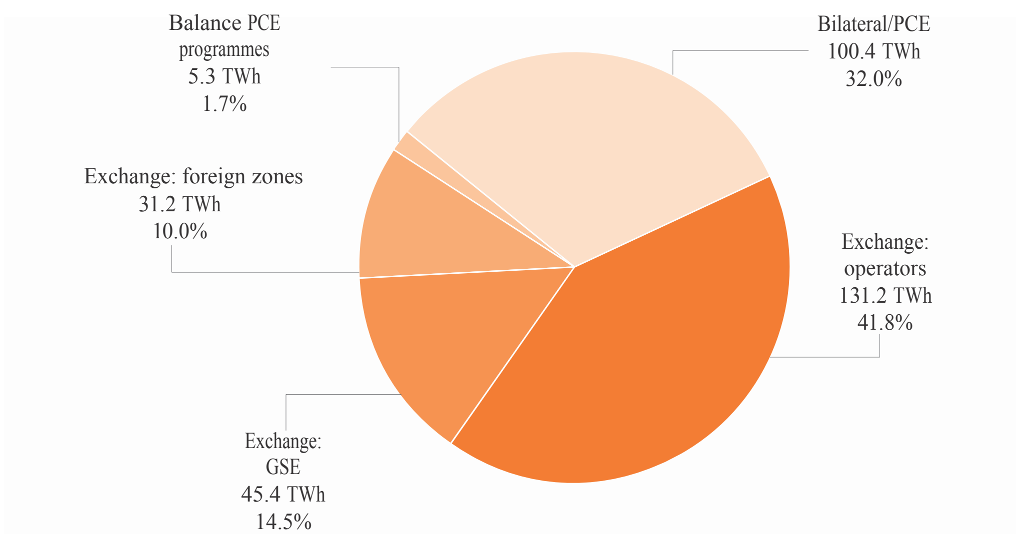
Demand underlying bilateral contracts decreased by 3.5% on the previous year, to 100.4 TWh. This reduction chiefly affected foreign bilateral contracts, which fell by 21.8% on 2008 and, to a lesser extent, bilateral contracts entered into by domestic companies other than the AU, which saw a decline of 8.6%. This fall was partly offset by the increase in bilateral contracts concluded by the AU, which rose by 24.7% on the previous year.

Power exchange: offers in the Day-Ahead market

Volumes offered by Italian companies on the Exchange fell by 10.8% compared with 2008, to 131.2 TWh. To this should be added the 4.9% fall in offers by the *Gestore dei servizi energetici* (GSE)*, which amounted to 45.4 TWh. Sales offers from foreign operators increased significantly (by 43.7%), to 31.2 TWh. The balance of PCE schedules was equal to 5.3 TWh, a significant decline (of 33.4%) from the previous year.

FIG. 2.10

Percentage composition of electricity supply in 2009



Source: AEEG, from GME data.

Power exchange: results on the Day-Ahead Market

The average purchase price (PUN) in the Italian power exchange in 2009 was 63.72 €/MWh, 23.27 €/MWh (26.8%) lower than in 2008. This fall is related to the drastic contraction in demand as a result of the deep economic recession. This is coupled with the significant reduction in variable generation costs, in turn a result of the decline in international fuel prices. The average monthly PUN reached its lowest level (51.82 €/MWh) in June) (Fig. 2.11).

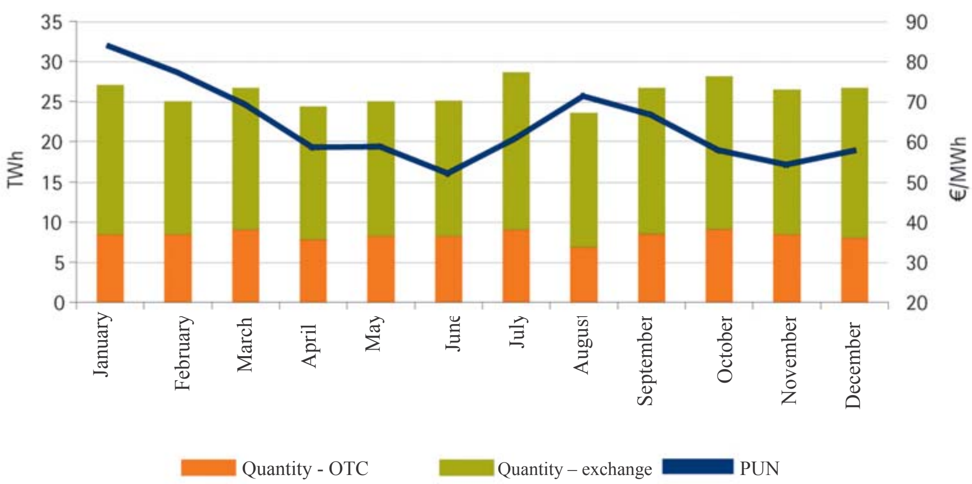
FIG. 2.11

Trend in National Single Price (PUN), 2008 and 2009
€/MWh

Source: AEEG, from GME data.

FIG. 2.12

Volumes traded on Day-Ahead Market (MGP) in 2009
TWh; €/MWh



Source: AEEG, from GME data.

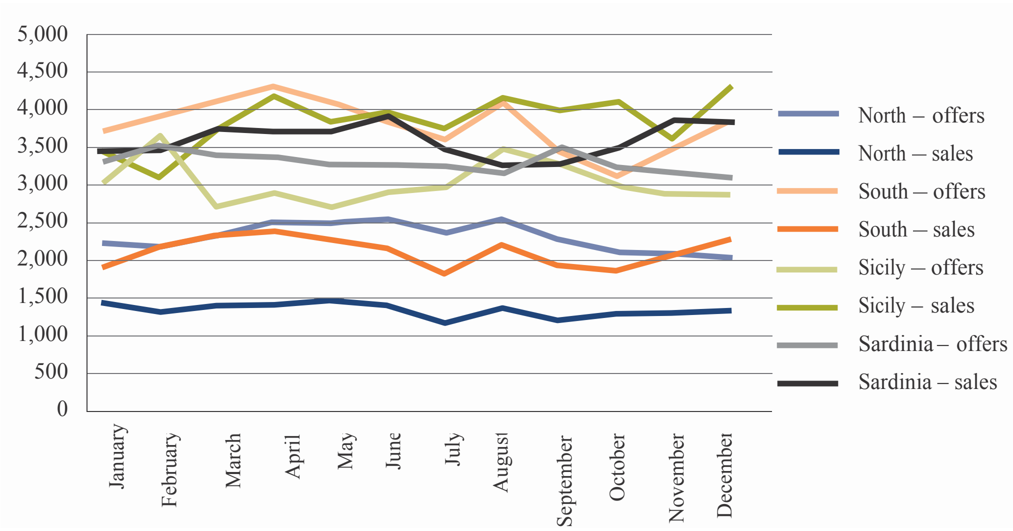
The HHI concentration index, calculated at zone level and on the basis of actual electricity sales and sales offerings (accepted or not), confirms the progressive improvement in the competitive environment in the North macro-zone. Obstacles to the development of fully competitive conditions persist in the zones of Sicily and Sardinia, where the HHI index never falls below 1,800.

The marginal market participant index signalled an improvement in competitive conditions compared with 2008. Indeed, the percentage of total volumes traded for which the marginal operator set the price fell from an average level of

51% in 2008 to 28% in 2009 (Fig. 2.13). For most months of 2009 (with the exception of April and August) the figure was lower than 35%, as was the case in the last quarter of 2008.

FIG. 2.13

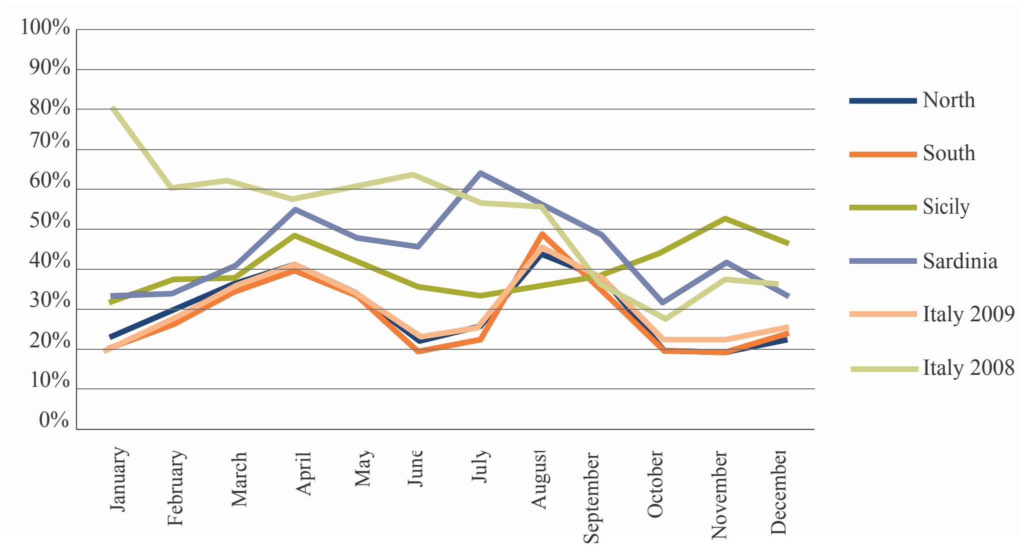
HHI index in 2009



Source: AEEG, from GME data.

FIG. 2.14

Marginal Market Participant Index: share of volumes for which the 1st operator set the price, by macro-zone



Source: AEEG, from GME data.

As regards average prices on the Italian Exchange, for the first time since the Exchange was set up the lowest price, of 59.49 €/MWh, was found in the Southern Zone. In the other zones of mainland Italy the price was just over 60 €/MWh. Sales prices in the two islands were significantly higher, at 82.01 €/MWh in Sardinia and 88.09 €/MWh in Sicily, although the latter partly reduced its price differential with other zones with respect to 2008. Compared with that year, prices fell in line with the change in the PUN, by between 26.4% in Sicily and 31.9% in the Southern Zone. The Sardinia macro-zone saw a smaller fall (of 10.7%) with respect to the average national variation.

An analysis at the monthly level reveals a substantial price reduction in all zones. Exceptions to this were the summer months, when the reduction in the volumes on offer, coupled with steady demand, especially in the islands, created the conditions for greater concentration on the supply side and, as a result, the possibility for the dominant operators in the different market zones to exert market power (Fig. 2.14).

In 2009 national rent rose significantly with respect to the previous year, from 156 million euros to 260 million, an increase of 67.3%. Most notably, September saw a revenue of 50.5 million euros, nearly double that of August (up 98.6%) and nearly triple the figure for September 2008 (up 257%). The transit contributing most to domestic rent is the Centre South-South transit, which saw a considerable increase with respect to the previous year. Rent collected on the North-Centre North and Centre North-Centre South transits saw a decline.

Since 2008 interconnection capacity at the borders has been allocated jointly by neighbouring network operators through explicit annual, monthly and daily auctions. By definition, this mechanism cancels out the congestion rent from abroad, since the cost of congestion is paid in advance at the explicit auction stage.

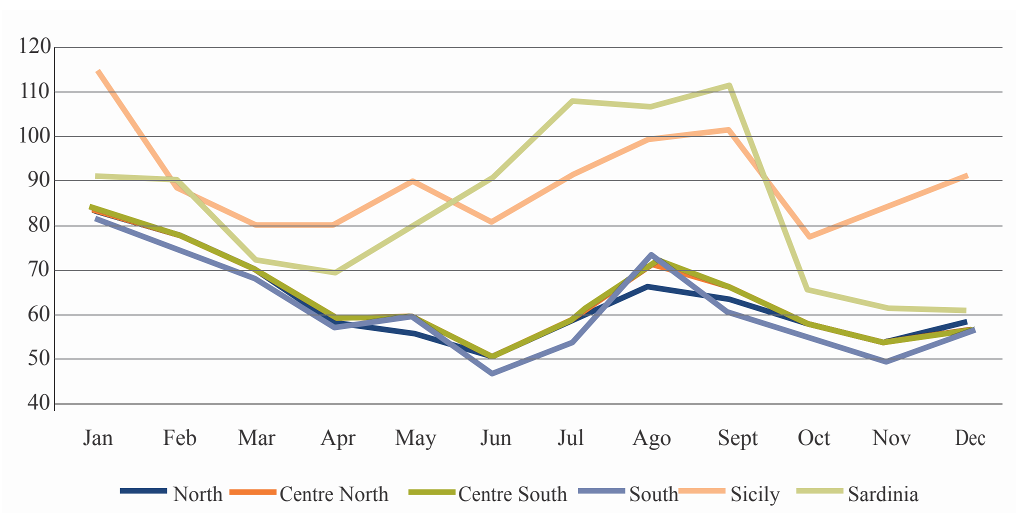


FIG. 2.15

Monthly trend in zone-level prices, 2009
€/MWh

Source: AEEG, from GME data.

