2010 National Report to the European Commission

(Covering the period 01.01.2009 – 31.12.2009)

Regulatory Authority for Energy (RAE)

Athens, November 2010

REGULATORY AUTHORITY FOR ENERGY

132, Piraeus str., 118 54 Athens, Greece

Tel.: +302103727400, Fax: +302103255460

E-mail : info@rae.gr, Website: www.rae.gr

Table of contents

1. Foreword

2009 has not been a year of significant changes; however, some important steps towards much-needed structural reform for the effective opening of the electricity and gas markets have been taken.

In electricity, abundance of water for hydroproduction, mild weather both in the winter and in the summer of 2009, as well as substantial reduction in demand due to the ongoing economic crisis, resulted in unusually low prices in the wholesale market, driven by the incumbent's lignite-fired plant bids. This allowed for a profit margin and an opportunity for entry to the retail market in the most profitable consumer categories, such as large commercial. For the first time, by the end of 2009, nearly 5% of medium-voltage customers had switched supplier.

From a regulatory point of view, there are four (4) main areas, in which the results at the end of 2009 were not satisfactory and on which the Regulator has to work intensely in 2010:

- Wholesale market: Although full implementation of the provisions of the *Grid and Market Operation Code* for the wholesale market was scheduled for 2009, this was further postponed to 2010 (eventually, it took effect on September 23, 2010). The Regulator has initiated a close monitoring procedure to ensure smooth functioning of the wholesale market and to avoid abuses of dominant power.

- Retail tariffs: In the retail market, the low and medium voltage tariffs still remain regulated by the State. However, we have made significant progress in formulating the methodology for assessing the correct structure and fair level of retail prices. The monopolistic tariff components have already been carefully estimated and the first bills that separately display charges for energy, distribution, transmission and PSO costs reached final customers in September of 2009. The important next step, on which we will focus during 2010, is to revisit the competitive components of the tariffs, so as to remove distortions due to cross-subsidies, and link them to the production cost, eventually removing regulation.

- Distribution System Operator (DSO): The non-existence of a legally unbundled DSO and the continued undertaking of the DSO duties by an organisational unit integrated within the incumbent, PPC S.A., prevent effective separation of the distribution network activity, in terms of decision making rights and functioning, from the competitive business of the integrated utility. On this issue, Greece received an infringement letter from the European Commission in June 2010.

- Cross-border trading: Cross-border trading arrangements over the interconnections with our neighbouring countries are severely limited and not always transparent, nor in accordance to the provisions of relevant EU Regulations. A second infringement letter received by the Greek government in 2009 pertained to this issue. A strong joint effort should be made in maximising the available interconnection capacity and improving market conditions, especially with the Bulgarian Regulator.

Regarding renewables, at the end of 2009, wind parks and small hydro units were supplying about 3.5% of the electricity consumed in Greece, while installed capacity has reached 8.5% of the total in the interconnected system (12.9% on the non-interconnected islands). Interest in further investment is growing, including photovoltaics, as the incentives provided by the State are generous. Given the unusually low SMP prices and the relatively high feed-in tariffs given to renewables, the TSO faced significant problems in 2009 in paying the RES producers. Our efforts should now concentrate on the effective realisation of the plethora of investment plans, currently in the licensing pipeline.

In the natural gas sector, both the TSO and the incumbent supplier responded efficiently to the Russian – Ukrainian dispute and the gas crisis in the beginning of 2009. For the first time, physical reverse flow was put in effect and Greece supplied Bulgaria with regasified natural gas.

At the end of 2009, the TSO raised issues of contractual congestion and lack of sufficient regulatory tools, in order to refuse access to the first eligible customer that attempted to import LNG for its own consumption. RAE made a strong, but ultimately unsuccessful, recommendation to the TSO to allow access and later initiated a formal investigation procedure on the matter. Although the Regulator's position is that the legal base for third party access was already in place, the incident underlined the urgency for completion of the secondary gas legislation, an issue that became RAE's top priority for 2010 in the natural gas sector.

The Greek Regulatory Authority for Energy

November 2010

2. Main developments in the gas and electricity markets

2.1. Electricity

Year 2009 was completely at contrast compared to 2008, in terms of both water availability and average fuel generation cost. Sharp increase in hydrogenation, coupled with mild winter conditions and below-average summer temperatures, resulted in low prices in the wholesale market, driven by lignite production bids. Exporting opportunities did arise during 2009, as well as opportunities for new entries in the retail market.

Low capacity requirements during 2009 have not given any incentive to units under construction to accelerate their commissioning, and as a result no new generation capacity has been introduced this year. The only IPP in commercial operation, T-Power CCGT in Thessaloniki, was out for most of the year, due to serious technical problems.

No significant developments took place in 2009 as regards rules for cross-border exchanges of electricity, compared to 2008. The construction of a 400 kV (nominal capacity 2000 MVA) interconnection between Greece and Turkey was completed in 2008. Synchronous operation of the two systems is expected by September 2010, while cross-border trade is foreseen to start by the end of 2010.

Compliance to Regulation 1228/2003 and Congestion Management Guidelines remains an issue that the Regulator is following closely. A strong joint effort, together with the Regulators of neighbouring countries, especially those at our northern borders, should be made in maximising the available interconnection capacity, ensuring transparency and improving market conditions.

In the retail market, due to the fact that all separate regulated charges for the use of the transmission system, distribution network and public service obligations were formulated and issued on time, and the fact that very low prices in the wholesale market have prevailed, independent suppliers found an opportunity to enter the retail market, taking advantage of PPC's distorted (not cost-reflective) and still bundled tariffs. Finally, in September 2009, PPC introduced a new standard bill for all customers, where all explicit charges were separately indicated, although the tariffs offered were still bundled. In November 2009, PPC sent to the Regulator its proposal for the unbundling of its tariffs with significant delay, following the Ministerial Decision of 2007 that was asking for the unbundling of the tariffs to take place within 2008.

2.2. Natural Gas

In 2009, the Regulator intensified its efforts to complete the regulatory framework both for transit and domestic gas flows. In summary, major developments from the regulatory perspective were:

- The completion of the Authorisation Regulation, that sets the entry rules for both gas suppliers and developers of independent infrastructure in the country, following the public consultation procedure that was concluded at the end of 2008.
- The completion of the Network Code, following a public consultation procedure that was concluded in February 2009.
- The completion of the draft Supply Code for Eligible Customers, following a public

consultation procedure that was concluded in March 2009.

At the same time, the gas sector faced several new challenges during the said year.

The Russian – Ukrainian dispute and the gas crisis in the beginning of 2009 affected Greece, endangering the continuity of natural gas supply. Both DESFA SA (the Greek TSO) and DEPA SA (the incumbent Supplier) responded efficiently and, as a result, no major supply interruptions were observed in the market. At the given supply levels, the LNG facility at Revythoussa Island, Attica Bay, proved to be an invaluable alternative source of gas for the Greek System. Moreover, physical reverse flow in the Greek System was successfully put into effect for the first time during the crisis, in order for DEPA SA to supply Bulgaria with regasified LNG.

The gas supply crisis and its repercussions regarding prioritisation of small/smart interconnections, along with slow developments regarding new sources and transit regimes upstream of the country, led to rather slow developments in the area of transit projects of relevance to Greece.

In the domestic front, demand fell below 2008 levels and far below the forecast quantities for 2009, mainly due to a decline in demand by gas-fired power plants and relatively mild weather conditions in the second half of the year. The supply situation remained unchanged, both in terms of market shares and gas supply sources, with the incumbent DEPA SA being the sole supplier in the country.

An important case of refusal of third-party access took place at the end of 2009, when an eligible customer attempted to import LNG for its own consumption. The TSO raised issues of contractual congestion and lack of sufficient regulatory tools to deal with the situation. The Regulator’s position on the issue was that full TPA had to be provided to the interested party, and, accordingly, a strong recommendation was issued to the TSO. Nevertheless, access was never realised and, following a complaint submitted by the affected eligible customer, RAE launched a formal investigation that was completed in May 2010.

In 2009, eligibility rights were extended to all domestic consumers, except those located within the concession areas of the three (3) distribution companies (EPAs) operating under a monopoly regime, in accordance with article 28.8 of Directive 2003/55/EC.

Finally, further progress was made during 2009 regarding the accounting unbundling rules submitted by all gas undertakings in Greece.

3. Regulation and Performance of the Electricity Market

3.1. Regulatory Issues

3.1.1. Management and Allocation of interconnection capacity and mechanisms to deal with congestion

Internal Transmission System Congestion and Management

There has been no change in mechanisms to deal with congestion in the internal transmission system. Congestion management is inherent to the market mechanism (market splitting for Generators), as described in detail in last year's Report.

Cross-border congestion

During 2009, cross-border trade of electricity occurred with northern neighbouring countries (Bulgaria, FYROM and Albania) and with Italy (submarine, 400 kV DC link, 500 MW rated capacity). Congestion on northern interconnections predominantly appeared in the import direction, while the Greece-Italy link exhibited congestion in both directions.

The main principles of interconnection congestion management rules in 2009 were the following:

- Annual, Monthly and Day-ahead (D-1) Explicit Auctions of Physical Transmission Rights
- UIOSI rule applied to long-term PTRs (reallocation by HTSO at Monthly and Day-Ahead Auctions) and UIOLI at the time of firm nomination
- Long-term PTRs are freely transferable between participants, subject to TSO approval of transferee eligibility.
- Allocated long-term PTRs subject to cancellation by HTSO until deadline for declaration of intention to use (D-1, prior to day-ahead auction) and up to a total of 35 days per year, in which case PTR holder is compensated at 100% of long term auction price.
- Daily PTRs are firm.

Under this scheme, during 2009 HTSO managed capacity allocation on the interconnections and directions as presented below.

Counterpart Country	Imports to Greece % of NTC	Exports from Greece % of NTC
Bulgaria	50	100
FYROM	50	100
Albania	50	100
Italy	0	100

Table 1. HTSO responsibility for capacity allocation on interconnections

Congestion on the Greece - Italy interconnection for the direction from Italy to Greece was managed by the Italian TSO for the entire NTC, through annual, monthly and daily auctions, according to the same auction rules. On interconnections where congestion is managed entirely by one TSO (100% NTC), congestion revenue is split between adjacent TSOs on an equal basis.

Interconnection capacity allocation results in 2009

In the **import** direction, HTSO organised one annual and 12 monthly auctions on the northern interconnections. Due to uncertainty in availability of energy for imports primarily from Bulgaria since the beginning of 2007, the annually available import capacity from the northern borders was severely limited. NTC was subsequently estimated on a monthly basis taking into account a forecasted energy balance, and ATC for imports was allocated mainly through monthly auctions. A significant increase in the number of day-ahead auctions organised for imports in 2009, compared to 2008 (716 auctions in total for all northern interconnections).

In the **export** direction, HTSO organised one annual, 10 monthly and 313 daily auctions.

RAE accepted HTSO proposals to somewhat limit long-term allocation of interconnection capacity for exports, so as not to endanger security of supply in the Greek system, considering the fact that similar action is taken also by neighbouring EU-member states. RAE acknowledges that these practices have to be checked against the relevant provisions of the Regulation 1228/03. However, in the issue concerning cross-border trade, all parties involved should demonstrate their strong commitment in complying with Reg.1228/03 and improving market conditions, by maximising the available interconnection capacity.

Annual and monthly auction results are presented below. Detailed auction results, including those from daily export auctions, and an assessment thereof are presented in the framework of the CSE/ERI Interconnection Report.

Period	Border	Auctioned capacity (MW)	Product Definition	Auction Price (€/MWh)	Number of bidders	Number of successful bidders
JAN - DEC	BG	50	Base load	15.24	14	4
APR - SEP	BG	50	Base load	17.23	11	3

Table 2. ***Annual*** *auction results for* ***imports*** *to Greece*

Period	Border	Auctioned Capacity (MW)	Product Definition	Allocated Capacity (MW)	Auction Price (€/MWh)	Number of bidders	Number of successful bidders
APR, MAY, SEP, DEC	All borders	100	Peak (06:00-22:00 CET)	IT: 100	2.67	15	9
MAY	All borders	100		IT: 100	1.75	12	8
JAN-MAY, SEP-DEC	All borders	250	Off Peak (22:00-06:00 CET)	IT:235 AL:15	0.51	12	8

Table 3. ***Annual*** *auction results in* ***export*** *direction*

		Allocated Capacity & Auction Price											
		JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	AUG	SEP	**OCT**	**NOV**	**DEC**
BG	MW	175	225	250	280	280	280	50	-	280	50	180	125
	€/MWh	12.59	8.2	0.72	0.50	0.55	7.77	6.22	-	0.33	3.50	1.25	3.50
FYROM	MW	45	45	75	25	30	75	125	125	50	25	50	25
	€/MWh	8.2	5.0	0.77	2.97	3.87	7.89	5.04	0.75	0.63	0.21	0.24	3.76
AL	MW	-	200	100	100	100	100	100	75	-	-	-	125
	€/MWh	-	0.15	3.0	1.04	4.71	1.53	1.61	0.34	-	-	-	0.27

*Table 4. **Monthly** auction results in **import** direction (base product)*

		Allocated Capacity & Auction Price											
		JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**
BG	MW									50	175		
	€/MWh									0.07	0.25		
	MW										50		
	€/MWh										0.13		
FYROM	MW				25	70				25	20		
	€/MWh				0.77	1.01				0.22	0.17		

*Table 5. **Monthly** auction results in **import** direction (intermittent product)*

		Allocated Capacity & Auction Price											
		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
IT	MW			100(a)	100(a)	100(a)	250(o)	250(o)	100(p) 250(o)	250(p) 250(o)	150(p) 100(p) 265(o)	300(p) 265(p)	300(p) 265(o)
	€/MWh			11.23	12.0	11.57	0	1.78	7.25(p) 2.23(o)	15.16(p) 14.31(p) 3.51(o) 2.93(o)	3.01(p) 2.98(p) 0.82(o)	5.17(p) 1.14(o)	5.02(p) 2.05(o)
BG	MW												
	€/MWh												
FYROM	MW						90(o)						
	€/MWh						0						
AL	MW						160(o)				200(o)	220(o)	235(o)
	€/MWh						0				0	0	0

*Table 6. **Monthly** auction results in **export** direction*
*(*a: All hours, p: peak hours 06:00-22:00 CET, o:off-peak hours 22:00-06:00*)*

Provision of information by the TSO in the context of congestion management

There has been no significant change in the provision of information to market participants in the context of congestion management, compared to 2008.

Integration of congestion management in wholesale market functioning

There has been no change compared to practices applied in previous years (reference is made to 2007 National Report). The current scheme (explicit auctions of PTRs), however, does not establish effective integration of interconnection congestion management with the functioning of the wholesale market.

Congestion income

Income from congestion management has been used for purposes complying with the provisions of Reg.1228 and CM Guidelines, namely towards compensation of cost of new interconnections, as well as to reduce transmission network tariffs (see also par. 3.1.2 below).

According to HTSO's Reporting to ENTSO-e, total net income from CM during 2009 (before any taxation) was 34.49 MEuro.

3.1.2. **The regulation of the tasks of transmission and distribution companies**

Network Tariffs

Transmission Network Tariffs

Transmission Network tariffs are calculated on the basis of the annual transmission system cost, which is defined in the Grid and Market Operation Code[1], and is the sum of the annual rent owed by the HTSO to PPC SA and the annual cost of any work for the expansion of the System. The annual system cost is also adjusted to take into account the differences between the forecasted and actual revenue from system users during the previous year. For 2009, estimated rent owed to the asset owner (PPC) is €294,4m (including 8% nominal, pre-tax Allowed Rate of Return), whereas total transmission costs to be recovered through the tariffs are €262.7m, accounting for the over-recovery of costs through the charges applied in previous years[2].

Following a Grid and Market Operation Code amendment in April 2009, transmission system costs are allocated 100% to load (previously, approx. 15 % was allocated to generation). The methodology for the calculation of the Transmission Use of System (TUoS) tariffs for HV connected customers is set out in the Grid and Market Operation Code and for the customers connected to the Distribution Network (MV and LV) in a related Manual approved by RAE[3].

Tariffs for HV connected customers follow a €/MW structure, charged on the customer's average hourly demand during the following three hours: system summer peak, system winter peak and the maximum of the two. Demand is adjusted for losses accordingly (depending on the connection voltage). Given the limited metering capabilities of consumers connected to the MV and LV networks (lack of measurements of coincident peaks), for the purpose of calculating TUoS charges, the transmission cost is further allocated to the two voltage levels based on their total energy. The methodology set out in the relevant manual further specifies the following:

- For the purposes of TUoS charging, the following customer categories apply: Domestic, Agricultural (MV and LV), Public Lighting, Other MV, Other LV.
- Some customer categories have reduced or zero TUoS charges (e.g. agricultural customer contracts include clauses for load reduction at peak hours, overnight demand in zonal tariffs is charged at 0).
- MV customers have a capacity charge only (no energy charge for TUoS) which is charged on the basis of maximum metered demand (MW) during peak hours (11am-2pm).
- For LV customers, only 20% of the allocated cost is recovered through capacity charges which are charged on the basis of the connection capacity (kVA) given the lack of metered demand (MW).

---

[1] Ministerial Decision Δ5-ΗΛ/Β/8311/9-05-2005 and subsequent amendments.
[2] Ministerial Decision of 23 June 2009, following RAE opinion 177/2009.
[3] RAE Decision 1332/2009.

Customer	Capacity Charge	Energy Charge (€/kWh)
HV	25,166 €/MW chargeable demand (3 coincident peaks)	-
MV (non agricultural)	2,025 €/MW max demand during peak hours	-
Domestic	0.33 €/kVA of Agreed Capacity per year	0.524*
Other LV (non agricultural)	0.70 €/kVA of Agreed Capacity per year	0.576*
Public lighting	0.70 €/kVA of Agreed Capacity per year	0.192

Table 7. Transmission charges for 2009
**Applies to daytime consumption only for customers with zonal metering*

A significant part of congestion revenues, in the order of 54.5 MEuro was allocated during 2009 to cover the cost of the Greece – Turkey 400kV interconnection.

Furthermore, an additional amount of congestion revenues, namely 23.8 MEuro was allocated to reduce transmission tariffs for 2010.

Distribution Network Tariffs

Regarding the allowed distribution revenue, there is currently no formal methodology set for its calculation given that the Distribution Code (which will include the methodology for estimating the annual distribution costs) has not been adopted yet. As a transitional measure, the methodology applied is the one currently used for the transmission system[4]. The elements for distribution costs in 2009 were as follows[5]:

- Allowed operating expenses: €500,6m. This is a reduced amount compared to the amount requested by PPC (€518,7m) and incorporated a 2% efficiency (i.e. reduction) factor for 2008 and 2009, applied on the 2007 expenses, according to the PPC unbundled accounts.
- Asset depreciation: €118 million.
- Capital employed: €2.238m.
- Allowed Rate of Return (nominal, pre-tax): 8%.

As a result, the total allowed revenue for the distribution activity in 2009 was €801.2 million. Of these, about €78m are estimated to be recovered by MV connected consumers and the remaining by LV connected consumers.

For the purpose of calculating Distribution Use of System (DUoS) charges, consumers are categorised based on their connection voltage and metering capabilities. More specifically, consumers were categorised into five categories: MV consumers, domestic consumers, LV consumers with maximum demand meters (with and without reactive power metering) and other, non-domestic LV consumers.

4 Ministerial Decision of 31 Dec. 2007, following RAE opinion 294/2007
5 Ministerial Decision of 23 June 2009 following RAE opinion 180/2009

For MV customers, 50% of the cost is recovered through a capacity charge and 50% through an energy charge. The percentages for LV customers are 20% and 80% respectively.

The final resulting Distribution Use of System unit charges for 2009 per consumer category are presented in the following table. The unit capacity charge is applied to the customer *Agreed Connection Capacity*. The unit energy charge is applied to the metered energy adjusted for the average power factor (assumed to be 1 for the consumers without reactive power metering).

Customer Category	Capacity Charge (€/kVA of Agreed Capacity per year)	Energy Charge (€/kWh)
MV Customers	5.18	0.32
LV Customers with maximum demand and reactive power metering	4.15	1.66
LV Customers with maximum demand metering but without reactive power metering	3.40	1.89
LV Domestic Customers	1.20	1.89
Other LV Customers (without maximum demand metering)	1.75	1.89

Table 8. Distribution Use of System Charges for 2009

Network Performance and Quality of Service

In 2009, a procedure for the monitoring of the performance of the transmission system and the HTSO was designed by RAE in accordance with the Grid and Market Operation Code provisions. This procedure is being applied during 2010, after a preliminary coordination with the HTSO. The procedure considers system availability, customer minutes lost, fault statistics etc.

Performance and quality of service standards and obligations and the respective monitoring processes have not been set for the Distribution System Operator yet; therefore, currently the DSO does not report any quality of service indicators. Relevant arrangements are to be developed under the umbrella of the Distribution Network Code.

The proposal of RAE for the *Distribution Network Code*, which is yet to be adopted, envisages a penalty/reward scheme for quality of service regulation. In this context, the role of the Regulator encompasses the following:

i. Definition per regulatory review period of the regulated service quality dimensions, the corresponding overall and individual minimum quality standards, as well as the respective penalties/rewards (all the above are established by a Ministerial Decree, following a consenting opinion by the Regulator, in conjunction with the allowed revenue of the distribution business).

ii. Approval of rules, procedures and methodologies for monitoring, assessing and reporting service quality levels.

iii. Validation of data completeness and accuracy.

Quality of Service indicators – Distribution Network

DSO obligations on Quality of Service (QoS) monitoring and the relevant details will be established in the Distribution Network Code, as mentioned previously. Continuity of supply and commercial quality indicators are currently calculated by PPC following internally defined rules not reviewed by the Regulator and are, therefore, not reported (by the Regulator). Review of PPC internal rules and data on QoS dimensions monitored to date, was initiated by the Regulator in 2008, and continued throughout 2009. This allowed the Regulator to report on the overall service quality level, based on available, non-verified, historical data up to 2008, to formulate and publish its opinion on these, but mainly on current PPC practices regarding service quality monitoring and reporting, as well as necessary improvements thereof. The work is considered preparatory in the context of the service quality regulation scheme, to be applied once the *Distribution Network Code* is enforced.

Provision of information on Connection and Use of System tariffs, charges and conditions

Legal obligations are in place for publication of data by the TSO. The TSO publishes information on TUoS tarrifs. Connection conditions and charges have not yet been approved by the Minister for Development.

No legal obligations are in place for publication of data by the DSO, since neither the Distribution Network Code nor the terms for the Licence of the DSO were available during 2009. DUoS tariffs are published by the Regulator.

3.1.3. **Effective unbundling**

Transmission

The unbundling regime of HTSO remained unchanged during 2009. Please refer to last year´s National Report for details.

Distribution

The absence of a legally unbundled DSO and the continued undertaking of DSO duties by an organisational unit integrated within PPC S.A. continue to prevent effective separation of the distribution network activity, in terms of decision making rights and functioning, from the competitive business of the integrated utility.

The organisation of the distribution business in two separate entities (Network Operator and Network Assets Owner) with complementary and/or interrelated duties and responsibilities, as foreseen by Law 3426/2005, is considered inefficient, as explained in last year's Report. However, no progress has been achieved in 2009 towards implementing a more efficient scheme (organisation of the entire distribution business, operation and ownership of assets, under a single entity).

3.2. Competition Issues

3.2.1. **Description of the wholesale market**

Market Design: Final and Transitional Form

A pure mandatory pool model has been adopted for the Greek wholesale electricity market, initially introduced in 2005 and expected to be implemented gradually, through certain transitional phases. At its final form, the market design involves:

- A Day-Ahead compulsory market, where a cost-minimising plant dispatch is derived simultaneously for the provision of energy and ancillary services, based on predicted demand, generators' offers, suppliers' bids, plant availabilities, must-run generation (e.g. mandatory hydro, renewables' and cogeneration output), interconnection schedules, and various technical constraints both at the plant and the network level.

- The Real-Time dispatch operation, adjusting the day-ahead schedule based on updated availability and demand information and additional security constraints.

- The Imbalances Settlement for deviations from the Day-Ahead schedule.

- A Capacity Adequacy Mechanism for the partial recovery of capital costs.

For a detailed description, please refer to Appendix I of last year's National Report.

In the day-ahead market, uniform pricing applies, reflecting the offer of the most expensive unit dispatched so that predicted demand is satisfied. Zonal pricing, intended to reveal congestion problems and signal the location of new capacity, has not been activated yet, although two zonal prices, applicable to generators, are explicitly derived, currently only as an indication. Participants may enter into bilateral financial contracts (CfDs), but physical delivery transactions are constrained within the pool and related contracts do not exist. A cap of 150 €/MWh has been imposed on generators' offers.

At the transitional stage of the market that was in effect during 2009, the following rules or mechanisms were introduced:

- A cost-recovery, compensation mechanism is applied for units dispatched by the TSO outside the cost-minimising schedule.

- The Imbalances Settlement has not been activated yet as a distinct process, but instead, an overall market settlement is conducted through ex-post prices. These are derived by re-solving the same cost-minimisation algorithm as in the day-ahead schedule but substituting day-ahead forecasts by metered values of the various inputs.

The ex-post prices are applied to actual quantities consumed or produced (the latter reflecting the real-time dispatch orders of the TSO) and are revealed with a time lag of up to twenty days, due to data verification (mainly of wind output). This delay, although inevitable to some extent, augments the financial uncertainty, particularly for small market players.

Regulatory Progress over 2009

The full implementation of the 2005 Grid and Market Operation Code, known as the “Fifth Reference Day” (i.e., the fifth and final step of the transition period) was not enforced within 2009 and has been rescheduled again and again, finally taking effect on September 23rd 2010. Since January 1st 2009, the Day-Ahead plant dispatch has been derived simultaneously (co-optimised) with a schedule for the procurement of ancillary services (primary and secondary reserve). Thus, over 2009 and until the Fifth Reference Day takes effect, the Day Ahead market provides an indicative unit commitment schedule and a reference spot price (SMP forecast), while cash-flows are based on the ex-post SMP.

The repeated rescheduling of the 5th Reference Day is attributed to the following factors:

- Software adjustments by the TSO
- Resolution of various technical issues (e.g. parameters for imbalance charges, credit cover mechanism for suppliers, metering specificities and data processing times, technical constraints in the dispatch of large co-generation units)
- Market distortions, related to the real (vs. declared) availability of generation plants, which caused artificially suppress day-ahead prices and could, subsequently, diminish the largest fraction of generators’ payments, if the final market design is applied.

These market distortions, manifested as systematic behaviour in various analyses within 2009, are summarised below:

- Real-time under-performance of obsolete lignite plants (relatively to declared maximum capacity)
- Under-declarations by load representatives
- Large discrepancies between week-ahead and day-ahead schedules for mandatory hydro production
- Unscheduled dispatch of certain units (Ag.Georgios, Komotini) for reasons of network stability.
- Limits in energy exports from Greece due to the adopted approach for ATC derivation.