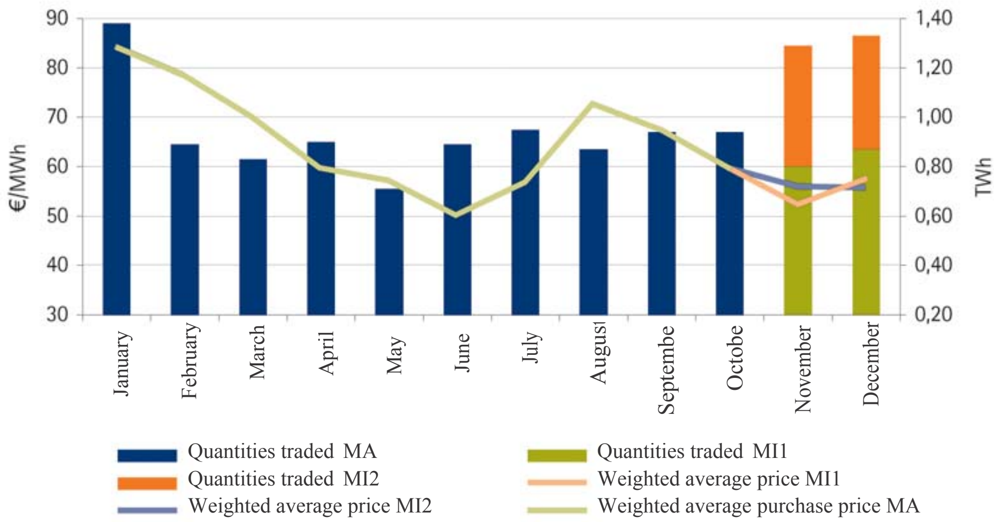
Power exchange: results on the Adjustment and Infra-Day market

Electricity trading volumes on the Adjustment Market (until 31 October 2009) and on the Infra-Day Market (November and December 2009) totalled 11.9 TWh, 2.7% up on the previous year. The weighted average purchasing price was 66.44 €/MWh on the MA, and 54.66 €/MWh and 55.68 €/MWh respectively during the two trading sessions (MI1 and MI2) of the MI. In 2008, the average weighted average price for electricity purchased on the MA was 84.95 €/MWh.

FIG. 2.16

Trend in average weighted prices and quantities on the MA and MI, 2009

€/MWh; TWh



Source: AEEG, from GME data.

Power Exchange: Dispatching Services Market

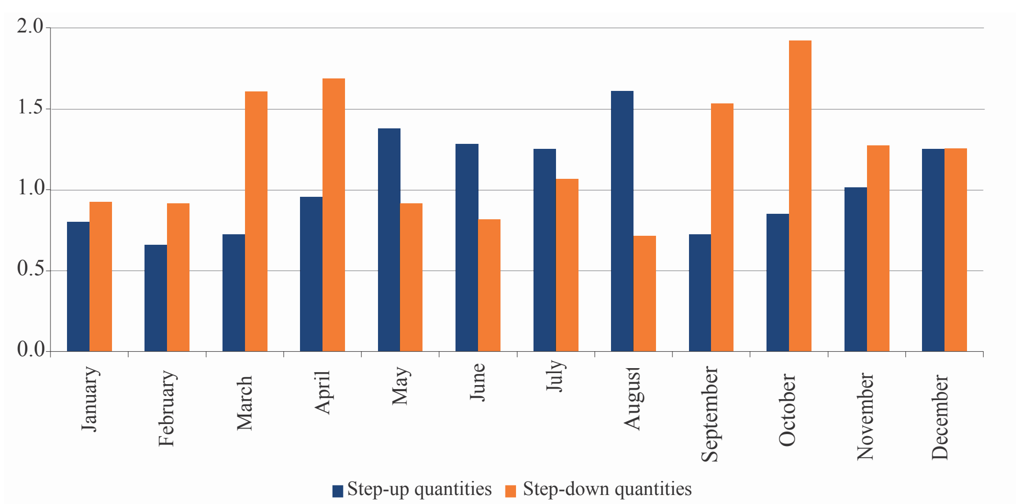
Ex ante step-up purchases on the MSD amounted to 12.5 TWh, an increase of 8.4% on the previous year. Step-down quantities sold *ex ante* were equal to 14.6 TWh, up 30.4% on 2008 – a marked reversal of the downwards trend of the previous two years.

These volumes represented about 4.0% of the total volumes traded on the MGP and showed a strong monthly variability (Fig. 2.17). Indeed, step-up offers were higher in May, June and August (5.5%, 5.1% and 6.8% respectively of the corresponding monthly demand). Step-down demand, on the other hand, was highest in March (6%), April (6.9%) and October (6.8%).

FIG. 2.17

MSD, quantities in 2009

TWh



Source: AEEG, from GME data.

Power Exchange: comparison with main European exchanges

2009 saw a sharp fall in prices on the European power exchanges, with price levels – after the significant rise in 2008 – returning to levels similar to or lower than those of 2007.

This Europe-wide fall of between 21% and 43% was sharpest in Spain and Central Europe, which had seen more marked increases in 2008. As an effect of these movements, prices on the Omel (36.96 €/MWh), EEX (38.95 €/MWh) and Powernext (43.01 €/MWh) exchanges reconverged on those of NordPool (35.02 €/MWh). Once again, Ipex was the exchange with the highest prices (63.72 €/MWh).

The pace of the price contraction in the first half of 2009 differed between Italy and other countries. As the international macro-economic picture worsened and demand for electricity fell as a result, prices in other European countries adjusted almost immediately. In Italy, however, the fall in prices was much slower and more gradual. During the summer months the trend reversed, with Italian prices rising with the economic cycle and prices on the foreign exchanges continuing to fall, thus increasing the price differentials and favouring increased electricity imports to Italy.

The price differential between Italy and other countries began to narrow in September. Prices in the French market saw a modest increase that month and peaked in October, as a result of unexpected shut-downs at French nuclear power stations. October's baseload price reached 70.1 €/MWh, 12.46 €/MWh higher than the Italian Power Exchange (IPEX) price. This movement generated "time windows" in which Italian producers exported electricity to France. In November, French prices saw a marked fall, returning to below IPEX price levels.

The total differential between IPEX and the other main European exchanges was 23.8 €/MWh in 2009, 3.4 €/MWh higher than the previous year.

The differential between peak and off-peak prices on the Italian Power Exchange is fairly marked. The average prices in 2009 at peak and off-peak times[3] were 83.46 €/MWh and 54.47 €/MWh respectively.

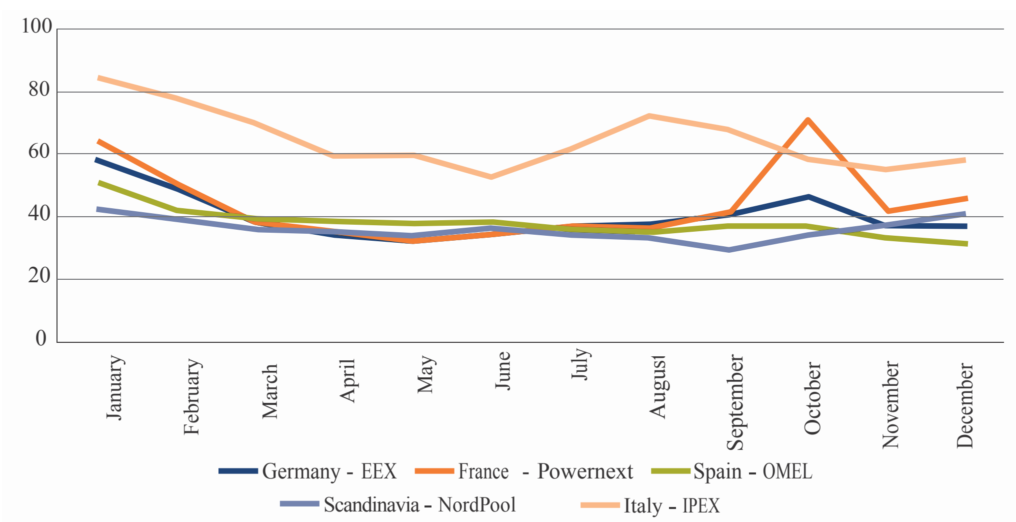
In the other European exchanges lower average prices are generally coupled with a smaller differential between peak and off-peak prices. The average peakload and offpeak prices were 51.13 €/MWh and 33.25 €/MWh respectively on the German exchange, 58.86 €/MWh and 35.59 €/MWh on the French, 39.82 €/MWh and 35.62 €/MWh on the Spanish, and 38.50 €/MWh and 33.39 €/MWh on the Scandinavian exchange.

3 Prices are calculated for all Exchanges on the basis of the hourly bands adopted by the Authority to differentiate electricity values. The average peak price is calculated from the values recorded during the hours corresponding to band F1, and the off-peak price from the remaining hours of the year (bands F2 and F3).

FIG. 2.18

Monthly average price in the main European exchanges, 2009

Average baseload values; €/MWh

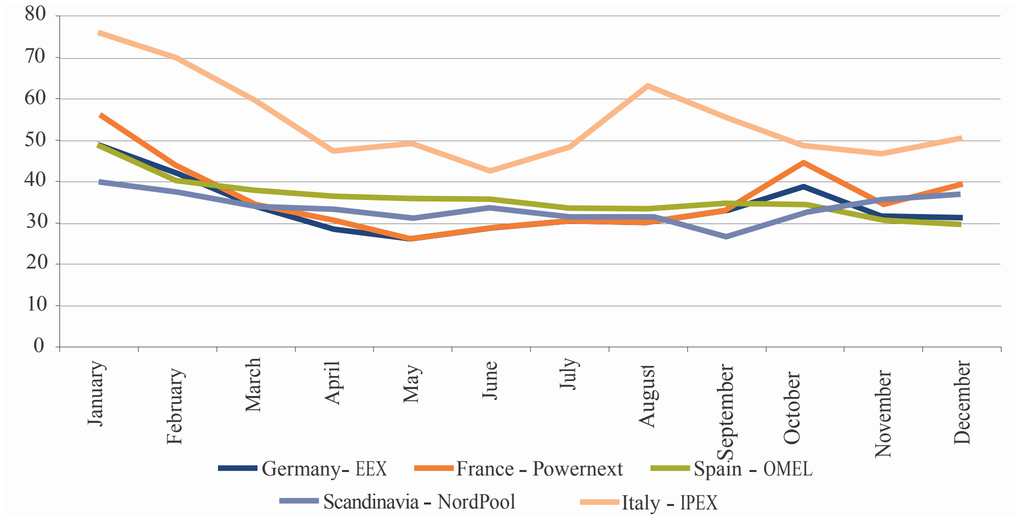


Source: AEEG, using data from European power exchanges.