RAE has been assessing regulatory measures to gradually resolve such distortions, mainly orientated towards the following directions:

- Penalising systematic deviations from day-ahead declarations
- Removing rules that are often abused (ability to offer 30% of a generation plant’s capacity below minimum variable cost)
- Introducing stricter definitions for mandatory hydro, making week-ahead declarations more binding, deriving market prices based on the maximum quantity between declared mandatory and actual, injected hydro
- Incorporating CO_2 opportunity costs into the lower limit of price offers.

Emphasis was also placed on transparency and timely information diffusion by PPC. In this context:

- Given the critical influence of hydro production on wholesale prices, PPC was requested to publish 12-month rolling estimates of mandatory hydro, reservoir inflows and storage levels, as well as historical, annual curves, so that deviations between target and actual levels are made clear and potential corrections can be anticipated. PPC was also requested to publish hydro schedules prior to the closure of interconnection auctions, so that traders’ positions can be adjusted accordingly.

- Apart from regular monitoring, an extensive investigation was conducted over the period 1-16 October 2009, as significant discrepancies were observed among the price bids submitted by natural gas units, with the incumbent's bids not absorbing the significant fuel price increase at the time and appearing significantly lower compared to those of the independent generators. The investigation assessed whether market bids in the pool were above the minimum average variable cost of the units, as required by the market rules, and checked the compatibility between declared fuel costs and invoice data. PPC responded immediately that their bids at the specific period were incorrect, due to an internal error in data communication and provided the true value of their fuel cost. Based on this correction, market prices were re-derived and compared with historical values over the period of the error. The financial impact of this adjustment was evaluated and turned out to be rather limited.

Price Dynamics

As opposed to the high levels that dominated 2008, wholesale prices retained remarkably low levels over 2009, consistently with trends that emerged globally, reflecting the simultaneous reversal of various market fundamentals. Influenced by the declining paths of oil and natural gas prices, the reduction of electricity demand, due to the global recession, and a wet year which boosted hydro production, wholesale prices fluctuated around an average value of 47.40 €/MWh, almost half of the price average in 2008 (87.22 €/MWh). Price movements were less volatile, exhibiting a standard deviation of 16.63 €/MWh relatively to 24.14€/MWh in 2008, reaching a maximum value of 96.52 €/MWh and a minimum of 0 (an isolated case of low demand, where price was set by imports, offered at a zero value). Figures 1-3 display the dynamics of SMP across the year as well as its intra-day profile.

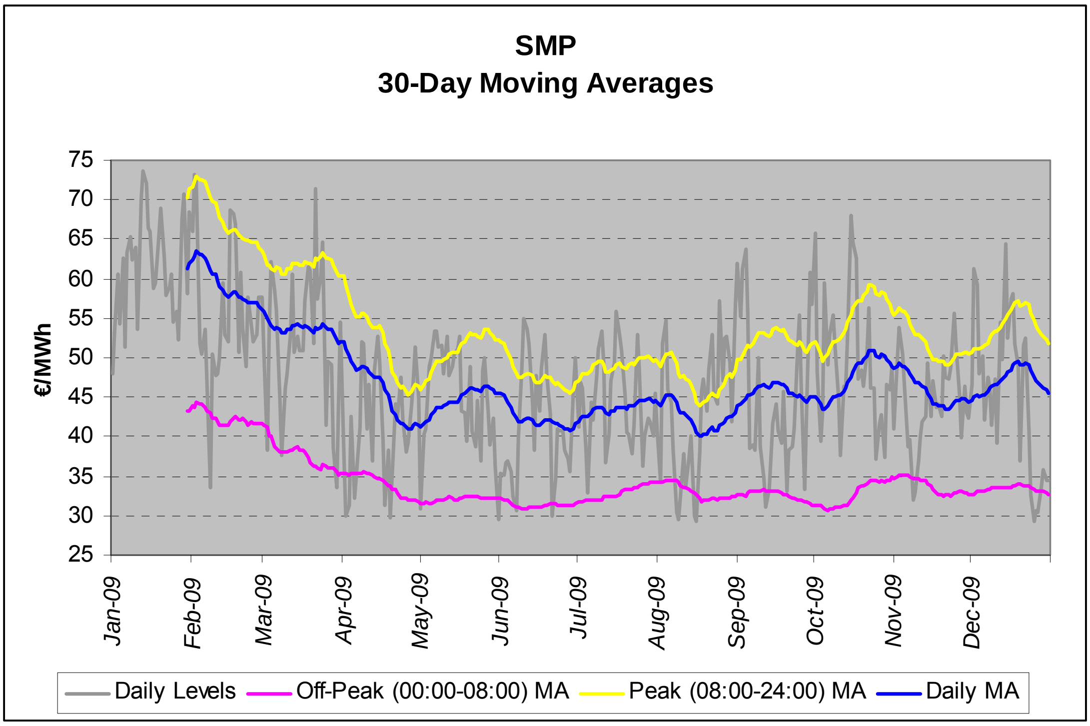

Figure 1. SMP Dynamics (Actual and Smoothed Levels) over 2009

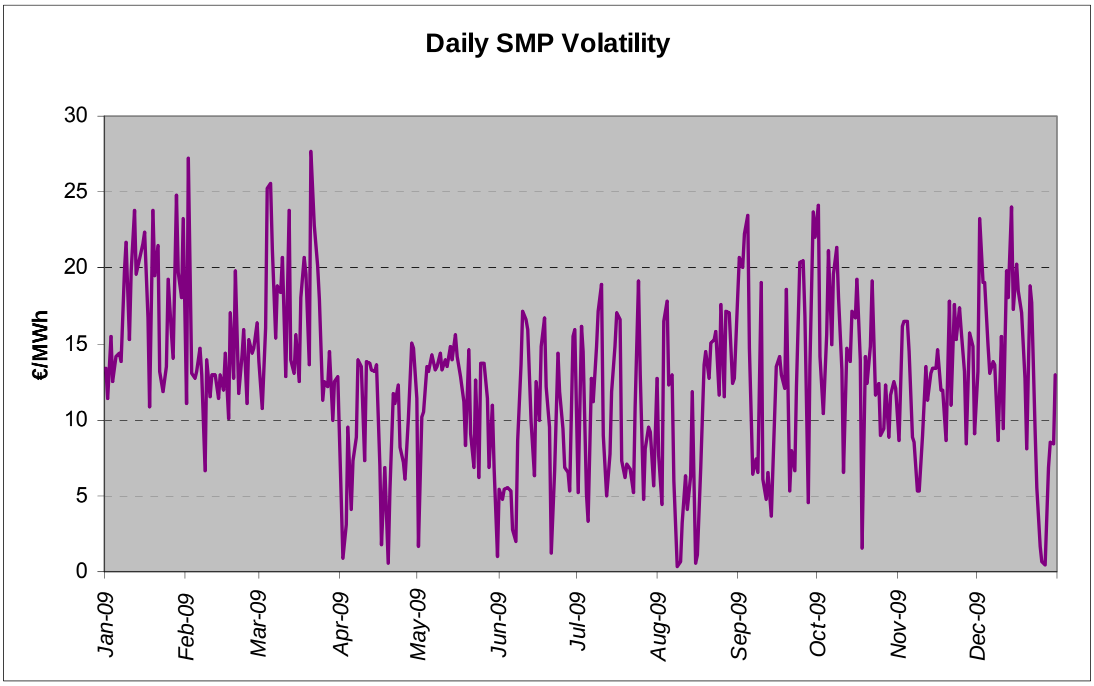

Figure 2. SMP Volatility (st.deviation) over 2009

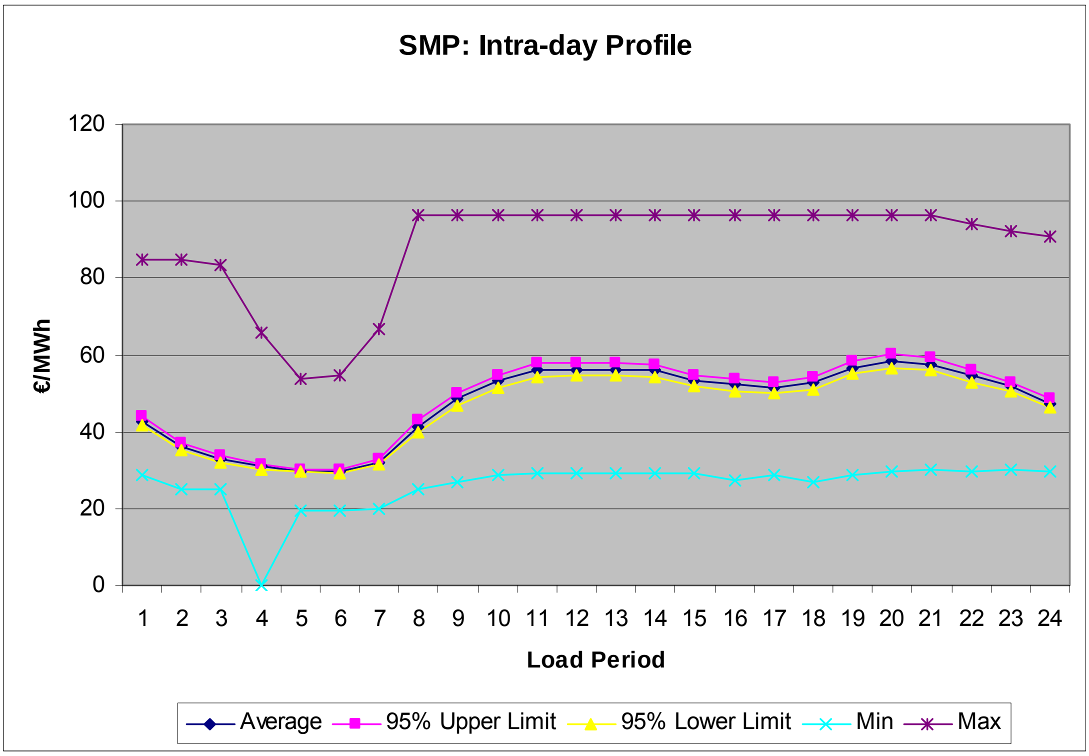

Figure 3. SMP Variation at the hourly level

Incumbent's Influence on Price

Overall, given the highly concentrated market at both sides, wholesale prices remained very sensitive to PPC's bidding behaviour over 2009. Given the substantial retail margins, the dominant trend of the incumbent was to suppress wholesale prices, in order to reduce, effectively, the cost of energy purchases from renewables, independent generators and imports.

In general, price bids of the thermal plants of the incumbent appeared to be very close to the minimum variable cost, with large discontinuities across plant technologies. This translated into high risk exposures for other players, whenever marginal technologies were altered between the (indicative) day-ahead dispatch schedule and the ex-post one, which determined cash-flows. In addition, hydro bids were relatively variable, in response to the evolution of reservoir levels and perhaps, adapted, to some extent, to PPC's interconnection trading. In response to the above observations, RAE has been assessing valuation methodologies for the opportunity cost of hydro, by relating this explicitly to reservoir levels and the marginal fuel. The derived values, updated on a seasonal basis, may form a lower limit on hydro offers, yielding an adaptive and more realistic proxy than the current limit of 53 €/MWh, which reflects past data on marginal plant costs (CCGT).

Overall, the market analyses over 2009 strongly suggested that an appropriate link between wholesale and retail prices is crucial for the market to evolve in a more competitive direction, and hence, major emphasis has been placed on the gradual correction of regulated prices, so that cross-subsidy distortions are reduced.

Fuel Shares

Given the evolution of market fundamentals in 2009, net generation declined by 5.2% relatively to 2008, with natural gas and oil shrinking substantially, by 29.5% and 52% respectively, and net imports declining by 22%. Simultaneously, lignite production exhibited a small increase of 2.5%, while hydro was magnified by 67.11%, as inflows and reservoir levels reached amongst their highest values over the last two decades. Renewable production increased moderately, by 20.4%, still its market share remained low at 3.6%. As a result of the price collapse and sustained price spreads, exports to Italy escalated from 0.18 TWh in 2008 to 2.19 TWh in 2009. Figure 4 presents the allocation of production across the various technologies as well as net imports at the monthly level, while Figure 5 displays the annual market shares across fuel and net imports.

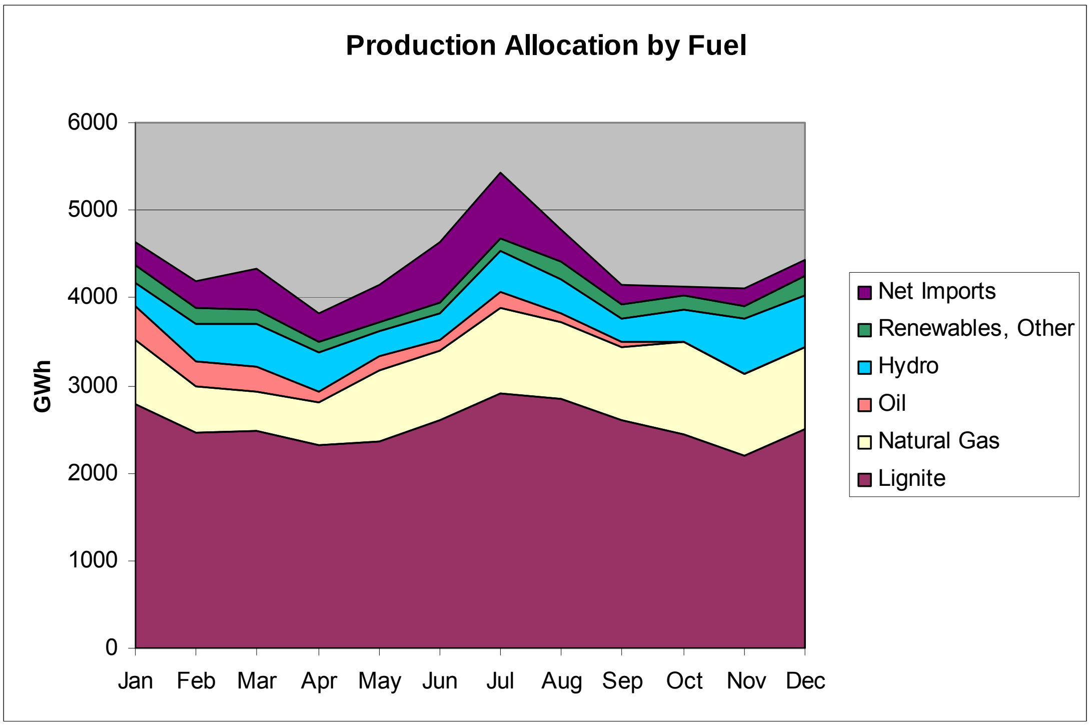

Figure 4. Production allocation across fuels and net imports at monthly level

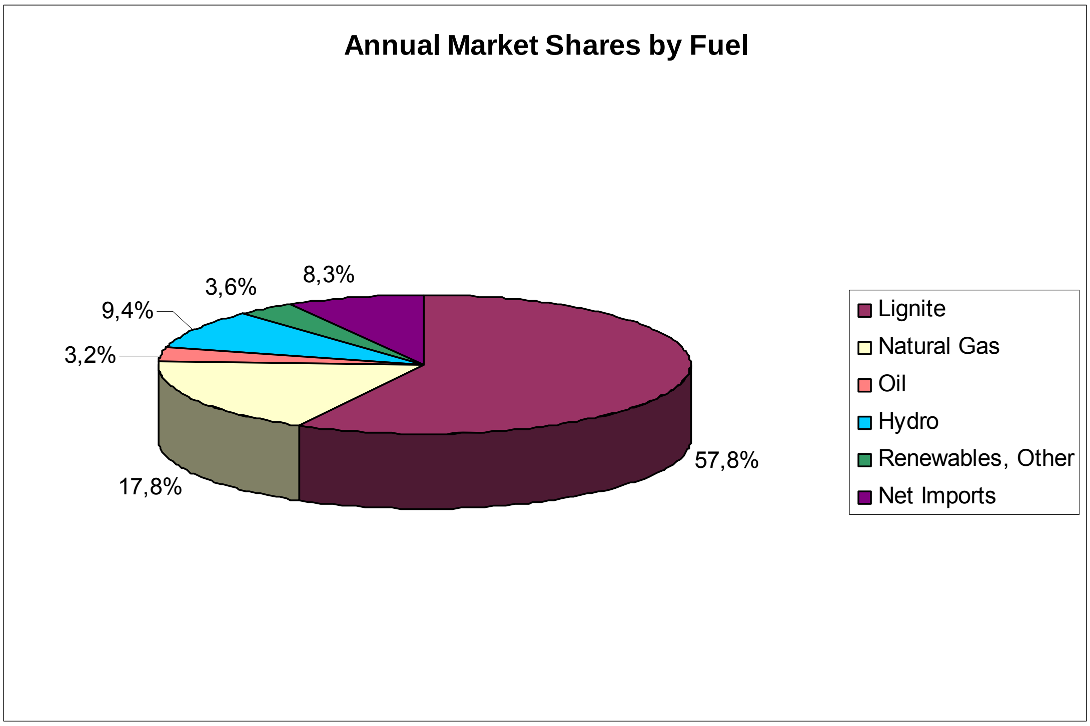

Figure 5. Annual shares of fuels and net imports.

Market Structure

Regarding the market structure, PPC, the national integrated electricity company, has retained its dominant position over 2009. Still, its market share declined slightly, in both the generation and the supply side, with more significant changes expected to occur over 2010. More specifically, Enthess, the only CCGT unit (390 MW) owned by T-Power (currently Elpedison) re-started its regular operation on 10th October 2009, attaining a capacity factor of 64.36% over the remaining period. The plant dispatch had been delayed due to a major outage during last months of 2008, which coincided with a period of limited potential profit. Aluminium of Greece, a large-scale CHP unit (334 MW CCGT), owned by Edessa Hellas (at the time) operated throughout the year at commissioning status (with on-going resolution of technical issues regarding co-generation dispatch), achieving an overall capacity factor of 44.46%, which escalated to 63-82% over the summer months. Heron, a 150MW OCGT unit, previously contracted with the TSO for the provision of ancillary services, retained over a second year a long-term capacity availability contract with the incumbent, PPC. As noted by Heron, this contract, similar to a tolling arrangement, increased substantially its hours of operation, approximately to 1300 in 2009, hence reducing gas transportation charges.

IPP thermal production (sum of Enthess, Alouminion and Heron) represents a market share of 4%. Total IPP production, taking into account the RES and small co-generation not owned by PPC, amounts to 8.2%.

	Ownership	Installed Capacity (MW)	Total Production (MWh)	Capacity Factor
Lignite	**PPC**	4746*	30,879,889	74.28%
Oil	**PPC**	698*	1,704,581	27.88%
OCGT	**PPC**	339	1,190,006	40.07%
	IRON	148	135,663	10.48%
	Total	487	1,325,669	31.09%
CCGT	**PPC**	1578	6,438,762	46.58%
	T-Power	390	509,205	64.36%**
	Total	1968	6,947,967	40.30%
CHP (Large-scale)	**Endessa Hellas**	334	1,300,932	44.46%
Hydro	**PPC**	3018	5,108,625	19.32%
Small Cogeneration	**IPP**	141	144,122	
Renewables	**IPP (mainly)**	917	1,884,418	

Table 9. Installed capacity by fuel and ownership. Capacity factors by fuel type.

Source: Study for the Development of the Transmission System (TSO) and Scada Reports.
** Reported values refer to net capacity.*
*** Initial date of regular plant dispatch: 10/10/2009.*

Due to the over-concentrated market structure in both sides, the HHI index in 2009 remained close to the upper bound of 10,000. On the positive side, there has been significant interest for new plant investments over the recent years, both from PPC and private companies, including trading companies, which are seeking a physical hedge of their positions via capacity investments. Although some investment plans are expected to be reevaluated given the global crisis, the renewables sector remains an attractive field, with the level of feed-in-tariffs being a major stimulus, despite severe bureaucratic (licensing) complications and obstacles. Given the targeted level of wind penetration (7500 MW by 2020) and its intermittent nature, stand-by reserve as well as secondary reserve is expected to emerge as a significant component of financial returns for thermal plants.

Regarding capacity additions in the short-term, two new CCGT units, Thisvi (422 MW), owned by Elpedison, and Heron II (435 MW), owned by Heron Thermoelectricity, are expected to start commissioning trials in May 2010. Another CCGT unit, Agios Nikolaos (412 MW), owned by Endessa Hellas, is under construction, having signed a connection agreement to the system. Until August 2009, six other thermal units, of total capacity 2700 MW, had also applied for connection. Three of those are scheduled to connect to the 400kV system, whereas the others to the 150 kV. The incumbent's new units, Aliberi V (360-400MW) and Megalopoli V (850MW), both CCGT, have been contracted with the TSO. Upon their operation, the obsolete lignite units Megalopoli I and II, of capacity 250 MW, will be decommissioned. For a list of the licensed (new) investments in thermal units at the end of 2009, please refer to Appendix I.

On the supply side, PPC ceased to be the only load representative in the wholesale market over 2009, as a couple of companies started submitting load declarations, exhibiting however, very limited participation at this initial stage. Trading activity in imports and exports got substantially more intense over 2009, with, usually, up to 15 companies active at the interconnection with Italy and significantly less, regularly around 5, at the northern borders. In the past, some demand involvement in the market could be manifested indirectly, e.g. through curtailment arrangements with industrial customers during peaks, which entailed some form of demand response to high prices, even in the context of adequacy measures. Given the economic crisis, which substantially influenced industrial electricity consumption (20% reduction), the potential of such indirect demand-response effects appeared more restricted over 2009. Still, within a recession period, and under the assumption of a link between wholesale and retail prices, demand elasticity to price can emerge as a significant driver for market changes in the near future.

Integration with neighbouring member-states

The relevant electricity market for Greece is, to a significant extent, the national market. The total interconnection capacity of the country in 2009 was 1500 MW, which is going to be augmented in a new direction, i.e. eastwards, as an interconnection with Turkey[6] is expected to be fully synchronised by September 2010. Currently, interconnection with adjacent member states (namely Italy and Bulgaria) amounts to 1300 MW, which corresponds approximately to 13% of annual peak demand (approximately 10000 MW), while interconnections to Albania and FYROM are restricted to 200 MW. Romania, another member state with an emerging, relatively liquid, power exchange is also relevant for price comparisons, as it is indirectly connected, although not adjacent, to Greece. Nevertheless, transit flows through Bulgaria remain ambiguous, due to lack of transparency.

Overall, net imports in 2009 declined by 22% compared to 2008, but this number is certainly not indicating a downward trend in cross-border trading. Instead, it reflects the escalation of exports from 1.96 TWh to 3.23 TWh, while imports remained fairly stable (around 7.6 TWh). Cross-border trading over 2009 exhibited a clearer directional pattern than in previous years, with pure imports from Bulgaria and FYROM being dominant, exports to Albania being the major direction of flow in the line, and the trading direction with Italy responding well to the sign of the price spread.

[6] A 400 kV interconnection between Greece and Turkey (nominal capacity 2000 MVA) was completed in 2008. Since then, the focus was on the synchronous operation of the two systems and particularly, the fulfilment of UCTE network operation standards by the Turkish system. This process, on-going over 2009, is expected to be completed in September 2010.

Consistently with the price shrinkage in wholesale European markets, Italian prices declined as well, but their levels resisted more, due to strong local fundamentals, including substantial market power and congestion issues. The price differential between Italy and Greece strongly signalled exports to Italy over prolonged periods with some reverse signs over off-peak periods (00:00-08:00), where pure imports were conducted at 28% of the times.

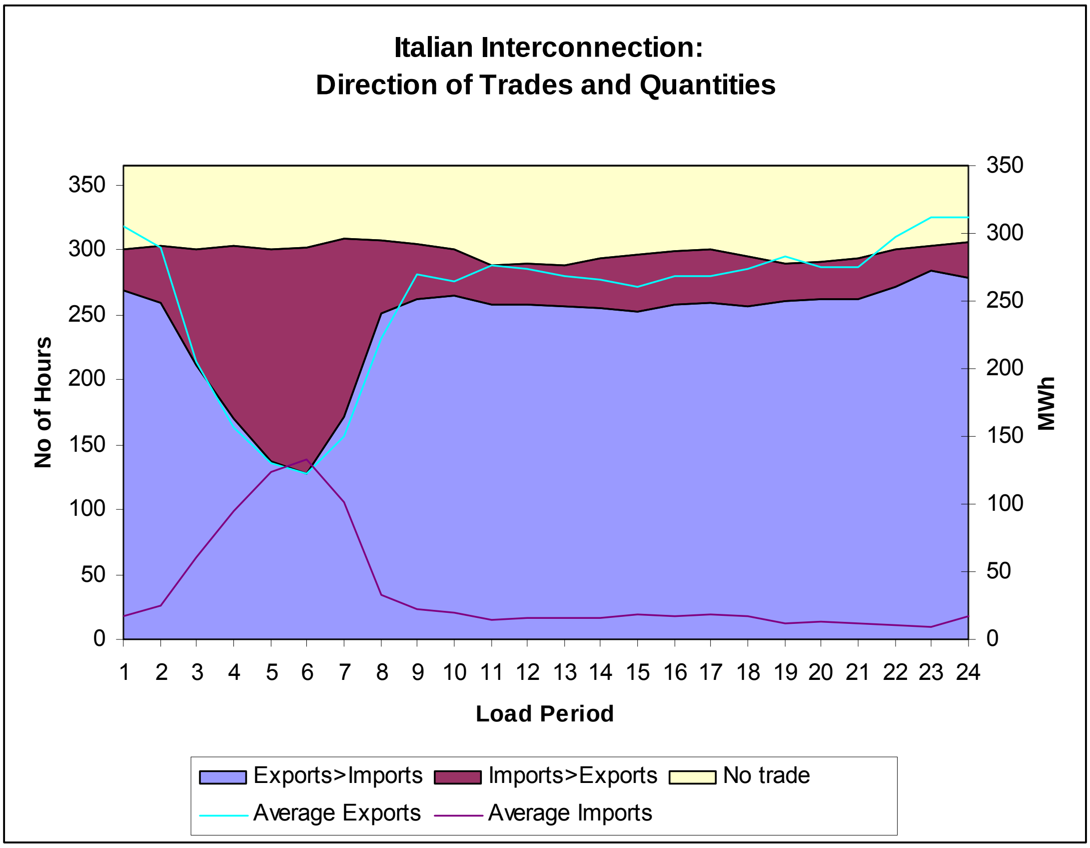

Figure 6. Average hourly imports and exports and number of hours that imports or exports were dominant.