FIG. 2.19

Monthly average price in the main European exchanges, off-peak hours 2009

€/MWh

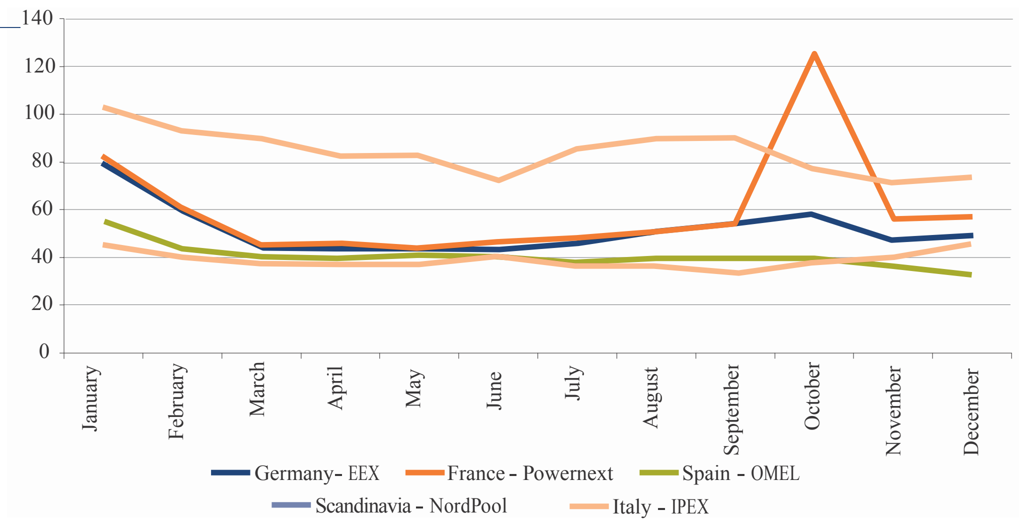


Source: AEEG, using data from European power exchanges.

FIG. 2.20

Monthly average price in the main European exchanges, peak hours

€/MWh



Source: AEEG, using data from European power exchanges.

Energy Accounting Platform (PCE)

The Forward Market Accounting Platform (PCE) is the platform on which bilateral contracts are recorded. Operators can record data concerning quantities and delivery times for forward contracts up to two months in advance of the physical delivery date.

In general, each operator has one or more power delivery accounts (CEI) and one or more power withdrawal accounts (CEP), on each of which they may record purchases and sales. The net result of the new transaction registered must be a net sale in the former case and a net purchase in the latter. The balance on the account determines the amount of electricity that can be delivered/withdrawn or sold/purchased on the MGP.

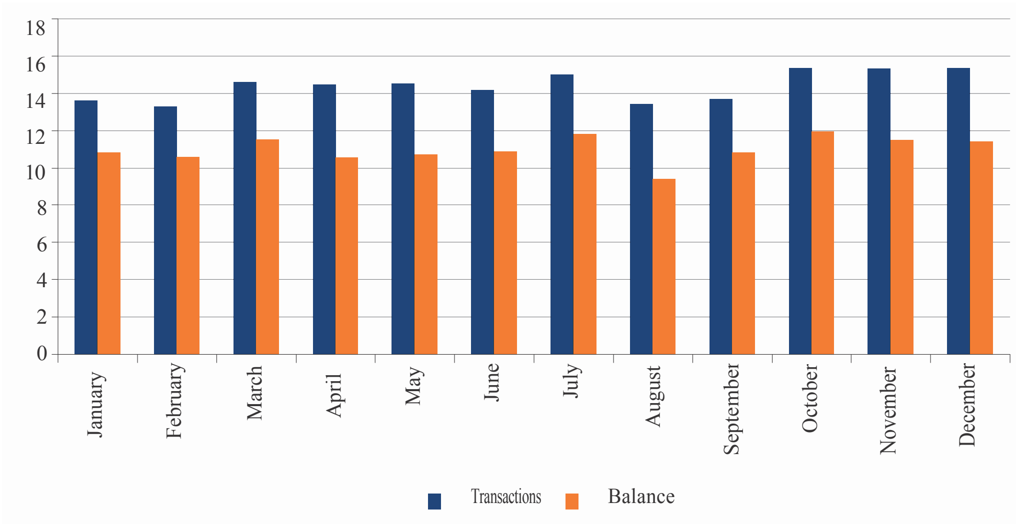
Total transactions recorded in the PCE, with delivery and withdrawal in 2009, amounted to 173.0 TWh (13.8% higher than in 2008).

Most of the contracts registered by operators were non-standard (67.8% of the total), an increase of 15.9% with respect to 2008. The most commonly used of the standard contracts was the baseload (21.0% of the total, a rise of 18.5%). Peak contracts fell by 7.7%. The transactions registered in the PCE resulted in a net position of 131.1 TWh for operators' power accounts, an increase of 7.8%.

FIG. 2.21

Transactions on the PCE in 2009

TWh



Source: AEEG, from GME data.

Forward markets: MTE and IDEX

The Electricity Forward Market (MTE) and the Italian Derivatives Power Exchange (IDEX) are the two regulated forward markets managed by GME and *Borsa Italiana* respectively. Both were launched in November 2008 with the aim of allowing operators to manage their energy portfolios more flexibly.

Following the reform of the rules governing the electricity market under Law 2/2009, since November 2009 it has been possible to trade electricity over a timescale of up to one year on the MTE, with obligatory delivery at the end of that period. Monthly, quarterly and annual delivery periods can also be negotiated. Quarterly and annual contracts are regulated by a cascading mechanism, and monthly contracts by registering the electricity underlying the contract on the PCE.

Contracts were signed in 2009 for a total of 81.0 GWh in volumes traded.

The IDEX is the segment of the Italian Stock Exchange's derivatives market for the trading of financial futures contracts based on electricity with the PUN as reference price. Contracts can be baseload and have monthly, quarterly and annual delivery periods. The operation of the market envisages the presence of the *Borsa Italiana* group's clearing house, the *Cassa di compensazione e garanzia*, to which members of the market must belong and which acts as a central counterparty.

In 2009, total volumes traded on the IDEX amounted to about 15.8 TWh.

On 26 November 2009 the integration of the physical electricity forward market (MTE) and the regulated market for electricity derivatives, the Italian Derivatives Energy Exchange, became operational.

GME and Borsa Italiana have set up a physical delivery option for delivery contracts on the IDEX market. This allows operators authorised to operate on the two platforms to choose, when their last monthly contract expires, whether to regulate their IDEX position through a cash settlement or by transferring their position to the physical delivery platform for financial contracts agreed on the IDEX (Electricity derivatives delivery – CDE). This platform sits alongside the MPE and MTE and enables operators to transfer open positions on the IDEX market by opening a position in which the counterparty is the GME itself.

This mechanism is designed to increase the appeal of regulated electricity markets, where prices are formed on the basis of transparent mechanisms and the satisfactory outcome of contracts is guaranteed by the existence of a central counterparty. This lays the foundations for increased liquidity and reduces risk levels, even over extended timescales.

Sale of CIP6 energy on the market

The electricity withdrawn by the GSE in 2009 was placed on the market under the conditions envisaged by the Ministry for Economic Development's decree of 25 November 2008. For the allocation of the 4,300 MW of CIP6 rights for 2009, the decree envisaged the following arrangements, which are similar to those in force the previous year:

- the CIP6 energy withdrawn by the GSE is offered on the electricity market;
- the capacity to be awarded for 2008 is determined by the GSE on the basis of the estimated total energy to be acquired under existing contracts with producers and on the basis of prudential statistics as to non-programmable sources;
- of the electricity sold to operators through allocation procedures conducted by the GSE, 20% (860 MW) is earmarked for the Single Buyer for supplies to customers in the protected market and 80% (3,440 MW) to customers in the free market;
- the allocation price for the first quarter of 2009 is 78€/MWh. This price is adjusted each quarter under the terms established by the Authority on the basis of the quarterly price index as per art. 5 of the former Ministry for Productive Activity (now Ministry for Economic Development) decree of 19 December 2003;
- the assignee enters into a contract for differences with the GSE and undertakes to procure quantities of electricity on the market that are no less than the allocated hourly quota;
- if the price formed in the market is higher (or lower) than the allocation price, the assignee will receive from (or credit to) the GSE a fee equal to the product of the price differential and the quantity allocated.

In the course of 2009, the Authority up-dated the allocation prices for the second, third and fourth quarters of the year, in accordance with Resolution ARG/elt 11/09 of 28 January 2009. These prices were 65.87 €/MWh, 48.45 €/MWh and 56.86 €/MWh respectively.

For 2010, the Ministry for Economic Development's Decree of 27 November 2009 established that 17% of the electricity withdrawn by the GSE should be passed to the Single Buyer for supplies to customers in the protected market, and 83% to customers in the free market. The allocation price for Q1 2010 is 57 €/MWh and total allocatable capacity for the year, as proposed by the GSE, is 4,100 MW.

TAB. 2.20

Allocation of CIP6 rights
MW

	2009	2010
Enel Energia	1,035	823
Eni	250	261
Edison Energia	374	377
AceaElectrabel Elettricità	20	166
Sorgenia	145	149
E.On Energia	125	149
Energetic Source	185	121
Iride Mercato	81	77
A2A	130	127
EGL Italia	89	72
Hera Comm	106	116
Other	900	965
TOTAL	**3,440**	**3,403**

Source: AEEG, from GSE data.

Markets for the environment

Green certificates market

The green certificates system is a form of incentive, based on market mechanisms, for energy generation from renewable sources.

Under the provisions of Law 244 of 24 December 2007, electricity production from renewables, in plants commissioned or upgraded from 1 April 1999 to 31 December 2007, is eligible for certification of power generation from renewable sources (green certificates) for the first 12 years of operation. Plants that have begun operating or been upgraded since 1 January 2008 are entitled to green certificates for a period of 15 years.

Law 244/2007 also establishes the right, as an alternative to green certificates and at the producer's request, to a fixed tariff, the amount of which depends on the source used, for a 15-year period. This applies to generation by plants fuelled by sources eligible for green certificates and which have an average annual nominal capacity of no more than 1 MW (0.2 MW for wind plants) and were commissioned after 31 December 2007. Installations eligible for green certificates, and which began operating prior to 31 December 2007, will continue to be awarded certificates, the amount of which corresponds to their net power output.

In the green certificates market, demand consists of an obligation on producers and importers to inject a certain amount of energy generated from renewables into the grid each year.

Legislative Decree 79/99 provides that, with effect from 2002, 2% of any electricity in excess of 100 GWh/year produced (net of self-consumption) or imported from non-renewable sources the previous year should be injected to the grid. From 2004 to 2006, the minimum quantity of electricity produced from renewables to be injected into the grid the following year was increased by 0.35% a year, in accordance with Legislative Decree 387 of 29 December 2003. Under Law 244/07, this quota was increased by 0.75% per year for the period 2007-12.

The obligation to inject quotas of renewable energy into the grid may be met not just by producing/importing renewable energy, but also by purchasing green certificates from other operators. Certificates can be traded through bilateral contracts or through the platform organised and operated by the GME.

Table 2.22 shows the transactions in the market run by the GME in the course of 2009 and in the first quarter of 2010. It distinguishes between certificates issued with respect to plants generating electricity from renewables (IAFR certificates) and those issued by the GSE against production from co-generation plants combined with district heating.

No transaction has yet been made involving green certificates for electricity production fuelled by hydrogen or in static plants using hydrogen, i.e., using fuel cells. The table also shows the results of trading conducted on the platform for the registration of bilateral green certificate transactions (Italian initials PBCV). This is an IT platform through which bilateral trading in green certificates can be recorded and regulated.

TAB. 2.21

Results of trading in green certificates (GCs)

Certificates traded in MWh; average price in €/MWh

TRADING PERIOD	TYPE OF GREEN CERTIFICATES REFERENCE YEAR	GME MARKET		BILATERAL	
		CV TRADED	AVERAGE PRICE(A)	CV TRADED	AV. PRICE(A)
2009	GCs Renewables (2006)	437	89.93	35,292	96.17
	GCs Renewables (2007)	112,203	90.47	1,249,167	92.53
	GCs Renewables (2008)	449,381	92.22	5,743,885	95.04
	GCs Renewables (2009)	1,235,489	86.30	12,637,112	85.54
	GCs District Heating (2005)	–	–	10,870	80.71
	GCs District Heating (2006)	6,832	88.03	49,650	71.95
	GCs District Heating (2007)	16,857	86.47	715,441	75.77
	GCs District Heating (2008)	20,920	84.69	1,106,439	84.46
	CV sold by GSE (2008)(B)	4,228,993	88,66	–	–
2010 (Jan-Mar)	GCs Renewables (2006)	–	–	7.300	123.65
	GCs Renewables (2007)	1,352	88.12	2.604	45.87
	GCs Renewables (2008)	3,094	87.98	20,704	73.13
	GCs Renewables (2009)	464,887	88.35	4,747,679	74.26
	GCs Renewables (2010)	18,421	85.32	296,046	81.43
	GCs District Heating (2005)	–	–	2,268	92.53
	GCs District Heating (2006)	–	–	14,191	79.32
	GCs District Heating (2007)	2,973	87.82	37,130	79.10
	GCs District Heating (2008)	14,074	87.69	178,156	77.24
	GCs District Heating (2009)	172	86.90	1,342,428	77.05

(A) The average prices of green certificates are net of VAT.