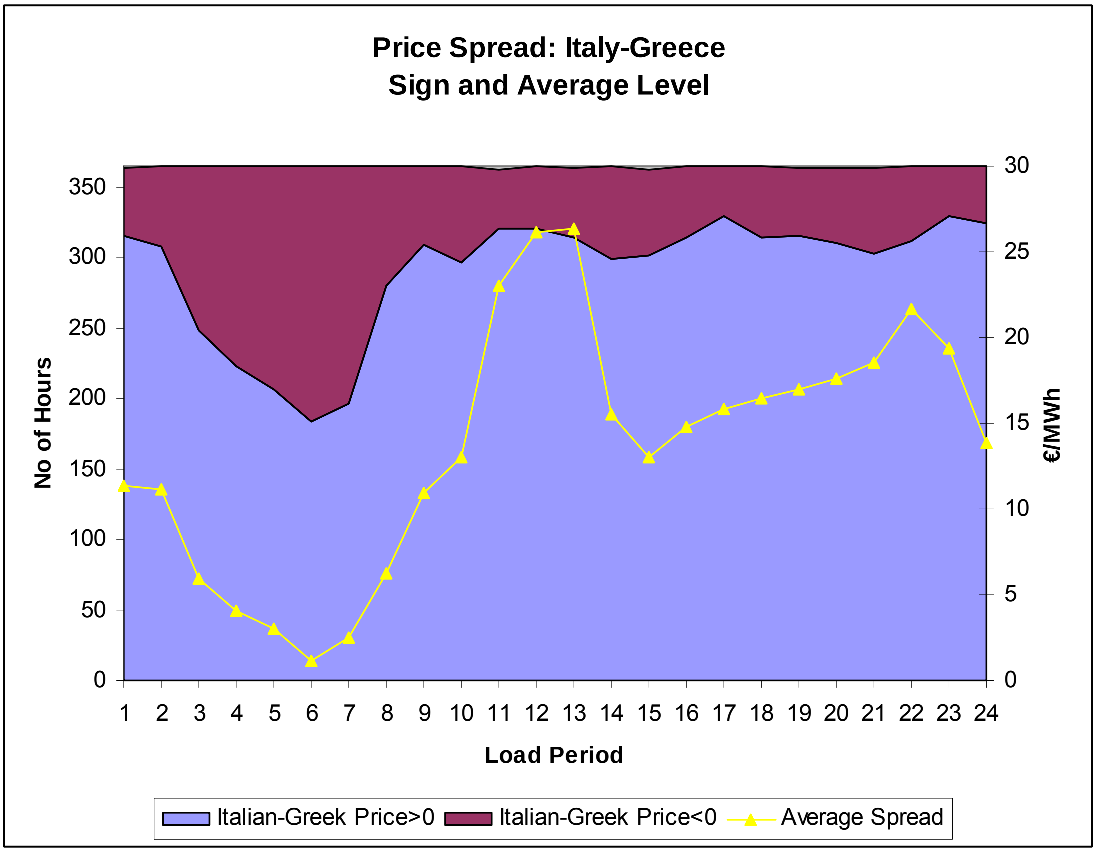

Figure 7. Average hourly spread and number of hours that a positive or negative spread occurred.

Figure 6 above displays average hourly quantities traded and the number of hours that exports or imports were dominant. Figure 7 displays the average hourly spread and the number of hours that a positive or a negative sign appeared over 2009. Overall, the hourly average spread varied from 1.16-11.6 €/MWh in off-peak hours and amplified to 13-26 €/MWh in peak hours, reaching maximum values of 130 €/MWh. These values imply substantial profits for exports to Italy over 2009 as well as potential profits for imports to Greece, whenever the sign reversal of the spread occurred and to the extent that this could be anticipated. As a representative price index in adjacent northern countries has not emerged yet, Romanian prices are often used as a plausible proxy. These prices exhibited a large discount, normally of 5-20 €/MWh relatively to Greek prices in 2009, which, given regional similarities, explains the large inflows to Greece from northern borders.

Figure 8 displays the allocation of interconnection trading in 2009 and its evolution relatively to 2008. As discussed above, the main patterns that emerged are a) a strong increase in export activity, occurring in the interconnection with Italy, and b) stability in total imports, with a different allocation however, as inflows from FYROM more than tripled, while imports from Bulgaria declined by 27%. This re-direction of imports from Bulgaria to FYROM could relate to adjustments in tariffs, regulatory or business incentives. It is remarkable that imports from Italy diminished from 1.76 TWh in 2008 to 0.31 TWh, while exports escalated from 0.18 TWh to 2.19 TWh in 2009. This reversal represents traders' reaction to the price spread, which appeared quite erratic in 2008 -as Greek prices attained very high levels, partially due to a dry year-, but exhibited, over 2009, fairly stable signals (particularly over peak periods) and sustained high levels, as Greek prices collapsed - partially due to a particularly wet year, as well as global trends in fundamentals.

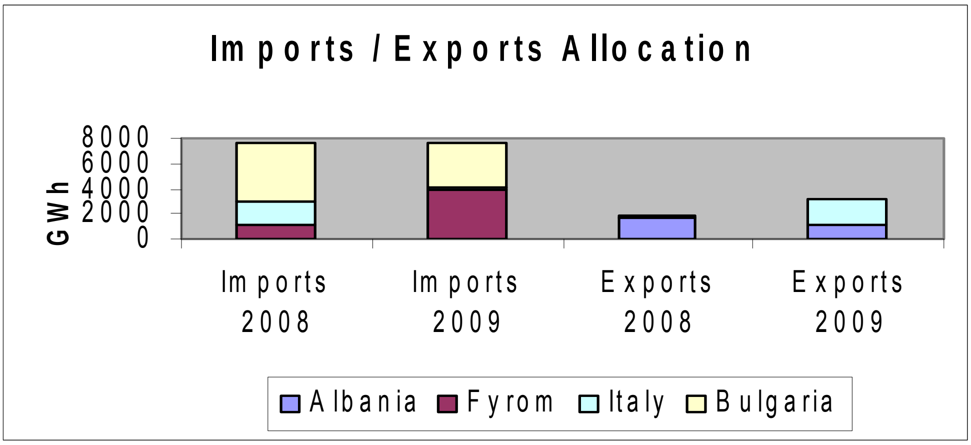

Figure 8. Profile of import and export trading in 2009 compared to 2008.

Up to 15 companies were active in the interconnection with Italy and significantly fewer, usually around 5, in the northern borders. Despite its substantial growth, export activity from Greece has not reached its full economic or technically feasible potential, as the Auction Rules for determining ATC on interconnections concerning exports from Greece pose a constraint related to security of supply in Greece. In a recession period, and given the sustained spreads with Italy, such obstacles should be reduced as much as possible. No significant changes occurred in the rules for cross-border electricity trading in 2009.

Overall, integration with adjacent Balkan countries was subject to trading obstacles due to the lack of appropriate implementation of Regulation 1228/2003, especially regarding capacity allocation mechanisms and transparency issues.

3.2.2. **Description of the retail market**

Table 10 and 11 present the consumption of end-user customers in 2009 by category and voltage level, for the interconnected system and the non-interconnected islands respectively.

Total consumption at the transmission system level (for the interconnected system only) was 52.8TWh, down by nearly 7% from 2008. PPC remained the dominant supplier (99.4% of the total volume). Nevertheless, some activity in the retail market has developed during 2009, where two independent suppliers, namely Verbund Austrian Power Trading S.A. and Aegean Power S.A., represented 0.46% and 0.09% of total volume, respectively. By the end of 2009, nearly 5% of customers connected to the medium voltage network had switched supplier. The percentage in the low-voltage market segment was still insignificant.

Interconnected System (GWh)									
Voltage	Year	Residential	Industrial	Commercial	Agricultural	Public	Traction	Mines, Pumping	Total
LV	2007	16235.0	1315.4	9949.1	2259.9	1496.1			**31255.5**
	2008	16369.6	1271.3	10258.8	2437.7	1.581.3			**31918.7**
	2009	16367.6	1191.8	10240.3	1931.9	1676.0			**31407.7**
MV	2007		5821.1	3703.2	376.9	942.1	142.0		**10985.3**
	2008		5675.6	4313.0	418.0	910.0	152.7		**11469.3**
	2009		5127.3	4145.5	366.1	916.9	142.2		**10697.9**
HV	2007		7731.7					2189.5	**9921.2**
	2008		7553.4					2157.6	**9711.0**
	2009		6005.9					1357.7	**7363.6**
Total	**2007**	**16235.0**	**14868.2**	**13652.3**	**2636.8**	**2438.2**	**142.0**	**2189.5**	**52162.0**
	2008	**16369.6**	**14500.3**	**14571.8**	**2885.8**	**2491.3**	**152.7**	**2157.6**	**53099.0**
	2009	**16367.6**	**12325.0**	**14385.7**	**2298.0**	**2592.9**	**142.2**	**1357.7**	**49469.2**

Table 10. Electricity consumption for the interconnected system

(Source: PPC; data refer to metered consumption at customer site)

Non-interconnected islands (GWh)									
Voltage	Year	Residential	Industrial	Commercial	Agricultural	Public	Traction	Mines, Pumping	Total
LV	2007	1722.3	123.8	1667.9	211.8	279.9			**4005.7**
	2008	1755.9	123.3	1717.8	215.9	284.2			**4097.1**
	2009	1763.0	118.4	1696.1	185.9	290.4			**4053.8**
MV	2007		207.7	556.0	32.7	179.2			**975.6**
	2008		204.5	600.0	33.5	185.1			**1023.1**
	2009		192.7	612.2	30.4	191.6			**1026.9**
Total	2007	**1722.3**	**331.5**	**2223.9**	**244.5**	**459.1**			**4981.3**
	2008	**1755.9**	**327.9**	**2317.8**	**249.3**	**469.3**			**5120.2**
	2009	**1763.0**	**311.0**	**2308.3**	**216.3**	**481.9**			**5080.6**

Table 11. Electricity consumption in the non-interconnected islands

(Source: PPC; data refer to metered consumption at customer site)

At the end of 2009, apart from PPC SA, supply licenses have been granted to 56 other companies (see list in Appendix II). None of these companies are affiliated to the TSO or DSO businesses. It should be noted that, until recently, independent suppliers were mainly active in trading rather than retail supply. 2009 saw increased activity in the retail market, demonstrated by the volumes purchased by suppliers in the wholesale market.

Supply activities still follow the *Supply Code*, which was issued in 2001. A new Code is to be published in 2010.

In order to best monitor the electricity market, RAE requested the following information from all holders of Supply Licences in 25/11/2009: a) financial data for 2008 (in order to verify financial status of Suppliers), and b) supply contracts offered to consumers in the retail market.

Of the 57 licence holders, 30 have submitted the requested financial data and 4 among these 30 have submitted their supply contracts. 10 out of these 30 licence holders replied that they have not been active in the retail market to date.

RAE is currently reviewing the data submitted. Regarding the content of the supply contracts, what the Regulator mainly noticed is the inadequacy of information that contracts include regarding consumers charges, the way that these charges are being modified, and the possibility of the Transmission System Operator to ask for the payment directly from the Consumer, in the case these debts are not paid to the Supplier. Further work on the credit risk monitoring of the Suppliers should be undertaken during 2010.

As far as the interaction of the Suppliers with the HTSO and the DSO is concerned, switching procedures including the set of information that needs to be provided by the parties involved and all matters relevant to the representation of end-user consumption by suppliers for the purposes of settlement, are also covered by the 2005 Grid and Market Operation Code (and subsequent amendments) and by the “Manual for the management of metering and the periodic settlement between Suppliers serving customers connected to the distribution network”, given that the draft Distribution Code has not yet been adopted. In practice, the switching process is initiated by the new supplier, with the submission to the DSO of a declaration requesting to assume representation of the consumer's meter. The DSO is given 34 days to process the request and effectuate the supplier switch. The DSO cannot be requested to effectuate a supplier switch in less than 30 days from its submission. The former supplier cannot prohibit or otherwise interfere with a supplier switch. Moreover, he is obliged to provide, upon customer request and within 14 days, metering data that the latter may need in relation to the switch.

Identification of the metering/delivery points of electricity on the distribution network is effected by means of code numbers uniquely assigned to the following: a) the consumer supply point and b) the meter installed on this supply. For validation purposes, the meter number as well as the consumer details should be included in the notice submitted to the DSO for switching supplier. Both numbers above are readily available to the consumer on the electricity bill. Medium voltage eligible customers may be supplied simultaneously by more than one supplier. In this case, an agreement needs to be signed between the suppliers, defining the allocation rules among the suppliers of the supplied energy. The TSO ensures that the entire metered energy consumption is fully allocated to the suppliers and/or the eligible customer. The revision of the Supply Code will introduce more favourable switching conditions for consumers.

Details on the regulations governing the Supplier of Last Resort have not yet been determined.

Retail price developments

There was no change to the regulated retail tariffs of PPC within 2009. Independent suppliers were able to offer discounts in the range of 5-15% in specific retail market segments demonstrating higher levels of profitability, due to cross-subsidies in the regulated tariffs (mainly medium and large commercial customers, as well as large domestic customers).

In order to remove the existing price distortions in the retail market, PPC was requested by RAE and the Ministry of Development in November 2007 to submit within 2008, proposals for regulated tariff structures in order to achieve:

- unbundling of the various services (generation, transmission, distribution, supply)
- cost reflectivity and removal of cross-subsidisation between consumer categories
- choice of tariff structures which better match consumer load characteristics in the most economic way
- incentivisation of consumers to improve their load characteristics
- transparency in order to remove barriers to new entrants
- maximisation of the long-term benefit to the consumer and generally consumer protection
- optimisation of the use of the existing assets
- coverage of Public Service Obligations (PSOs)
- ensuring the continuous security of supply.

The unbundling of tariffs for the various services was achieved in 2009. Various Ministerial Decisions were issued regarding the regulated tariffs (networks, PSO), which led to the final unbundling of the retail tariff elements. Estimated average tariff breakdown by element is shown in Table 12 to Table 14.

In November 2009, PPC also submitted a proposal for new categorisation and structures for the competitive element of the retail tariffs, in order to conclude the required unbundling of their tariffs. The final approval of the new tariffs, which are expected to encourage healthier competition in the retail electricity market, while covering all underlying costs of supply, is expected to be completed within 2010.

Switching

2009 saw increased activity regarding supplier switching in the retail electricity market. The main incentive for switching from the incumbent PPC to alternative suppliers was the price discounts offered. On the other hand, the switching rates would have been higher, had consumers not been influenced in their decision by the bad experience of delays and problems encountered in the early days of the development of competition in the telecommunications market. Electricity consumers feared similar delays in supplier switching and even the danger of electricity disconnection, and considered that the savings offered were not enough to incentivise them to take the risk, even though this risk was based more on perception rather than actual facts.

Medium	Customers	Sales	Total retail charge	Transmission charge	Distribution charge	PSO	Total regulated charge	Total competitive charge
			Average charge					
Voltage	Number	MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh
Commercial LF>50%	2,923	3,738,168	97.16	4.79	6.43	9.64	20.86	76.30
Commercial LF<50%	3,098	2,060,256	109.49	6.53	9.06	9.64	25.23	84.26
Industrial LF>50%	1,027	3,959,817	78.14	4.79	5.48	7.75	18.02	60.12
Industrial LF<50%	2,200	1,509,893	95.41	10.15	8.80	7.75	26.71	68.70
Agricultural	523	397,372	40.56	0.00	0.00	3.80	3.80	36.76
Total	**9,771**	**11,665,506**	**90.73**	**5.63**	**6.66**	**8.55**	**20.85**	**69.88**

Table 12. Estimated average charges for MV customers in 2009

Source: RAE estimates, PPC data excluding taxes

Domestic	Customers	Sales	Total retail charge	Transmission charge	Distribution charge	PSO	Total regulated charge	Total competitive charge
			Average charge					
Single phase 4monthly demand between	Number	MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh
0-800	2,456,166	2,657,415	82.32	7.68	27.77	0.00	35.45	46.87
801-1600	1,552,613	5,521,922	104.84	5.98	21.60	10.10	37.68	67.16
1601-2000	314,462	1,738,808	111.88	5.72	20.64	10.80	37.15	74.73
2001-3000	214,459	1,559,718	140.20	5.60	20.22	19.20	45.02	95.17
>3001	43,342	497,028	159.38	5.47	19.74	26.60	51.81	107.58
3-phase 4monthly demand between								
0-800	360,572	464,218	99.39	11.72	42.48	0.00	54.20	45.19
801-1600	392,248	1,427,475	114.96	7.54	27.25	10.10	44.88	70.08
1601-2000	97,787	546,278	124.94	6.74	24.36	10.80	41.90	83.04
2001-3000	89,598	668,898	148.57	6.38	23.04	19.20	48.61	99.96
>3001	41,819	599,694	169.09	5.93	21.42	26.60	53.96	115.13

Table 13. Estimated average charges for domestic customers in 2009

Source: RAE estimates, PPC data excluding taxes

			Average charge					
	Customers	Sales	Total retail charge	Transmission charge	Distribution charge	PSO	Total regulated charge	Total competitive charge
Commercial	**Number**	**MWh**	**€/MWh**	**€/MWh**	**€/MWh**	**€/MWh**	**€/MWh**	**€/MWh**
Small	1,255,241	6,089,902	146.46	7.77	23.94	12.80	44.51	101.95
Medium without reactive power metering	96,417	3,220,451	135.00	6.61	23.01	12.80	42.41	92.58
Medium with reactive power metering	28,409	3,335,869	127.33	6.49	23.17	12.80	40.19	87.14
Zonal/daytime charge	14,330	186,405	193.57	7.23	22.58	12.80	42.61	150.96
Zonal/ nighttime charge		155,843	59.94	0.00	0.00	0.00	0.00	59.94
Industrial								
Small	45,954	255,492	135.70	7.73	23.82	12.08	43.63	92.08
Medium without reactive power metering	9,768	266,481	123.22	6.83	24.09	12.08	43.00	80.22
Medium with reactive power metering	8,576	688,504	121.95	6.96	25.96	12.08	42.74	79.21
Zonal/ daytime charge	2,866	49,413	169.41	7.23	22.58	12.08	41.89	132.20
Zonal/ nighttime charge		57,019	51.64	0.00	0.00	0.00	0.00	51.64
Agricultural	207,710	2,117,006	48.43	0.00	0.00	4.41	4.41	44.02

Table 14. Estimated average charges for non-domestic LV customers in 2009

Source: RAE estimates, PPC data excluding taxes

Consumers

A total number of 324 documents on complaints/inquiries[7] concerning electricity and gas were registered to RAE, either directly by individual consumers or through other responsible consumer bodies/organisations. Although RAE does not have a legal mandate to act as a dispute settlement body, between service providers and individual consumers, it investigates all submitted complaints and responds to all inquires addressed to RAE. 44% of the documents, i.e., 143 documents, pertained to electricity.

Complaint evaluation process involves two main stages: in the pro-hearing stage, RAE may request information and relevant documents from service providers. Due to the absence of a Distribution Network Code and to the inadequacies of the obsolete Supply Code in force, usually a certain change in behaviour or action may be recommended as a result of the evaluation. A hearing stage could follow, where RAE may:

- order the service provider to cease any behaviour violating consumer rights
- impose a financial penalty to the service provider for non compliance with regulations or with the above mentioned order.

The majority of complaints are not resolved and consumers often have to appeal to a court.

Under the context of market monitoring, RAE's main role is to collect and analyse complaints data in order to identify any underlying market malfunctioning, with a scope to set up rules and regulations for protecting consumers. Other bodies, directly responsible for the handling of consumer complaints, are a) the Greek Ombudsman, b) the Hellenic Consumer's Ombudsman, which is a public Independent Authority with an institutional role in dispute resolution, c) the General Consumer's Secretarial of the Ministry of Development, and d) non-governmental consumer organizations. In most cases, the recommendations of these bodies are not binding to service providers and complaints are, thus, not settled.

Despite the absence of a formal definition, RAE recognises/treats a consumer complaint in relation to the provision of electricity, as follows: the written expression of a consumer's dissatisfaction, which is addressed to the electricity provider (supplier or distributor) or any other third party, to which, the consumer expects a response or resolution. A consumer inquiry is any written request for information or clarification or advice submitted by a consumer or any other third body in relation to the provision of electricity or gas or any other subject within the responsibilities of the Authority.

A table of statistics on complaint documents registered to RAE follows:

[7] Please note that the number refers to separate documents registered to RAE that concerned complaints and not individual cases.

Complaint category	%
Compensation claims for appliances damage due to electricity disturbances	30.8
Billing -Unacceptable high charges (Unjustified high meter readings, past period re-pricing after meter fault, etc)	22.2
Quality of electricity supply	17.1
Problems with electricity network installations	11.1
Connection /disconnection	6.0
Metering problems	5.1
Selling Price	5.1
Customer service	1.7
Pricing policy	0.9

Table 15. Electricity complaints/inquiries by nature

In the electricity sector, the majority of dissatisfied consumers was concerned with a) compensation claims for damage sustained to electric devices, due to problems in the quality of supply and b) high - unjustified billing issues. The dominant Supplier published an informative brochure on the protection of home appliances. The issue of the Distribution Code is of top priority.

Measures to avoid abuses of dominant power

As the Greek electricity market features one dominant player, PPC S.A., controlling about 95% of the generation market and 100% of the supply market, it was deemed important from the beginning to design a market that would facilitate the entrance of new participants and restrict the dominant market power of PPC.

The most important measure taken was the wholesale market design itself: the Grid and Market Operations Code (Code) describes a market where participation is mandatory (thus all energy is traded through it) and the market is cleared according to a specific and transparent unit commitment algorithm, taking into consideration a number of technical constraints of the generation units (like in PJM and a number of other markets in the US). The mandatory participation forced the incumbent to participate in the market and avoid exclusionary practices. Moreover, by taking into account in the algorithm the technical constraints of the units, which were called upon in the past by the incumbent affecting the operation of the market, the market clearing algorithm doesn't just clear the market, but also gives a good indication to the participants of what the real time operation of the units should be, in order to be efficient. This will also minimise the imbalance payments, when the corresponding rules become active, and facilitate the introduction of a balancing market in the future.

Moreover, the Code provides a number of additional procedures in order to prevent market abuse, protect the integrity of the market and strengthen the public confidence in it:

- Transparency of Information

  All data used by the TSO in the market clearing algorithm have to be published ex-ante, in order to assist the market participants in submitting their bids. Moreover, all market results have to be published after the clearing of the market.

- Techno-economic Declarations of generation units

  A techno-economic declaration has to be submitted by all generators, giving all technical characteristics for each generating unit, as well as information on fuel cost and other operational costs. The techno-economic declaration is compulsory, and there is a penalty clause for non- or false submission of the declaration.

- Periodical Hydro Usage Declarations

  On a weekly basis, owners of hydro units (currently only PPC) are obliged to submit a declaration for the forecasted mandatory hydro production to be injected in the market (due to irrigation, spilling and water supply). Moreover, on a monthly basis, owners of hydro units have to submit a report regarding the forecast management of hydro for the twelve months ahead.

- Unit Availability Declarations

  In case of an outage, generation license holders are obliged to submit, for each generating unit they own, a declaration of partial or total non availability due to technical reasons. The availability declaration is compulsory, and there is a penalty clause for non- or false submission of the declaration.

- Price Caps

  In order to avoid abuse of dominant power or market price manipulation, a regulated price cap is set for the bids. Its value is decided by the Minister of Development, following an opinion by RAE.

- Price Floors

  In order to avoid abuse of dominant power or market price manipulation, a regulated price floor is set for the bids of the generating units. For the thermal units, its value is equal to the minimum variable cost of the unit and it is calculated according the data provided in the techno-economical Declaration of the generator. For the hydro units, it is decided yearly by RAE, considering, amongst other factors, the hydro reserves in the reservoirs and the fuel prices of the thermal units.

The daily supervision of the operation of the market and the adherence to the aforementioned rules falls mainly in the responsibility of the market operator (HTSO). RAE has the more general responsibility of monitoring the developments of the electricity market and the overall market behaviour of the participants. RAE has the authority to ask any participant to submit to RAE published or confidential information, in order to investigate actions and practices followed by participants. In case of violation of the provisions of the Code, RAE has the authority to impose administrative sanctions (e.g. fines) against the licensees, including an opinion to the Minister of Development to revoke their license.

4. Regulation and Performance of the Natural Gas market

4.1. Regulatory Issues

4.1.1. Management and allocation of interconnection capacity and mechanisms to deal with congestion

During 2009, there was no change regarding interconnection infrastructure of the Greek transmission system with neighbouring gas systems, namely Bulgaria and Turkey.

There is still no integration between the Greek and the Bulgarian natural gas markets, mainly due to the fact that the pipeline transporting gas to Greece through Bulgaria is a dedicated transit pipeline, exempted from TPA rights, which apply to the rest of the Bulgarian national network. This is also the case for the transit pipelines upstream of Bulgaria. Furthermore, there is no integration between the Greek and the Turkish markets, since there is no clear TPA regime in the latter. Therefore, no physical or contractual congestion was experienced in both interconnectors during 2009.

Furthermore, during 2009 there was no gas transit on a regular basis through Greece. However, in January 2009, in the midst of the Russian – Ukrainian dispute, gas was supplied from the LNG facility on Revythoussa Island, Attica Bay, to Bulgaria through the Greek Transmission System. Physical backhaul flow of gas was effected through appropriate technical adjustments made at the metering station at Sidirokastro, at the Greek – Bulgarian borders. From a regulatory viewpoint, it has to be noted that the reverse flow was effected without any adjustments to the Standard Transportation Agreement already in place.

4.1.2. The regulation of the tasks of transmission and distribution companies

<u>Network Tariffs</u>

A. TPA tariffs

Compared to the previous year (2008), tariffs were simply adjusted for inflation. The actual TPA tariffs for 2009 are presented in the table below:

Tariff	Capacity Charge (€/peak day MWh/year)	Commodity Charge (€/MWh/year)
Transmission Tariffs 2009	568,251	0,279572
LNG Tariffs 2009	23,842	0,017989

Table 16. TPA tariff coefficients

DESFA SA (the Greek TSO) publishes in its website the current TPA tariffs, in both the Greek and English language (http://www.desfa.gr/default.asp?pid=102&la=2).

Ministerial Decision 4955/2006 with all amendments is published in the website of RAE, in both Greek and English.

B. Distribution tariffs

There were no changes in the scheme of gas distribution, performed by the three distribution companies currently active in Greece (hereinafter "EPAs"). EPAs are operating under a regime of exclusive right, for both the activities of distribution (DSO) and of supply of gas in their areas.

According to article 24 of the Gas Law, access to EPA's networks can be granted to other suppliers serving eligible customers with annual consumption of more than 100 GWh GCV of natural gas. The tariffs for accessing the EPA's distribution systems are approved by the Regulator (article 31 of the Greek Gas Law), in full compliance with the provisions of the Directive.

Tariffs for TPA in EPA's distribution systems were not set in 2009, since completion of accounting unbundling of the companies is a prerequisite. However, in the interim period, the tariffs for access to EPA's networks have been fixed according to the provisions of article 31.4 of the Gas Law.

Balancing

There were no changes in the scheme for balancing energy, as it was described in the 2009 National Report.

RAE approved in 2009 the annual balancing plan submitted by DESFA SA, which includes the estimates of the TSO regarding balancing gas needs and an evaluation of possible balancing gas supply sources for the year. According to the balancing plan, and in line with an interim provision of the Gas Law, the necessary quantities of balancing gas (in the form of LNG) were purchased from DEPA SA.