(B) Green certificates own by the GSE and sold in special sessions organised in April 2009 at a pre-set offer price defined in accordance with Law 244/07.

Source: AEEG, from GME data.

In 2009, the average sales price in the GME market, at 88.46 €/MWh, was slightly higher than the bilateral trading price (88.08 €/MWh). Liquidity in the organised market averaged out at around 22%.

In the first quarter of 2010, on the other hand, the average market price, of 88.21 €/MWh, was nearly 13 €/MWh higher than the average price of bilateral transactions. Q1 2010 also saw a drop in liquidity in the GME market, of just over 7%.

The Ministry for Economic Development's Decree of 18 December 2008 implementing Law 244/2007 introduced a number of new provisions that affected the green certificate pricing mechanism. More specifically, it envisaged that in the transitional period from 2009 to 2011, traders may ask the GSE to withdraw green certificates prior to their maturity date. The price applied would be equal to the average market price for the three-years preceding the year in which the application for withdrawal was submitted.

For applications submitted by March 2009, the price recognised by the GSE is 98.00 €/MWh (net of VAT). This corresponds to the average weighted price recorded in the three years from 2006 to 2008. For applications referring to the following year, the price of the certificates has been set at 88.91 €/MWh.

Since 2008, in accordance with Law 244/2007, the green certificates issued by the GSE have been placed on the market at a price equating to the difference between 180 €/MWh and the average annual selling price of electricity as defined by the Authority and recorded the previous year[4].

With Resolution ARG/elt 10/09 of 28 January 2009, the Authority set the average price for the sale of electricity at 91.34 €/MWh for 2008. This figure was obtained by applying the method envisaged by Law 244/2007.

As a result, in 2009 the value of green certificates available to the GSE was 88.66 €/MW €/MWh (net of VAT).

4 Under Law 244/2007, the average annual sales price for electricity is defined by the Authority in accordance with art. 13.3 of Legislative Decree 387/2003 concerning the "dedicated withdrawal" arrangements for renewable energy. Under Resolution 280/07, the price recognised for producers in "dedicated withdrawal" transactions is the price formed on the electricity market (known as the "hourly zone-level price") and paid on the basis of the individual producer's hourly injection profile.

This value, which is lower than the green certificate withdrawal price recognised by the GSE, created an anomaly in the functioning of the green certificates mechanism with reference to the obligation for 2008 (April 2008–March 2009).

For 2010, certificates available to the GSE were priced at 112.82 €/MWh. This figure is based on the average annual price of 67.18 €/MWh for the sale of electricity in 2009, as established by Resolution ARG/elt 3/10 of 25 January 2010.

Energy Efficiency Certificates Market

Energy efficiency certificates (Italian initials TEE), also known as white certificates, were introduced by the decrees issued by the Ministry for Productive Activities on 20 July 2004. These established the national quantitative targets for increased energy efficiency in the electricity and natural gas sectors for the period 2005 to 2009.

The decree issued by the Ministry for Economic Development in conjunction with the Ministry for the Environment on 21 December 2007 supplemented and amended the previous decrees of 2004. It established new national quantitative targets for energy efficiency improvements to be achieved by electricity and natural gas distributors in the period 2008-12[5]. For each of the years following 2007, these obligations apply to distributors which, at 31 December of the preceding year, had more than 50,000 consumers connected to their distribution grid.

The GME issues TEEs to distributors, their subsidiaries and energy service companies (ESCOs). TEEs are intended to certify any reduction in consumption obtained through initiatives and projects to increase energy efficiency. To perform this task, the GME organises and manages a TEE Register.

TEEs are issued on the basis of the energy savings achieved by distributors or ESCOs and notified by the Authority to the GME. Through Resolution 103/03 of 18 September 2003 as amended, the Authority has drawn up guidelines for the preparation, implementation and evaluation of the projects referred to at article 5 of both of the 2004 decrees. It has also defined the criteria and arrangements under which TEEs can be issued.

TEEs have a value of 1 toe and fall into three categories:

- type I, certifying that primary energy savings have been achieved through interventions to reduce final electricity consumption;
- type II, certifying that primary energy savings have been achieved through interventions to reduce natural gas consumption;
- type III, certifying that primary energy savings have been achieved through interventions other than those classified under types I and II.

Electricity and natural gas distributors may also achieve their energy efficiency targets by purchasing TEEs from other operators through bilateral transactions or by trading on a dedicated market organised and run by the GME. The rules for the functioning of this market were defined by the GME in agreement with the Authority.

As regards bilateral transactions, with resolution 345/07 of 28 December 2007 the Authority established that, with effect from 1 April 2008, operators eligible to operate on the TEE Register must inform the GME not just of the quantities of TEEs traded bilaterally but also of their prices.

In the course of 2009, 973,250 TEEs were traded in the organised market, most of which (65.6%) were type I.

Considering also the 1,362,064 TEEs traded in bilateral transactions, the total white certificates traded correspond to a saving of 2,335,314 toe. Liquidity on the organised market was just under 42%.

Average prices on this market (81.17 €/toe) were about 18%, or more than 12 €/toe, higher than those seen in bilateral transactions.

In the first three months of 2010, 301,024 TEEs were traded on the organised market, where the liquidity level was

5 In particular, the decree sets an overall energy efficiency improvement target in the final uses of electricity and natural gas equal to 2.2 Mtoe in 2008, 3.2 Mtoe in 2009, 4.3 Mtoe in 2010, 5.3 Mtoe in 2011 and 6.0 Mtoe in 2012.

TAB. 2.22

Results of trading in White Certificates (TEEs)

TEEs traded in toe; average price in €/toe

TRADING PERIOD	TYPE	GME MARKET TEE TRADED	GME MARKET AV. PRICE	BILATERAL TEE TRADED	BILATERAL AV. PRICE
2009	I	638,324	81.51	1,024,040	68.62
	II	285,615	80.64	256,760	66.82
	III	49,311	79.83	81,264	77.49
2010 (Jan-Mar)	I	173,554	92.79	244,166	69.40
	II	108,472	91.82	92,509	69.53
	III	18,998	94.10	7,022	74.81

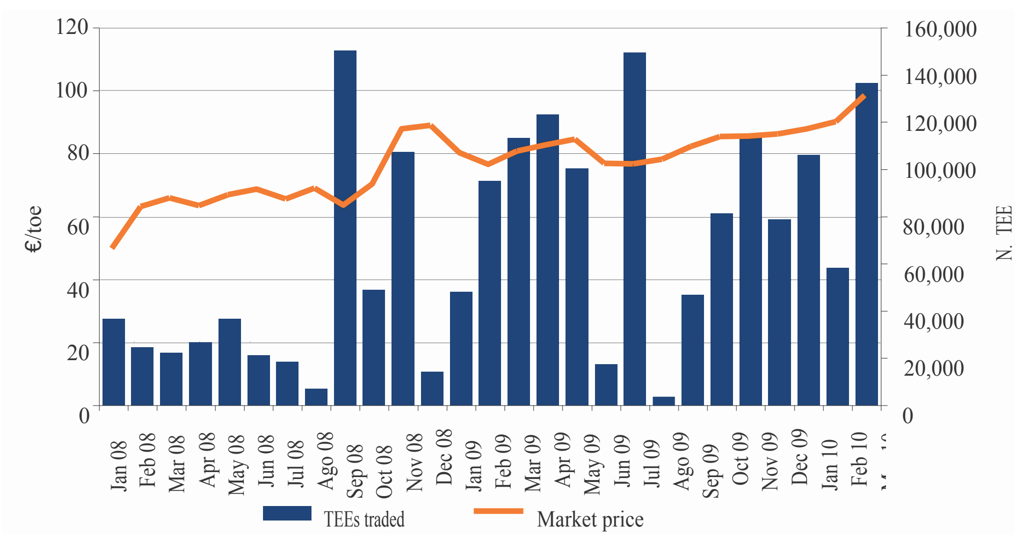
Source: AEEG, from GME data.

46.7%. The difference between the average trading price on this market and the bilateral transaction price increased further with respect to 2009, to nearly 23 €/toe (a rise of about 33%). Figure 2.22 illustrates the monthly trend in average prices of TEEs, and quantities traded, without distinction by type. Volumes traded saw a marked increase (of 89%) with respect to 2008, and a high degree of monthly variation. After a fall in June 2009, the TEEs price grew constantly, reaching a peak in March 2010.

FIG. 2.22

Prices and quantities in the White Certificates (TEE) Market

€/toe; no. of TEEs



Source: AEEG, from GME data.

Retail market

According to provisional figures published by Terna, retail electricity sales amounted to about 281 TWh in 2009 (excluding self-consumption and network losses). Table 2.23 provides a breakdown of total sales and total number of customers (estimated from the number of withdrawal points) by type of market. This classification is based on the data collected by the Authority from electricity operators: producers, protected-tariff and safeguard-service providers, wholesalers and retailers.

Notwithstanding the reduction in absolute terms of over 6 TWh with respect to 2008, the protected market as a percentage of the total was essentially unchanged on the previous year, in the order of 30%. (This figure is again based on provisional figures published by Terna and is net of self-consumption and losses). The safeguard service was used by about 130,000 consumers and amounted to around 2.6% of total sales.

TAB. 2.23

Retail market by market and customer type, 2009

Net of self-consumption and losses; volumes in GWh, withdrawal points (1000s)

	VOLUMES	WITHDRAWAL POINTS(A)
Enhanced protection market	**84,065**	**31,637**
Domestic	57,302	26,453
Non-domestic	26,764	5,184
Safeguard market	**7,225**	**130**
Free market(B)	**179,942**	**4,266**
Domestic	5,089	1,828
Non-domestic	174,853	2,439
TOTAL MARKET	**271,233**	**36,033**

(A) Withdrawal points are calculated using the per day criterion.
(B) The data for the free market are provisional and cover about 95% of total volumes.
According to Terna's provisional data, total consumption (net of self-consumption and losses) amounted to 281 TWh.

Source: AEEG, from data provided by operators.

Once again, the Enel group was the main operator in the retail segment, with an overall market share of approximately 46%. This mainly consisted of sales to domestic customers (84.5% of the segment), with sales to non-domestic customers accounting for just over 34% of that segment. The Edison group ranked second, with an overall share of 8% made up largely of sales to non-domestic medium- and high-voltage customers. These were followed by the Electrabel/Acea group, with just under 5%, and E.On, which reached a 4.3% market share almost entirely through sales to non-domestic customers.