RAE also approved the balancing cost allocation scheme and the relevant shipper's charges for the year 2009, which include all costs arising from providing balancing services. The corresponding charges include:

- A fixed charge which covers the fixed costs of the TSO in providing balancing services.
- An energy charge corresponding to the cost of balancing gas procured by the TSO, according to the relevant balancing gas supply contract, which is the basis of the cash-out price (Daily Balancing Gas Price).

All balancing charges and the methodology of their calculation, as well as the Daily Balancing Gas Price, are published in DESFA's SA website in both Greek and English (http://www.desfa.gr/default.asp?pid=87&la=2).

4.1.3. **Effective Unbundling**

The unbundling situation in Greece, as well as the relevant provisions of the Gas Law and the forthcoming Licenses Regulation, has been presented in detail in the National Reports of 2008 and 2009. Below, separate sections provide recent developments for legal, functional and accounting unbundling.

Legal unbundling

There were not any changes regarding legal or ownership status of the TSO (DESFA SA)

The same stands for the three distribution companies currently operating in Greece (EPAs). Despite the fact that EPAs perform the combined activities of DSO and exclusive supplier in the areas covered by the respective concession, EPAs have no other legal unbundling obligation due to the special regime under which they operate, as acknowledged in article 28 of the Directive 2003/55/EC.

Functional unbundling

DESFA SA and future infrastructure operators:

All the provisions of the Authorisation Regulation regarding functional unbundling of DESFA SA and future operators, described in detail in the 2009 National Report, were finalized in 2009 following a public consultation procedure. The adoption of the Authorisation Regulation, by means of a Ministerial Decision in 2010, along with the relevant provisions of the Gas Law 3428/2005, provide a complete set of rules for functional unbundling.

Existing and future distribution concessions:

Existing gas distribution concessions are exempted from functional unbundling obligations (article 28.8 of the Gas Directive and article 21 of the Gas Law) and are only obliged to keep separate accounts for their gas distribution and supply activities.

For the three new distribution concessions that are planned, Commission Decision E(2008) 4773 also allows for a derogation from functional unbundling requirements and provides only for the obligation for accounting unbundling.

Accounting unbundling

In accordance with the provisions of the Gas Law (presented in the National Report 2008), DESFA SA, as well as the three EPAs, submitted the detailed rules for accounting unbundling within 2008 and are in the process of approval by RAE, while DEPA SA has not yet submitted the said rules. Therefore, unbundled accounts are expected to be published for the financial year 2010.

4.2. Competition Issues

The deployment of eligibility rights was completed on 15.11.2009, leaving only small consumers located in the concession areas to being non-eligible (for a detailed review, please refer to the National Report of 2009).

End-use eligible customers (i.e. excluding EPAs) represented at the end of 2009 nearly 90% of total gas demand in Greece.

As explained in the introductory note, DEPA SA remained the only gas importer in the country and the sole gas supplier to all eligible customers and the EPAs.

A case of refusal of third-party access to the Grid took place at the end of 2009, when an eligible customer attempted to import LNG for its own consumption. The TSO raised issues of contractual congestion and lack of sufficient regulatory tools to deal with the situation. RAE's position on the issue was that full TPA had to be provided to the interested party, and, accordingly, a strong recommendation was issued to the TSO. Nevertheless, access was never realised and, following a complaint submitted by the affected eligible customer, RAE initiated a formal investigation, due to be completed in 2010.

Notably, the investigation will include the issue of possible anti-competitive behaviour of the incumbent and, based on the findings, the case may be forwarded to the Hellenic Competition Commission for further investigation and action.

4.2.1. Description of the wholesale market

In 2009, DEPA SA remained the only importer of gas in the country and the sole supplier of gas in the Greek natural gas market.

The gas market is organised on the basis of bilateral contracts between suppliers and eligible customers and no organised wholesale market exists, thus, there is no published data available for wholesale prices. End-customer prices are only published by the gas distribution companies (EPAs).

The attempt of an eligible customer to supply its own gas at the end of 2009 was not successful, due to the reasons described above. However, it was proven that the LNG facility on Revythoussa Island remains the most prominent point for the entrance of new suppliers in the Greek gas market.

No storage facilities exist in the Greek natural gas system. The LNG storage tanks are only used for temporary storage of cargoes.

4.2.2. Retail market: Consumer complaints/inquiries

There are four end-user suppliers, namely DEPA SA and the three EPAs. DEPA SA owns 51% of each EPA, thus, by using the domination principle, DEPA holds a 100% share in the market.

There were no developments regarding the pricing methodologies used by EPAs in calculating end-user prices for different customer categories. Overall, average prices in 2009 were lower than 2008 prices, following the drop of oil-product prices. Some indicative annual average prices are presented below, for EPA Attica and EPA Thessaloniki:

€/MWh *	EPA Attica domestic	EPA Thessaloniki domestic	EPA Attica small commercial	EPA Thessaloniki domestic-commercial
2007 average	40.15	39.43	39.51	40.78
2008 average	55.50	48.93	60.08	50.39
2009 average	36.37	45.88	44.41	47.34

Table 17. Indicative annual average natural gas prices.
* end-user prices, net of VAT 9%

The minimum contract duration for households is usually one year, after which, there are no obligations (financial or other) for the customer who wishes to terminate its gas supply connection.

EPAs provide all the necessary information regarding end-user prices, per customer category, in their websites. Moreover, they provide telephone lines through which the customers can obtain information regarding prices, connection fees, connection details, etc.

Consumers

The consumers' complaints/inquires on gas were handled in the same way as the ones of electricity, by either the Regulator or the alternative dispute resolution bodies, described under the electricity section (3.2.2).

The 178 complaint documents registered to RAE pertain to the following:

Complaint category	%
Selling Price	53.4
Billing	12.2
Pricing policy	9.5
Problems with gas network installations	8.8
Connection /disconnection	8.8
Payment methods	3.4
Customer service	2.0
Metering problems	1.4
Compensation claim	0.7

Table 18. Gas complaints/inquiries by nature

The issue of the significantly increased price of natural gas, compared to the corresponding price of heating oil, in the geographical areas of competence of two (out of three) Gas Suppliers, has emerged as the most important consumer complaint during 2009. This was the result of the tariff methodology applied by the Supplier, under which, the price of gas is formed on the basis of prices of petroleum products and adjusted with a lag of six months. Thus, the price of gas introduced in the last quarter of 2008 was based on the very high international oil prices of petroleum products experienced in the second half of the same year. Since RAE is responsible for the post-verification of invoices and not responsible for the pre- determination or approval of gas prices, the Authority's actions were limited to: a) making a public announcement on clarifications about RAE's legal mandate and the nature of the specific problem; b) issuing a recommendation to Suppliers to inform consumers promptly and in detail on gas pricing methodology.

5. Security of Supply

5.1. Electricity

5.1.1. Supply - Demand Balance

Demand

The evolution of energy and peak power demand for the interconnected system for the years 2005 to 2009, as reported by the HTSO, is shown in the next table.

	2005	2006	2007	2008	2009
Electricity consumption excluding pump storage (GWh)	52500.8	53656.8	55253.4	55675.3	52436.5
Peak load (MW)	9635	9962	10610	10393	9828
Peak including curtailed load (MW)	9800	-	11110	-	-

Table 19. Energy and peak power demand (2005-2009) for the interconnected system (Source: HTSO)

With the total demand in the non-interconnected islands amounting to 5080.6 GWh, the country's total consumption in 2009 was **57.5 TWh** (including about 3 TWh of losses). Since each of the non-interconnected islands is supplied by a small autonomous power system, a synchronised peak-demand cannot be calculated. It is also worth noting that about 0.6 TWh of RES production is injected to low and medium voltage and is, therefore, not being accounted for in the HTSO's balance presented in Table 19 and Tables 22-23.

Forecasts for energy and peak power demand for the years 2008-2012, as presented in the HTSO´s five-year plan for the development of the transmission system, were reported in last year's National Report. However, due both to the economic crisis and an unusually mild winter and cool summer, the actual consumption in 2009 was lower by about 7% from that of 2008, which was already below the one predicted under the "low" scenario. No updated forecast has been published yet by the HTSO.

Generating Capacity and Fuel Mix

On 31.12.2009, the total 12491.9 MW of total net generation capacity in the interconnected system were distributed as follows:

Plant type	Net installed capacity (MW)	%
Lignite	4808.1	38.49
HFO	718.0	5.75
GTCC	1962.1	15.71
Natural gas – other	486.8	3.90
Hydro plants	3016.5	24.15
RES and small Cogeneration	1058.4	8.47
Large-scale CHP	334.0	2.67
Other Cogeneration	108.0	0.86
Total	**12491.9**	**100.00**

Table 20. Installed capacity as of 31.12.2009 in the interconnected system.

Concerning RES, the licensing progress per technology is presented in the following Table. By 31.12.2009, the RES capacity installed in the interconnected system amounted to approximately more than 1GW (large hydro not included).

RES TYPE	COMMERCIALLY OPERATING		WITH INSTALLATION LICENSE		WITH GENERATION LICENSE		RECALLED		APPLICATIONS FOR GENERATION LICENSE	
	MW	%	MW	%	MW	%	MW	%	MW	%
WIND	1026.3	84.4	1139.3	83.7	7362.6	83.6	544.6	81.5	49764.3	84.8
BIOMASS	33.9	2.8	21.2	1.6	97.8	1.1	24.5	3.7	1193.0	2.0
GEOTHERMAL	0.0	0.0	0.0	0.0	8.0	0.1	0.0	0.0	340.5	0.6
SMALL HYDRO	149.6	12.3	90.0	6.6	644.8	7.3	98.0	14.7	2169.8	3.7
PVs	5.9	0.5	109.2	8.0	393.1	4.5	0.7	0.1	3038.6	5.2
OTHER	0	0	2.1	0.2	304.2	3.4	0	0	2198.2	3.7
TOTAL	**1215.8**	**100.0**	**1361.8**	**100.0**	**8810.4**	**100.0**	**667.9**	**100.0**	**58704.3**	**100.0**

Table 21. Licensed RES plants as of 31.12.2009 in the interconnected system

Regarding the fuel-mix in 2009, the country’s dependency on fossil fuels, but also on imports, is depicted in Table 22.

	Interconnected system		Non-interconnected islands		Total	
	TWh	**%**	**TWh**	**%**	**TWh**	**%**
Lignite	30.54	57.82			30.54	52.24
Fuel Oil	1.70	3.21	5.00	88.65	6.70	11.46
Natural Gas	9.38	17.75			9.38	16.05
Large Hydro	4.96	9.38			4.96	8.48
RES	1.88	3.57	0.64	11.35	2.52	4.31
Net Imports	4.37	8.27			4.37	7.48
Total	**52.82**	**100.00**	**5.64**	**100.00**	**58.46**	**100.00**

Table 22. Generation Fuel Mix at the end of 2009

(Source: HTSO & PPC's Islands Network Operations Department)

The fuel-mix for the non-interconnected islands is also worth mentioning: about 90% of the electricity is produced by HFO and LFO units. PPC S.A. is the only supplier and generator (from thermal plants) on these islands (see Section 3.1). On the other hand, the percentage of RES has grown to over 11% in non-interconnected islands, as compared to a 3.57% on the mainland. More than 99% of the RES installed capacity on the islands comes from wind plants. As explained extensively in last year's Report, RAE strongly favours the interconnection of, at least, a number of the islands to the main system, which, according to studies, may be amortized within a few years. Through the interconnection, the islands' security of supply in the long-run will be ensured, while their excellent RES potential will be further exploited.

Finally, it is interesting to observe the difference in fuel mix in the interconnected system between 2008 and 2009, as presented in Table 23 below.

	2008 (TWh)	**2009 (TWh)**	**% difference**
Lignite	29.87	30.54	2.24
Fuel Oil	3.51	1.70	-51.57
Natural Gas	13.33	9.38	-29.63
Large Hydro	2.97	4.96	67.00
RES	1.57	1.88	19.75
Net Imports	5.61	4.37	-22.10
Total	**56.87**	**52.82**	**-7.12**

Table 23.Change in fuel mix between 2008 and 2009
(Source: HTSO)

There are no forecasts currently available for the fuel mix in the following years.

5.1.2. **Transmission**

Transmission system development

According to the Grid & Market Operation Code, HTSO is responsible for the development of the transmission system on the mainland and on the interconnected with the transmission system islands. The set of criteria applied by the HTSO in planning the development of the transmission system aims to achieve, at all times, the transmission of electricity in a secure, reliable and most economic manner, by applying transparent, unbiased and non-discriminatory criteria, while taking into account the principle of covering demand, new generation in the system, and the interconnection needs with other systems. In this framework, HTSO elaborates and publishes annually the five-year plan for the development of the interconnected transmission system (*Transmission System Development Study*), which is approved by the Minister of Development following RAE's opinion and the views of the Owner of the transmission system (PPC). In this plan, the various development projects are specified, as well as the relevant timeframes and estimated costs.

As far as congestion is concerned, the steady-state system security is evaluated using scenarios with forecast demand over a 5-year period, in order to assess the ability of the system to serve the expected load, to identify potential weak points, and to determine the new system development projects necessary to secure reliable and economic operation. Additionally, a market splitting mechanism is to be introduced in the Day Ahead wholesale market mechanism on January 1st, 2010. This mechanism, based on a two-operational zone consideration of the Greek System, is expected to provide an accurate evaluation of the cost of internal congestions.