TAB. 2.24

Sales to retail market by corporate group and customer type, 2009

GWh

COMPANY	DOMESTIC CUSTOMERS	LV NON-DOMESTIC			TOTAL
		LV	MV	HV & VHV	
Enel	52,749	40,730	16,65	14,366	124,495
Edison	289	2,877	11,87	6,690	21,728
Electrabel/Acea	3,053	2,983	4,892	2,421	13,349
E,On	53	2,235	6,699	2,617	11,605
A2A	1,825	2,568	4,284	682	9,358
Eni	216	484	4,366	3,919	8,984
Sorgenia	347	5,169	3,287	176	8,979
Hera	437	2,068	4,077	253	6,834
Avelar Energy	4	986	3,296	2,357	6,643
Iride	834	915	1,732	893	4,374
Axpo Group	–	271	2,343	1,303	3,917
Repower	–	1,439	1,741	4	3,183
Modula	7	875	930	1,081	2,893
Exergia	0	704	1,948	123	2,775
Dolomiti Energia	447	961	1,059	19	2,486
Assoutility	–	35	2,128	172	2,334
Telecom Italia	–	700	1,413	–	2,113
C,I,E,	1	680	1,319	–	2,000
Agsm Verona	277	480	947	9	1,714
Egea	13	229	1,321	134	1,697
Other operators	1,839	7,532	17,81	2,583	29,771
ALL OPERATORS	**62,391**	**74,919**	**94,12**	**39,801**	**271,233**

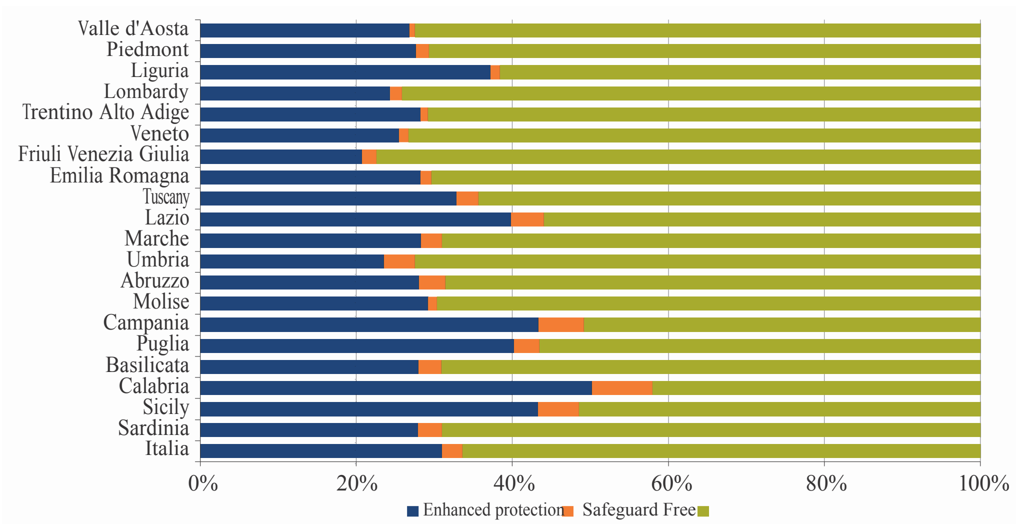
Source: AEEG, from operators' declarations.

Fig. 2.23 shows a breakdown of the different types of market at the regional level. The free market segment is larger in northern regions while in most of the southern regions the presence of the protected and safeguard segments is higher than the national average. Calabria has the lowest degree of market opening, with sales on the free market accounting for just over 40% of total sales.

FIG. 2.23

Sales to the retail market by region and market type, 2009

Percentage breakdown[(A)]



Source: AEEG, from operators' declarations.

Enhanced protection service

The enhanced protection (protected tariffs) service is intended for low-voltage domestic customers and small businesses who have not entered into a supply contract in the free market. The service is provided by dedicated retailers or distributors with fewer than 100,000 customers connected to their network, on the basis of prices and commercial quality conditions recommended by the Authority.

In 2009, sales to protected-tariff users amounted to around 84 TWh for a total of over 31 million delivery points, a reduction of 6% on 2008. 68% of the volumes (about 57 TWh) were purchased by domestic customers who, in numerical terms, represent 84% of the total protected market (over 26 million users) (Tab. 2.25).

Two-tier tariffs were applied to about 183,000 domestic customers, 14% more than in 2008. The Authority has established that, starting from 1 July 2010, two-tier tariffs will be applied progressively and automatically to consumers using the protected service and equipped with the new reprogrammed electronic meters.

TAB. 2.25

Enhanced protection service by type of customer, 2009
Volumes in GWh; number of withdrawal points (1000s)

CUSTOMER TYPE	VOLUMES	NO. OF WITHDRAWAL POINTS(A)
Resident domestic up to 3 kW	**44,792**	**19,772**
- single-tier	44,416	19,654
- two-tier	376	118
Resident domestic over 3 kW	**6,311**	**1371**
- single-tier	6,100	1,325
- two-tier	211	46
Non-resident domestic over 3 kW	**6,199**	**5,310**
- single-tier	6,159	5,290
- two-tier	40	20
Public lighting	**781**	**37**
- single-tier	778	37
- multi-tier	3	0
Other uses	**25,983**	**5,147**
- single-tier	9,921	2,210
- two-tier	30	2
- multi-tier	16,032	2934
TOTAL	**84,065**	**31,637**

(A) Withdrawal points are calculated using the per day criterion

Source: AEEG, from data provided by operators.

89% of the protected domestic market is made up of resident customers, of whom about 88% are customers connected at capacity of up to 3 kW. The corresponding figures for withdrawal points were, respectively, 80% and 93%.

Domestic customers' average annual consumption was about 2,170 kWh. For resident customers this figure can be broken down into around 2,270 kWh for connections of up to 3 kW and 4,600 kWh for those over 3 kW, while for non-resident consumers the figure is about 1,170 kWh. 61% of resident customers with a connection capacity of up to 3 kW belong to the first three consumption categories (consumption of less than a 2,500 kWh/year), while 34% of those with capacity of more than 3 kW belong to the last two consumption classes (consumption above 5,000 kWh/year).

As for non-residents (consumers with second homes), 63% fall into the first category (consumption below 1,000 kWh/year) (Tab. 2.26).

TAB. 2.26

Sales to domestic customers by customer type and consumption category, 2009

Volumes in GWh; number of withdrawal points in 1000s

CUSTOMER TYPE	VOLUMES	NO. OF WITHDRAWAL POINTS(A)
Resident domestic up to 3 kW	**44,792**	**19,772**
0-1,000 kWh	1,552	3,008
1,000-1,800 kWh	6,577	4,611
1,800-2,500 kWh	9,690	4,509
2,500-3,500 kWh	13,341	4,619
3,500-5,000 kWh	9,876	2,428
5,000-15,000 kWh	3,528	595
> 15,000 kWh	228	1
Resident domestic over 3 kW	**6,310**	**1,371**
0-1,000 kWh	27	53
1,000-1,800 kWh	119	82
1,800-2,500 kWh	278	128
2,500-3,500 kWh	775	256
3,500-5,000 kWh	1,619	384
5,000-15,000 kWh	3,183	455
> 15,000 kWh	311	13
Non-resident domestic	**6,199**	**5,310**
0-1,000 kWh	1,159	3,358
1,000-1,800 kWh	1,163	859
1,800-2,500 kWh	880	416
2,500-3,500 kWh	968	329
3,500-5,000 kWh	852	207
5,000-15,000 kWh	935	133
> 15,000 kWh	241	8
TOTAL DOMESTIC	**57,302**	**26,453**

(A) Withdrawal points are calculated using the per day criterion.

Source: AEEG, from data provided by operators.

Table 2.27 shows volumes (around 26 TWh) and withdrawal points (more than 5 million) with respect to other uses, broken down by consumption class. About 79% of non-domestic customers (excluding public lighting) belong to the first consumption class (< 5 MWh/year), for a corresponding volume of consumption equating to about 19% of overall sales.

TAB. 2.27

Sales to non-domestic customers (other uses) by consumption category, 2009

Volumes in GWh; number of withdrawal points in 1000s

CONSUMPTION CATEGORY	VOLUMES	NO. OF WITHDRAWAL POINTS(A)
< 5 MWh	4,882	4,084
5-10 MWh	3,455	494
10-15 MWh	2,285	187
15-20 MWh	1,823	106
20-50 MWh	6,159	203
50-100 MWh	3,586	53
100-500 MWh	3,430	20
500-2,000 MWh	320	0
2,000-20,000 MWh	43	0
TOTAL OTHER USES	**25,983**	**5,147**

(A) Withdrawal points are calculated using the per day criterion.

Source: AEEG, from data provided by operators.

Although about 150 operators are active in the protected market, the segment is highly concentrated. Enel Servizio Elettrico continues to be the main operator, with a market share of about 84%, followed by AceaElectrabel Elettricità (5.3%), A2A Energia (3.2%) and Iride Mercato (1.4%). Other suppliers have shares of less than 1%.

TAB. 2.28

Main operators providing the enhanced protection service, 2009

Volumes in GWh; percentage share

COMPANY	VOLUMES	% SHARE
Enel Servizio Elettrico	70,597	84.0%
AceaElectrabel Elettricità	4,476	5.3%
A2A Energia	2,657	3.2%
Iride Mercato	1,197	1.4%
Hera Comm	662	0.8%
Asm Energia E Ambiente	537	0.6%
Trenta	524	0.6%
Azienda Energetica Etschwerke	413	0.5%
AGSM Energia	412	0.5%
Enia Energia	331	0.4%
Acegas Aps Service	314	0.4%
A.I.M. Energy	192	0.2%
Vallenergie	179	0.2%
Other operators	1,573	1.9%
TOTAL	**84,065**	**100.0%**

Source: AEEG, from data provided by operators.

Free market

Electricity prices in Milan and district

With a view to promoting transparency in the contractual conditions applied and monitoring the functioning of the free market in electricity, Milan Chamber of Commerce has introduced a quarterly survey of the energy prices applied to micro, small and medium-sized enterprises in the Milan area. In this, it enjoys the support of Unioncamere and technical coordination by Ricerche per l'economia e la finanza (ref.).
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Milan Chamber devotes a special section in its wholesale price surveys to the prices applied in the most widespread forms of energy contract.

This "market report" is published on a regular basis on the dedicated portal. The operation was preceded by a survey to identify the contract types most commonly found in Milan and is accompanied by periodic checks on energy needs in enterprises in the province. SOCIETÀ

The surveys focus on the economic conditions applied by suppliers in the most common types of contracts in the free market with respect to certain standard customer profiles. More specifically, they examine the energy component price, defined as franco centrale (ex power station), net of network losses. This price includes generating costs, costs incurred by suppliers in balancing the electricity actually taken up by users and that injected to the grid (imbalance costs), as well as the costs incurred by suppliers to cover any penalties under the Community law governing polluting emissions (CO2 charges). The survey excludes all other *electricity cost components, i.e., retail marketing and sales costs, passing costs such as dispatching charges, transport charges and "improper" costs. It also excludes taxes (excise, provincial surcharges and VAT). It is conducted ex post, which means that it refers to the prices actually paid for active supplies.*

The standard enterprise profiles currently surveyed are six in number and correspond to a combination of the most widespread contractual clauses. They include 2 annual consumption categories: up to 300 MWh/year and from 301 to 1.200 MWh/year; two contract durations: 12 and 24 months; two price types: single-tier (i.e. not-differentiated by hourly bands) and multi-tier (with 3 prices per band). For each profile, two types of contract are surveyed: fixed- and variable-price (indexed through price formulae or linked, typically with a percentage discount, to the enhanced protection regime). The questionnaires and responses are checked regularly with suppliers and representatives of consumers' associations and consortia operating in the Milanese market, both to ensure they are representative and to incorporate any changes in market practices.

By publishing the Market Report on a regular basis, it is hoped that a number of goals will be achieved. The initiative makes it possible to obtain price references for the most commonly used contractual models and to quantify price differences linked to:

– contract duration
– differences in the arrangements for adjusting charges (fixed and variable)
– the distribution of charges (by band or otherwise)
– higher or lower annual consumption levels (two consumption bands).

It also provides an opportunity to assess how the free market is evolving and a means of quantifying, ex post, the cost savings that enterprises can achieve through access to the free energy market.

The basic goal of the project – currently being developed in other Chambers of Commerce too – is to foster the dissemination of knowledge that can be used to better understand the workings of the free market. It does so by facilitating access to the user categories most deserving of protection because most exposed to problems arising from information imbalances, such as micro- and small businesses.

The market report's informational scope

The attached table provides information on the most widespread contract types activated since 1 January 2010 in Milan and its province.

The first thing to note is that a positive difference, of several €/MWh, exists between fixed- and variable-price contracts, to the benefit of the latter. In January 2010, fixed-price contracts were, relatively speaking, less economically advantageous than variable-price contracts. This can be interpreted in light of expectations that variable prices will increase. In other words, the difference conveys the message that, on average, the market foresees a future increase in fossil fuel prices and therefore in thermoelectric generation costs.

It is important to remember that, other conditions being equal, the price difference between fixed- and variable-price contracts also incorporates an "insurance" element. Suppliers undertake to keep prices constant for the entire duration of the contract, even in the presence of changes in generating costs.

If, for the purposes of this survey, we take price types (single-tier or multi-tier) as being equal, higher charges can be observed for 24-month as opposed to 12-month contracts. Longer contract duration corresponds, therefore, with higher unit charges.

This finding suggests that in a highly variable market context, a longer contract duration involves a longer commitment on the supplier's part to keep prices unchanged, even if generating costs should change. The distance between the prices charged for 12- and 24-month contracts therefore counteracts this "insurance" function.

And again, taking price-type and contract duration as being equal, higher consumption profiles present slightly lower unit costs, which suggests we are seeing moderate quantity discounts.

The scope of the information contained in the Market Report is such that comparisons can be made with the economic conditions up-dated by the Authority on a quarterly basis and applied to companies with low voltage supplies, sales of less than 10 million euros per year and with fewer than 50 employers, and which have not selected their supplier on the free market. It is possible, therefore, to draw some conclusions as to the relative economic advantages, on activation of supply, of the free market and the protected tariff system for low-voltage business customers eligible for the protected service. For these micro- and small enterprises, the January 2010 survey reveals a situation where costs for fixed-price, single-tier contracts for supplies of up to 300 MWh/year are essentially in line with the protected service conditions in force for Q1 2010.

At the outset, the charges for single-tier but variable-price contracts for electricity supplies to the same market segment indicate, for the month of January 2010 only, a discount of several euros per MWh with respect to the conditions applied for the protected service. A definitive balance as to the economic advantages of these contracts can only be drawn up ex post, that is, by considering price developments over their entire duration.

CONSUMPTION CLASSES (MWh/YEAR)	VOLTAGE	DURATION	TYPE	FIXED PRICE €/MWh			VARIABLE PRICE [B] €/MWh		
				F1	F2	F3	F1	F2	F3
Up to 300	LV	12 months	Single-tier		85.24			80.73	
Up to 300	LV	24 months	Single-tier		87.83			n.a.	
Up to 300	LV	12 months	Multi-tier	103.18	80.04	59.33	103.39	77.98	56.44
Up to 300	LV	24 months	Multi-tier	105.85	85.15	60.52	n.a.	n.a.	n.a.
From 301 to 1.200	LV or MV	12 months	Multi-tier	102.87	79.79	58.19	98.05	74.65	52.25
From 301 to 1.200	LV or MV	24 months	Multi-tier	105.60	84.44	59.06	n.a.	n.a.	n.a.

(A) Includes, in addition to the electricity charge, imbalance and CO2 costs
(B) Price at first month of supply, January 2010.

Electricity prices in Milan and its province, January 2010

From producer/wholesaler/retailer to non-domestic user; main price of the "ex power-station" electricity component"[A] for 12-24 month contracts activated with effect from 1 January 2010

Electricity sales in the free market in 2009, calculated by subtracting sales under the safeguard service from Terna's provisional figure for the free market, amounted to 189 TWh, a decrease of over 3% on 2008. In Table 2.29 the data collected by the Authority, covering about 95% of Terna's provisional total, are broken down by type of customer. Just under 95% of volumes concerned "other uses" (i.e., uses other than domestic and public lighting) for about 3 million withdrawal points (70% of the total).

In 2009, electricity was supplied to about 1,800,000 domestic customers in the free market for a total of 5.1 TWh. Around 46% of sales were to customer categories consuming over 3,500 kWh/year (Tab. 2.30).

TAB. 2.29

Free market by customer type, 2009

Volumes in GWh; number of withdrawal points in 1000s(A)

CUSTOMER TYPE	VOLUMES	NO. OF WITHDRAWAL POINTS(B)
LV	**50,913**	**4,184**
Domestic	5,089	1,828
Public lighting	4,279	187
Other uses	41,545	2,169
MVT	**89,419**	**82**
Public lighting	324	1
Other uses	89,095	81
HV and VHV	**39,610**	**1**
Other uses	39,610	1
TOTAL	**179,942**	**4,266**

(A) The data for the free market are provisional and cover about 95% of total volumes

(B) Withdrawal points are calculated using the per day criterion.

Source: AEEG, from data provided by operators.

TAB. 2.30

Free market: domestic by consumption class, 2009

Volumes in GWh; number of withdrawal points in 1000s(A)

CONSUMPTION CATEGORY	VOLUMES	NO. OF WITHDRAWAL POINTS(B)
< 1,000 kWh	132	174
1,000-1,800 kWh	556	363
1,800-2,500 kWh	762	343
2,500-3,500 kWh	1,319	449
3,500-5,000 kWh	1,299	331
5,000-15,000 kWh	976	166
> 15,000 kWh	46	2
TOTAL	**5,089**	**1,828**

(A) The data for the free market are provisional and cover about 95% of total volumes

(B) Withdrawal points are calculated using the per day criterion.

Source: AEEG, from data provided by operators.

As for non-domestic customers, sales in volume terms were concentrated in the highest consumption categories. Approximately 0.4% of customers consumed more than 2,000 MWh a year, for a total of 96 TWh (around 55% of total sales in the market segment in question) while just under half of customers consume less than 5 MWh per year (Tab. 2.31).

TAB. 2.31

Free market: non-domestic by consumption class, 2009

Volumes in GWh; number of withdrawal points in 1000s(A)

CONSUMPTION CATEGORY	VOLTAGE LEVEL	VOLUMES	NO. OF WITHDRAWAL POINTS(B)
< 5 MWh	LV	2,270	1,158
5-10 MWh	LV	2,527	358
10-15 MWh	LV	2,260	187
15-20 MWh	LV	2,108	124
< 10 MWh	MV	16	3
10-20 MWh	MV	28	2
< 20 MWh	HV and VHV	0	0
20-50 MWh	All	9,853	320
50-100 MWh	All	8,870	132
100-500 MWh	All	23,251	115
500-2,000 MWh	All	27,578	30
2,000-20,000 MWh	All	48,545	10
20,000-50,000 MWh	All	13,700	0
50,000-70,000 MWh	All	3,724	0
70,000-150,000 MWh	All	6,759	0
> 150,000 MWh	All	23,362	0
TOTAL		**174,853**	**2,439**

(A) The data for the free market are provisional and cover about 95% of total volumes

(B) Withdrawal points are calculated using the per day criterion.

Source: AEEG, from data provided by operators.

If we consider the free market as a whole, in 2009 the main operator in sales terms was ENEL, whose market share remained at just under 27%, essentially unchanged with respect to 2008. The ten leading operators account for about 72.5% of the market in terms of volumes sold.

TAB. 2.32

Main operators on free market, 2009

Volumes in GWh; percentage share(A)

GROUP	VOLUMES	%SHARE
Enel	48,229	26.8
Edison	21,728	12.1
E.On	11,605	6.4
Eni	8,984	5.0
Sorgenia	8,979	5.0
Electrabel/Acea	8,873	4.9
Avelar Energy	6,643	3.7
A2A	6,161	3.4
Hera	5,294	2.9
Axpo Group	3,917	2.2
Other operators	49,530	27.5
TOTAL OPERATORS, FREE MARKET	**179,942**	**100.0**

(A) The data for the free market are provisional and cover about 95% of total volumes

Source: AEEG, from data provided by operators.

Safeguard service

All customers not eligible for access to the protected-tariff service and who, even temporarily, are without an electricity supply contract in the free market, are eligible for the safeguard service. Since 1 May 2008, this service has been provided by retail companies selected by auction.

In 2009, the safeguard service involved about 130,000 withdrawal points calculated using a per-day criterion. Electricity withdrawals amounted to about 7.2 TWh.

5.7% of sales were for public lighting and the remainder for other industrial/commercial uses, the lion's share being for medium-voltage connections (65% of total sales) (Tab. 2.33).

TAB. 2.33

Safeguard service by customer type

Volumes in GWh

CUSTOMER TYPE	VOLUMES	NO. OF WITHDRAWAL POINTS[(A)]
LV	**2,332**	**111,757**
Public lighting	370	14,963
Other uses	1,962	96,795
MV	**4,702**	**18,143**
Public lighting	44	220
Other uses	4,658	17,923
HV and VHV	**191**	**91**
Other uses	191	91
TOTAL SAFEGUARD	**7,225**	**129,991**

(A) Withdrawal points are calculated using the per day criterion.

Source: AEEG, from data provided by operators.

A geographical breakdown of sales shows that the main regions in terms of energy supplied through the safeguard service are Campania, Lombardy and Lazio, all with sales of over 900 GWh.

TAB. 2.34

Safeguard service by Region, 2009

Volumes in GWh

CONSUMPTION CATEGORY	VOLUMES	NO. OF WITHDRAWAL POINTS[(B)]
Valle d'Aosta	5	55
Piedmont	356	7,038
Liguria	70	2,347
Lombardy	918	15,209
Trentino Alto Adige	53	1,672
Veneto	330	7,851
Friuli Venezia Giulia	152	2,292
Emilia Romagna	324	7,662
Tuscany	482	10,792
Lazio	911	9,062
Marche	193	3,248
Umbria	201	2,531
Abruzzo	186	4,639
Molise	16	818
Campania	936	13,422
Puglia	452	8,975
Basilicata	68	1,357
Calabria	416	7,438
Sicily	853	17,312
Sardinia	304	6,272
TOTAL	**7,225**	**129,991**

(A) Withdrawal points are calculated using the per day criterion.

Source: AEEG, from operators' declarations.

Prices and tariffs

Tariffs for infrastructure use

With Resolution ARG/elt 203/09 of 29 December 2009, the Authority provided for the annual adjustment of electricity tariffs to cover network infrastructure costs (transmission services on the very high voltage network, local distribution and metering). Tariffs for these services were subjected to annual review. The latest one envisaged:

- a reduction in real terms of the tariff component remunerating operating costs, under the price cap mechanism;
- an adjustment of the remaining tariff components covering depreciation and return on invested capital, to take into account new investments made in the interests of security, competition and service quality.

The average national tariff covering transmission, distribution and metering costs for 2010 increased – overall – by 3.0% with respect to 2009, i.e., from 2.188 c€/kWh to 2.253 c€/kWh.

TAB. 2.35

Average annual tariffs for the transmission, distribution and metering services

c€/kWh

YEAR	TRANSMISSION	DISTRIBUTION	METERING	TOTAL
2010	0.385	1.597	0.271	2.253
2009	0.363	1.547	0.278	2.188
2008	0.345	1.534	0.273	2.152
Difference 2010-2009	0.022	0.050	–0.007	0.065
% change 2010-2009	6.1%	3.2%	–2.5%	3.0%

TAB. 2.36

Transmission and distribution services: Tariffs by customer type

c€/kWh

CUSTOMER TYPE	TRANSMISSION AND DISTRIBUTION 2008	2009	2010	DIFFERENCE 2010-2009
LV domestic uses	3.417	3.505	3.616	0.111
LV public lighting	1.706	1.751	1.813	0.062
LV other uses	2.726	2.798	2.895	0.097
MV public lighting	1.072	1.104	1.140	0.036
MV other uses	1.133	1.166	1.214	0.048
HV	0.446	0.465	0.493	0.028
VHV > 220 kV	0.405	0.424	0.448	0.024

TAB. 2.37

Metering service: tariffs by customer type
c€/kWh

CUSTOMER TYPE	METERING 2008	2009	2010	DIFFERENCE 2010-2009
LV domestic uses	0.926	0.946	0.922	–0.024
LV public lighting	0.065	0.066	0.065	–0.001
LV other uses	0.287	0.290	0.283	–0.007
MV public lighting	0.061	0.063	0.062	–0.001
MV other uses	0.029	0.029	0.029	–
HV	0.005	0.005	0.005	–
VHV > 220 kV	0.001	0.001	0.001	–

Enhanced protection service

Procurement by Single Buyer

Following the full liberalisation of the electricity sales market on 1 July 2007, in accordance with Law 125 of 3 August 2007 confirming Decree Law 73 of 18 June 2007 the *Acquirente Unico* (Single Buyer) is the operator responsible for procuring electricity for customers using the “protected-tariff service”. This is intended for domestic customers and small businesses that do not have access to a retailer on the free market.

Customers in this position who are still not eligible for the protected-tariff service are covered by the “safeguarded service” provided by a sales company selected through competitive tender. In performing the functions within its remit, the Single Buyer has the task of procuring electricity while minimising the costs and risks inherent to the various methods of procurement to which it can resort.

Table 2.38 shows the Single Buyer’s procurement volumes for January-December 2009. As can be seen from the table, for about 25% of its supply requirements the Single Buyer has entered into contracts outside the bidding system.

As regards purchases in the Day-Ahead Market (MGP), 42% were hedged against price risks through contracts for differences and through an amount of electricity corresponding to “CIP6 production capacity” (i.e., capacity under resolution 6 of the Interministerial Price Committee (CIP) of 29 April 1992).

TAB. 2.38

Single Buyer – Procurement volumes, 2009

GWh, gross of network losses

ELECTRICITY PURCHASES	F1	F2	F3	TOTAL
Outside the offer system	9,734	5,172	9,338	24,244
of which				
- annual imports	1,011	687	1,225	2,923
- long-term imports	1,676	1,232	2,347	5,255
- bilateral contracts	7,047	3,253	5,766	16,066
Day-Ahead Market	27,548	20,594	22,562	70,704
of which				
- contracts for differences	9,774	4,538	8,036	22,348
- CIP 6	2,403	1,766	3,364	7,533
- purchased at PUN	15,371	14,290	11,162	40,823
Adjustment as per Res. ARG/elt 104/09	139	177	135	451
Consumption unit imbalance(A)	–820	600	949	729
TOTAL	**36,601**	**26,543**	**32,984**	**96,128**

(A) For the sake of simplicity, the sign agreed and established by resolution 111/06 of 9 June 2006 as supplemented and amended was not observed

Source: AEEG, from Single Buyer data

The electricity adjustment envisaged by Resolution ARG/elt 104/09 of 28 July 2009 concerns the fact that, with reference to June 2009, after errors were found in the coefficients determined for the distribution of withdrawals, Terna adopted an extraordinary adjustment procedure applicable to dispatching users.

Under this procedure the single Buyer should pay Terna if positive, or receive from Terna if negative, an extraordinary equalisation fee that is the direct opposite of the sum of the extraordinary adjustment charges payable by other dispatching users.

The quantity of imbalance electricity allocated to the Single Buyer as user of the consumption unit dispatching service was lower than the 2008 level and corresponded to about 0.8% of the requirement.

Table 2.39 shows prices in the Single Buyer's portfolio not subject to the price risk associated with price volatility on the Power Exchange.

With reference to 2010[6], the amount of electricity purchased in the MGP met about 59% of the Single Buyer's requirements.

TAB. 2.39

Percentage Composition of the Single Buyer's Portfolio, 2009

Incidence of supply sources not subject to price risk on total requirements January–December 2009

	F1	F2	F3	TOTAL
CIP6	7%	7%	10%	8%
Bilateral contracts	19%	12%	17%	17%
Imports	7%	7%	11%	9%
Contracts for differences	27%	17%	24%	23%

Source: AEEG, from Single Buyer data

6 The figures for 2010 refer to the information available at March.

A portion of the Single Buyer's portfolio is covered by contracts for differences hedging against the risk of price volatility in electricity purchased on the MGP. For 2010 it is envisaged that this should refer to:

- the electricity corresponding to the CIP6 production capacity allocated to the Single Buyer in 2010;
- the capacity underlying the contract for the sale of virtual production capacity (VPP contract) for 2010, as drawn up by the Single Buyer and ENEL Produzione.

For 2010, the Single Buyer called a number of auctions for physical bilateral contracts to be drawn up. The capacity allocated individually in each auction is shown in table 2.40, which also shows a breakdown of baseload and peakload contracts.

TAB. 2.40

Quantities allocated to bilateral contracts, 2010

DATE	MW	PRODUCT
12/12/2007	500	*Baseload*
20/12/2007	100	*Baseload*
24/11/2008	500	*Baseload*
	355	*Peakload*
09/12/2008	300	*Baseload*
	270	*Peakload*
22/05/2009	61	*Baseload*
04/06/2009	200	*Baseload*
11/06/2009	46	*Baseload*
02/07/2009	200	*Baseload*
09/07/2009	200	*Baseload*
25/09/2009	400	*Baseload*
	400	*Peakload*
02/10/2009	255	*Baseload*
	630	*Peakload*

Source: AEEG, from Single Buyer data

As regards the settlement price for individual bilateral contracts, in the auction of 20 December 2007 prices were indexed to Brent, while for all other auctions a fixed price was envisaged. The Single Buyer had entered into a number of contracts as the outcome of an auction on 19 September 2007. Under these, for 2010 it allocated a constant capacity of 155 MW for each hour of the year.

For these contracts, the Single Buyer exercised its right of withdrawal. As a consequence, it will be required to pay counterparties a fee, for each month of 2010, equal to 50% of the difference, if positive, between the PUN and the supply price, multiplied by the electricity covered by the contract.

To the electricity resulting from the allocations shown in Table 2.40 should be added 381 GWh of electricity referring to products traded on the MTE operated by the GME.

Table 2.41 shows, with respect to annual import contracts, the capacity allocated individually in each auction called by the Single Buyer.

TAB. 2.41

Quantities allocated to import contracts, 2010

AUCTION	MW	PRODUCT	BORDER	DURATION
Annual auction(A)	7	*Baseload* 29 December	Switzerland	1 January - 31 December
	25		France	
	143	*Baseload* 5 January 2010	Switzerland	
	175		France	

(A) Annual products may be subject to scheduled interruptions for network maintenance

Source: AEEG, from Single Buyer data

To the capacity awarded through these auctions, a further 14 GWh approximately should be added, referring to an import contract signed by the Single Buyer for the supply of this amount of electricity and the corresponding transmission capacity for the period 12-31 January 2010.

Finally, tab. 2.42 shows the estimated supply volumes and corresponding pricing arrangements for 2010.

TAB. 2.42

Single Buyer's Procurement Forecast for 2010

SOURCE	DESCRIPTION QUANTITY	EST. QUANTITY FOR 2010 (GWh)	% OF SINGLE BUYER'S TOTAL REQUIREMENT	PRICE
Annual imports	Capacity allocated in the auctions called by the Single Buyer for 2010	1,991	2.2	Defined in the contract
Long-term imports	600 MW with reference to the Swiss border	5,256	5.9	59.5 €/MWh, corresponding to the maximum price envisaged by decree of 18 December 2009 (up-dated quarterly in accordance with Resolution ARG/elt 194/09 of same date)
Bilateral contracts	Capacity allocated in the auctions called by the Single Buyer for 2010	29,759	33.4	Defined in the contract
Power Exchange (Day-Ahead Market)	Remaining portion to meet consumers' demand	52,235	58.5	PUN
Of which				
CIP6 bands	17% of the CIP6 bands allocated will be made available to the Single Buyer	3,878	4.3	57 €/MWh, corresponding to the maximum price envisaged by decree of 27 November 2009 (up-dated quarterly in accordance with Resolution ARG/elt 9/10 of 3 February 2010)
Contracts for differences	Capacity allocated as result of virtual production capacity (VPP) sales contracts	114	0.1	Prices based on auction award price
	TOTAL REQUIREMENT	**89,241**	**100.0**	

Source: AEEG, from Single Buyer data

Prices based on auction award price

Electricity and inflation

As described in detail in Chapter 1 of this Volume, from early 2009 the international prices of oil and oil products began to rise again, bringing an end to the steep downwards trend seen in the second half of 2008. From 40 $/barrel in December 2008, the price of Brent crude had returned to 75 $/barrel by the end of 2009, i.e., to the levels seen in October of the previous year. The contemporaneous rise in the value of the euro against the US dollar (by 8.7% in the period under consideration) made it possible to contain the growth (measured for December 2009 against December 2008) of the oil price in euros to 68.6% compared with 84% for the dollar price.

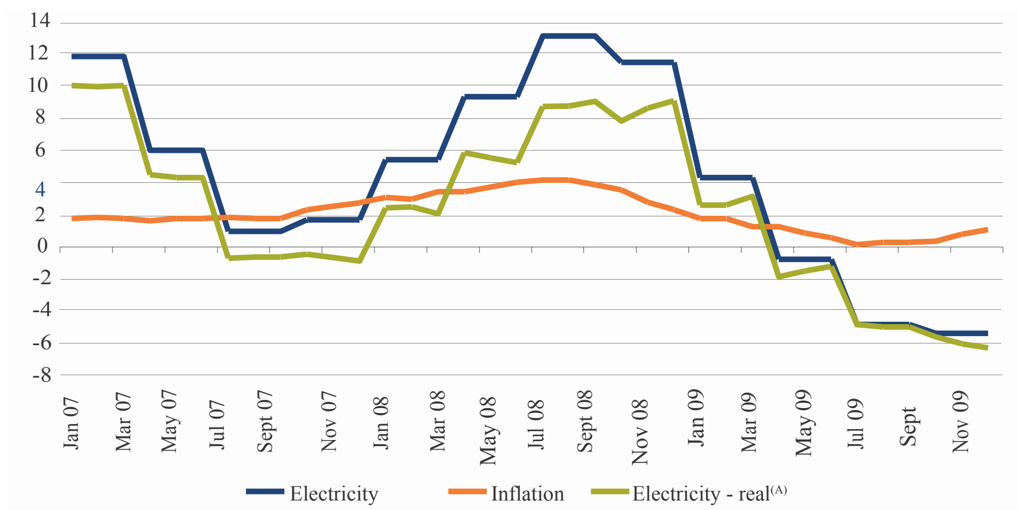
In the face of these international trends, the electricity price measured by the National Statistics Institute (ISTAT) as part of the national consumer price basket for the entire population (NIC)[7] continued this downwards trend until summer 2009, to then remain stable until the end of the year.

While in 2008 it had risen constantly – following the oil price trend but with the usual timelags as a result of indexation mechanisms – the inflation rate measured on electricity prices saw an abrupt slowdown that started in autumn 2008 and continued throughout 2009 (Fig. 2.24).

FIG. 2.24

General inflation and electricity inflation, 2007- 2009

YoY change in consumer price indices for entire population and in electricity at nominal and real prices



(A) Ratio of electricity price index to general index (excluding tobacco products).

Source: Calculations from ISTAT data, consumer price indices for entire population – national indices.

From the 13% reached in July 2008, the electricity inflation rate fell and indeed zeroed out in April 2009, falling to negative figures (–5.5%) by year-end. Over the year, the electricity price for Italian households as measured by ISTAT fell by 1.9% in 2009, after growing by 9.7% the previous year.

Since general price levels also grew in the meantime, by 3.3% in 2008 and 0.7% in 2009, the rise in the electricity price for Italian households in 2008 was actually lower if calculated in real terms (6.2%). The fall in 2009 was even more notable in real terms, at a negative 2.6%.

7 More precisely, in the national basket of consumer prices for the full population, ISTAT measures the price of electricity under the “housing costs” category. The weight of the elementary electricity index in the basket – net of tobacco products – rose from 1.2% in 2008 to 1.27% in 2009 and 1.31% in 2010.

Electricity price trends in Italy can also be compared with those of the main European countries, using Eurostat's Harmonised Indices of Consumer Prices (HICP) (Fig.2.25).

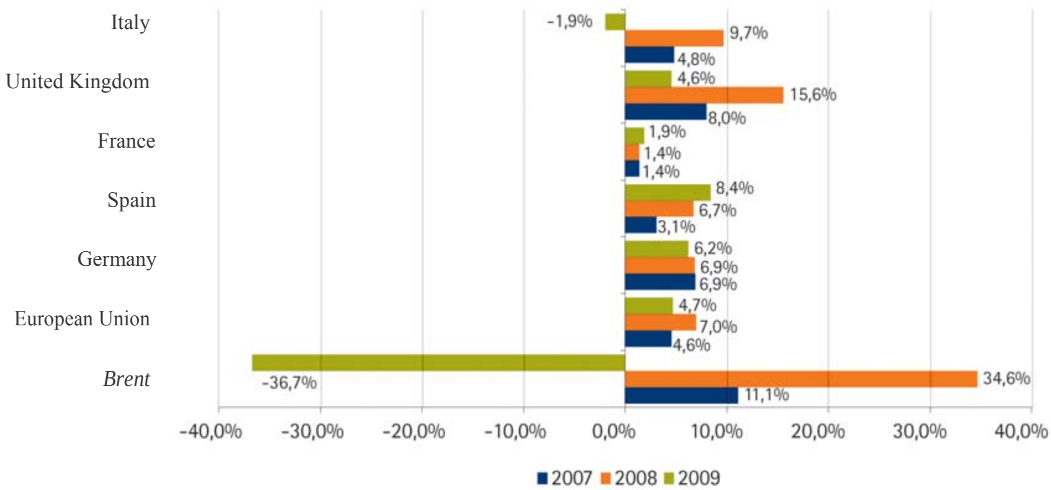


FIG. 2.25

Changes in electricity price in main European countries

% changes on previous year

Source: AEEG, from Eurostat data; Harmonised Indices of Consumer Prices.

With a fall of 1.9%, the Italian price performed better in 2009 than prices in the other countries considered, which saw increases of varying magnitudes. With the European average price (27 countries) growing by 4.7%, the smallest rise, of 1.9%, was seen in France.

The UK price grew in line with the European average, while German and Spanish consumers saw increases of 6.2% and 8.4% respectively.

In the previous two years, by contrast, the Italian price performed more poorly or in line with prices in the other countries considered. In 2007, the Italian price rise, of 4.8%, was similar to that seen in the other countries of Europe, i.e., 4.6%. In 2008, however, the Italian result was one of the worst: the 9.7% increase seen in our country was exceeded only by the UK, at 15.6%

More generally, if we observe the corresponding growth rates for the oil price, Italian electricity price trends seem much more closely correlated to trends in the Brent price than are those seen in the other European countries. This reflects the relatively higher weight of thermoelectric generation in Italy compared with other electricity production sources.

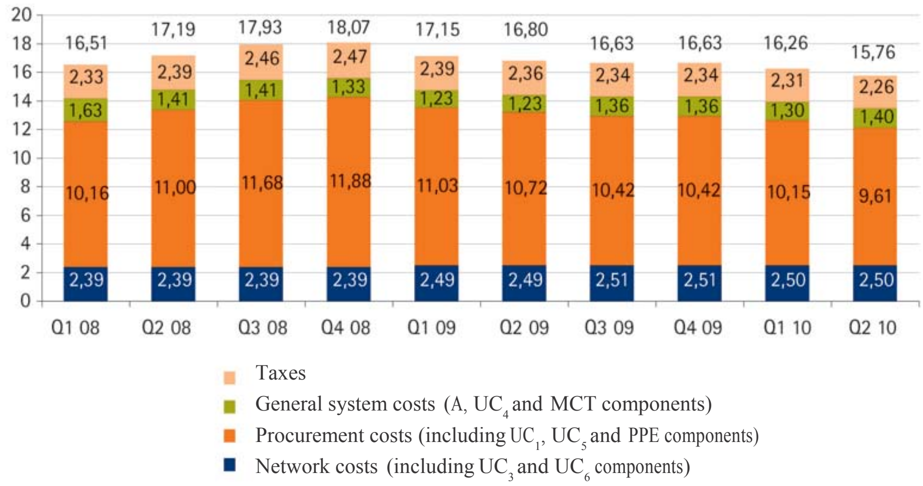
Enhanced protection service: economic conditions

The trend in the ISTAT monthly electricity price index was confirmed by the reference price performance of the protected-tariff service for a resident domestic consumer with annual consumption of 2,700 kWh and capacity of 3 kW. In the course of 2009 and the first half of 2010, the protected prices gradually fell to a level over 8% lower than that seen two years earlier (Fig. 2.26).

FIG. 2.26

Enhanced protection conditions for average domestic consumer with annual consumption of 2,700 kWh and capacity of 3 kW

€c/kWh(A)



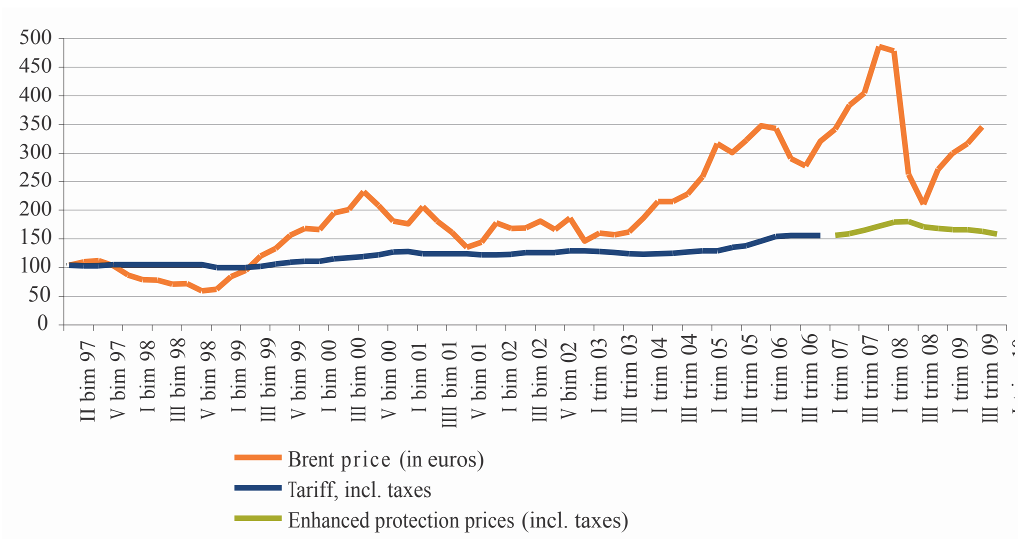
(A) Before 1 July 2007, network costs included sales marketing costs (which could not be identified as no specific tariff component existed for domestic tariff D2). In the second half of 2007, however, a PCV component was introduced to cover such costs. Since then, this component has been included, more correctly, under procurement costs.

The liberalisation process and the restructuring of the electricity sector have cushioned the impact on electricity prices of the high tensions experienced in international fuel markets from spring 2004 onwards. They have also lessened the effects of the marked volatility of the crude price in 2008 and 2009 (Fig. 2.27).

FIG. 2.27

Electricity tariff (later, protected-tariff) and oil price trends

Indices
3rd 2-month period
1997=100(A)



(A) Average domestic consumer with an annual consumption of 2,700 kWh and capacity of 3 kW; €c/kWh.

Source: AEEG, from own data and from Platt's.

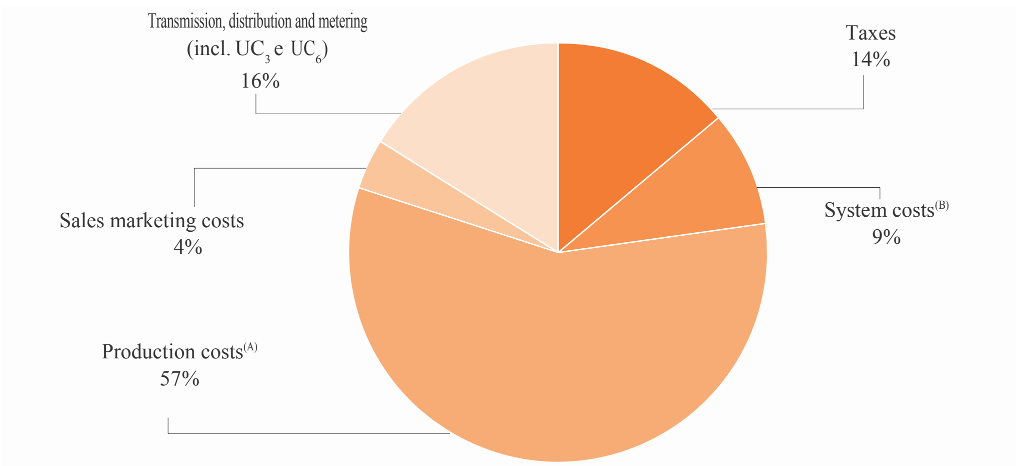


FIG. 2.28

Protected tariff for average domestic customer with annual consumption of 2,700 kWh and capacity of 3 kW

Percentage breakdown, 1 April 2010

(A) Production costs include fuel costs, fixed generation costs, dispatching costs, production-capacity remuneration, interruptibility-service remuneration and UC_1, UC_5 and PPE components.

(B) System costs include all A components, component UC_4 and component MCT

At 1 April 2010 the price of electricity for a resident domestic consumer with annual consumption of 2,700 kWh and capacity of 3 kW was 13.50 c€/kWh net of taxes and 15.76 c€/kWh including taxes.

The components covering transmission, distribution and metering costs (including tariff components UC3 and UC6 as they concern the equalisation of transmission and distribution costs and service continuity improvements) account for 16% of the total gross price. This is slightly up on the second quarter of 2009 (15%).

Again at April 2010, the components covering electricity procurement and marketing costs (Fig. 2.28) represented 61% of the gross price, three points less than a year earlier. These components included the following items:

- UC1, the component covering residual imbalances deriving from the equalisation mechanism for the costs of procuring electricity for customers in the captive market up to 30 June 2007, and electricity for the protected service from 1 July to 31 December 2007. On 1 April 2010, this component was cancelled. The corresponding account in the *Cassa conguaglio per il settore elettrico* will be closed once all the equalisation amounts for 2007 have been calculated and settled.
- PPE, the component covering imbalances in the equalisation system for the purchase and dispatching costs of electricity supplied to users of the protected-tariff service. This component came into force on 1 January 2008 and was activated in January 2009. At 1 April 2010, it was equal to 0.0 c€/kWh.
- charges that, in the tariff component system defined for the captive market, were applied through, respectively, the UC5 component (difference between actual and standard network losses) and components CD (remuneration of production capacity availability) and INT (remuneration of the interruptibility service). With effect from the third quarter of 2007, these have been incorporated in a single element (PD) covering dispatching costs.

At 1 April 2010, the component covering sales marketing costs amounted to 0.67 c€/kWh and accounted for about 4% of the total price.

In the second quarter of 2010, general system costs for an average domestic customer using the protected service amounted to 1.40 c€/kWh, which corresponded to 9% of the gross price. General system costs include components UC4 relative to tariff surcharges, MCT for geographical compensation measures, and the new “As” component covering the “social bonus”. Chapter 2 of Volume 2 [available in Italian] contains a detailed description of general system costs.

Service quality

Transmission service quality

The improvement seen in 2008 in the continuity of the electricity supply with respect to previous years was confirmed in 2009. In the transmission sector, service continuity is commonly measured using the Energy Not Supplied (ENS) indicator.

The performance of this indicator over the last four years is shown in table 2.43, where the information for 2008 refers to data received from Terna in April 2010. These figures are still being checked by the Authority.

TAB. 2.43

Energy Not Supplied for outages affecting all users(A)

YEAR	MW
2006	3,477
2007	8,465
2008	2,440
2009	2,464

(A) Data are calculated for the entire national territory. They refer to outages affecting all users connected to the relevant transmission system as a result of malfunctions for all causes, including outstanding events and without distinction as to origin.

Source: Notifications from Terna to the AEEG.

In the course of 2009 the previous year's reduction in the number of outstanding events (that is, power outages having a major impact in terms of ENS) was confirmed. Just one outstanding event occurred, in the Naples area in July. This took the form of a temporary interruption in operations on the 220 kV grid as a result of work being carried out to set up a new 220 kV cable connection. (Tab. 2.44).

TAB. 2.44

Energy Not Supplied as result of outstanding events(A)

YEAR	NUMBER	MWh
2006	2	2,548
2007	11	7,468
2008	1	560
2009	1	370

(A) With effect from 1 January 2008, Resolution 281/07 of 7 November 2007 redefined an outstanding event as an outage involving an ENS figure of over 250 MWh. Up to 31 December 2007, Resolution 250/04 of 30 December 2004 had envisaged an outstanding event as involving an ENS figure of over 150 MWh and lasting over 30 minutes.

Source: Terna Annual Reports and notifications from Terna to the AEEG.