Transmission system projects

Major new projects in the transmission system for the following years, according to the TSO's plan, are:

- Expansion of the 400 kV transmission system to the northeast part of the interconnected system for the interconnection of the Turkish system with Greece, as well as the accommodation of generation by new wind parks and thermal power stations. The full project will be operational by the year 2011.
- Expansion of the 400 kV transmission system to the south part of the interconnected system. Three (3) new EHV substations will be erected for this purpose in the Peloponnesus region. By the year 2012, a large part of this project is expected to be in operation. The power reinforcement of this area will provide increased security of supply, as well as additional transmission capacity for new RES projects in Peloponnesus.
- Connection of the Cyclades islands to the interconnected system through a DC or AC submarine link. The aim of this project is, apart from increasing the security of supply of these islands, to also reduce the PSO charges for their supply and to transfer the power from local wind parks to the interconnected system. The project is planned to commence in 2010.

New transmission projects are frequently delayed due to: (a) difficulties in project siting, (b) environmental licensing, and (c) local opposition.

Interconnections

Considering interconnection capacity, a major increase in the northern interconnections of Greece took place in 2009. This capacity increase was due to: a) the upgrade of a 150 kV line between

Greece and FYROM to 400 kV (completed in 2007), and b) a new interconnection between Bulgaria and FYROM (400 kV line Skopje – Stip – C. Mogila).
The two major interconnection projects underway are the following:

- Interconnection with Turkey
- New interconnection with Bulgaria: An agreement has been signed between Greece and Bulgaria for the construction of a second interconnection. The relevant studies are underway.

5.2. Gas

This section contains information in accordance with Directives 55/2003/EC and 2004/67/EC. All data referring to gas quantities are provided in both units of Mtoe (based on gas with a HHV of 9600Kcal/Nm^3) and bcm (at 15°C).

5.2.1. Current levels of gas consumption and expected future demand

The demand for Natural Gas in 2009 was 3.54 bcm, out of which approximately 75% served the Power Generation Sector, as shown in Table 24.

Year 2009	bcm @ 15°C	Mtoe (HHV)
Power Generation	**2.20**	**2.00**
Industry & HP customers	**0.88**	**0.80**
Commercial & Domestic	**0.47**	**0.43**
Total	**3.54**	**3.23**

Table 24. Sectoral demand in 2009

During 2010, gas demand from the power generation sector is expected to start rising again, as indicatively presented in Table 25 below. Commercial and domestic demand is expected to increase steadily according to the expansion plans of the Gas Distribution Companies (GDC's). Expected demand for the next three (3) years is presented below in Table 25 (RAE's estimates) and 26 (DESFA's estimates).

	2010		2011		2012	
	bcm	**bcm**	**bcm**	**Mtoe**	**Bcm**	**Mtoe**
Power Generation	2.68	2.44	3.01	2.74	3.22	2.93
Industry	0.88	0.80	0.88	0.80	0.88	0.80
Commercial Domestic	0.50	0.46	0.58	0.53	0.66	0.60
Total	**4.06**	**3.70**	**4.47**	**4.07**	**4.76**	**4.33**

Table 25. Expected future demand (RAE's estimates)

	2010		2011		2012	
	bcm	**Mtoe**	**bcm**	**Mtoe**	**Bcm**	**Mtoe**
Power Generation	2.26	2.06	2.41	2.19	2.53	2.30
Others	1.47	1.34	1.63	1.49	1.81	1.65
Total	**3.73**	**3.40**	**4.04**	**3.68**	**4.34**	**3.95**

Table 26. Expected future demand (DESFA's estimates)

The values of Table 25 are RAE estimates, considering:

- the submitted expansion plans of the 3 GDC's currently operating in Greece,
- the forecasts of the sole supplier of Natural Gas, DEPA S.A.,
- the expected introduction of new gas-fired generation capacity, and
- the electricity demand forecasts for the next 3 years, within the current economic environment.
- high hydraulicity through 2012
- average to high availability of energy for exports to Greece from the southeast region.

The demand outlook for the next ten years can be very risky and inaccurate, particularly due to substantial uncertainties on global issues such as the EU ETS, the international oil prices, as well as domestic issues, such as the participation of Coal and Renewable Energy Sources into the energy mix within this time frame. Given these uncertainties, we provide three (3) different assessments, one coming from DEPA S.A., assuming business as usual and increased sales, and two different figures based on a Long-Term Planning study (LTPS), published in 2008 by the Ministry of Development, as well as the *Annual Report on the Long-Term Energy Plan*, published in 2009 by the *National Energy Strategy Council* . The data refer to five year intervals, extending to 2020. The presented data refer to the period between 2015 and 2020.

Scenarios		2015		2020	
		bcm	Mtoe	Bcm	Mtoe
1	DEPA S.A.	8.5	7.8	9.3	8.5
2	LTPS (2007) 2nd scenario[1]	6.8	6.2	7.2	6.5
3	LTPS (2009) Base Case[2]	7.5	6.8	7.5	6.8

Table 27. Ten year outlook

[1] *Increased RES and CO_2 abatement*
[2] *Annual Report on the Long-Term Energy Plan, 2009 National Energy Strategy Council*

5.2.2. **Supply - Demand Situation**

Indigenous production during 2009 was zero in Greece. Currently, the sole supplier in the NGTS, DEPA S.A., imports gas primarily through long term contracts from 3 different sources, namely Russia, Algeria (LNG) and Turkey. In 2009, the share of LNG increased considerably, as several spot LNG cargoes were unloaded at the LNG Terminal of Revythoussa Island, supplementing the quantities supplied via long-term contracts. Figure 9 shows the Natural Gas sources and their participation to the total imported quantities, as reported by the TSO. The aggregate of the contracted annual quantities according to the three existing supply contracts is shown in Table 28.

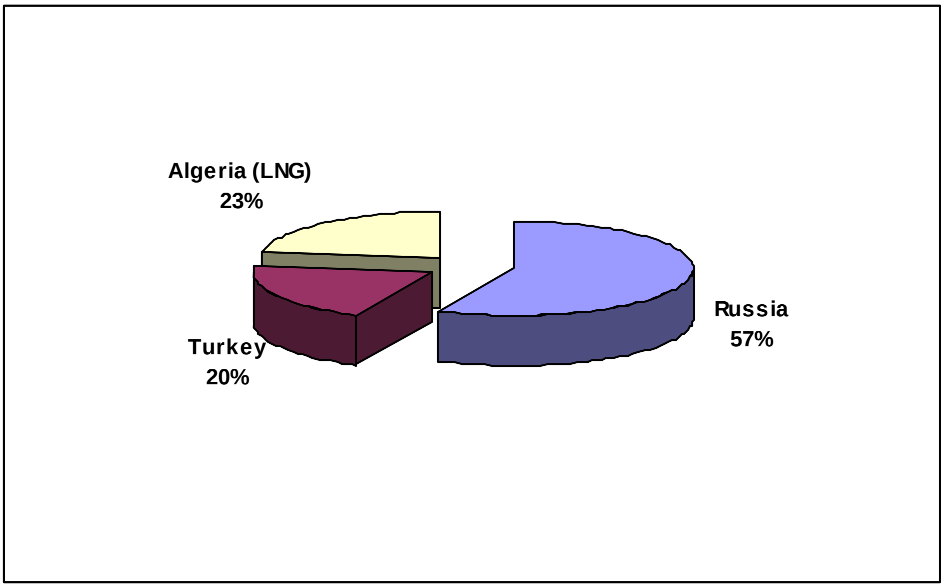

Figure 9. Natural gas sources

	bcm @ 15°C	Mtoe (HHV)
Up to 2009	4.1	3.7
After 2009	4.4	4.0

Table 28. Natural gas contracted annual quantities

Table 29 presents the anticipated supply – demand balance for the next three years, based on the expected demand and the existing long-term supply contracts. Because of the revised, significantly lower gas demand forecasts, existing Supply contracts are expected to meet demand through 2011.

	2010		**2011**		**2012**	
	bcm	**Mtoe**	**bcm**	**Mtoe**	**bcm**	**Mtoe**
Demand	**4.06**	**3.70**	**4.47**	**4.07**	**4.76**	**4.33**
Supply Contracts	**4.1**	**3.7**	**4.4**	**4.0**	**4.4**	**4.0**
Supply Gap	**0**	**0**	**0.07**	**0.07**	**0.36**	**0.33**

Table 29. Expected Supply-Demand balance

Figure 10 below shows the expected demand - supply balance projected to 2018, according to the scenarios presented in Table 27. The demand curve corresponds to DEPA's demand forecast of this table.

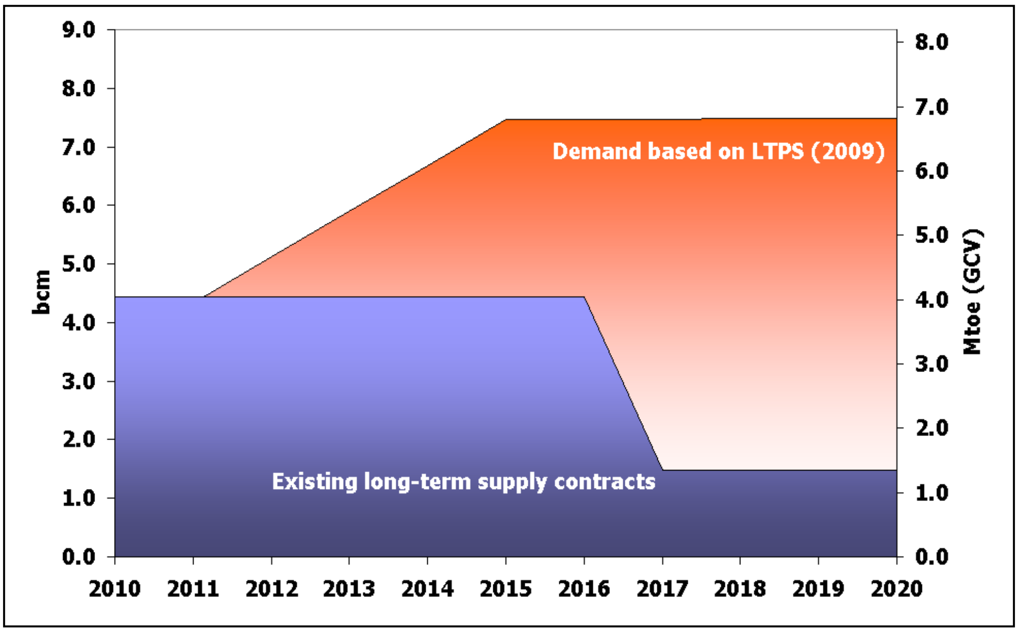

Figure 10. Natural gas supply-demand balance (10-year forecast)

5.2.3. **Quality and level of maintenance of the networks**

The TSO, being responsible for operating, maintaining and developing the NGTS, follows a regular cleaning and internal inspection program for the pipeline network, by means of cleaning pigs, in order to ensure the good operating condition of the network. Meter runs and the LNG terminal feature redundant systems, minimising the impact of component malfunction.

5.2.4. **Emergency measures**

Load shedding is the primary measure foreseen in the event of an emergency. According to the provisions of Law 3428/2006, the TSO enters into contracts with customers which choose to be interruptible, and by default with all dual-fueled power plant operators.

Load shedding is implemented according to a priority list. On top of the list, which includes all customers, are power installations with dual-fuel capability and other interruptible customers that have entered into supply-interruption contracts with the TSO. Last on this list are domestic customers. This, being a demand measure, is primarily aimed at satisfying peak demand, as well as covering an eventual short-term supplier shortfall. Security of supply in the long term will need to be assessed in line with the provisions of the new Regulation on Security of Supply. Possible alternatives include the following:

- supplementary LNG storage space on Revythoussa Island and elsewhere
- underground storage facility
- extension of the Dual Fuel obligation to all NG fired power plants
- operational Balancing Agreements with adjacent TSOs
- new interconnections with Bulgaria and Italy.

5.2.5. **Import capacity**

The Hellenic Gas Transport System has 3 Entry Points, two at the North and North-eastern borders - Sidirokastro and Kipoi - connecting with the Bulgarian and Turkish gas networks, respectively, and one at the Southern part, where gas from the Revythoussa LNG terminal is injected to the System.

Table 30 lists the current entry capacities. Annual quantities are derived from maximum hourly flow, considering a load factor of 90%.

Entry points	Theoretical [1]		Actual [2]	
	bcm	**Mtoe**	**bcm**	**Mtoe**
Kipoi	7.1	6.5	3.38	3.08
Sidirokastro	5.5	5.0	1.94	1.76
AG. Triada (LNG Terminal of Revithoussa)	4.8	4.4	0.93	0.85
Total	**17.4**	**15.8**	**6.25**	**5.69**

Table 30. Natural gas entry point capacities

The capacities in column [1] refer to the maximum technical capacity at the border, according to the TSO, without considering either the upstream network capacity, or the downstream constraints. In contrast, data in column [2] provide the capacity published by the TSO, based on upstream and downstream network restrictions. The LNG terminal annual throughput is based on the assumption of an (annual) load factor of 40%, which corresponds to a ship arrival (with a capacity of 75,000 m3) every 8 days.

Table 31 below lists the TSO's investment plans, which aim to add import capacity to the NGTS.

Project	Realization by
Compressor Station	2011
3rd LNG Tank at Revithoussa	approx. 2014

Table 31. Natural gas TSO investment plans

An important investment project still to be approved, involves the expansion of the Revythoussa LNG terminal's storage capacity through the addition of a 3rd LNG tank. This project is still in the conceptual phase, but we expect that submission to RAE for approval will take place soon. In any case, project realisation is expected around 2014.

To RAE's knowledge, there is no other forthcoming production capacity investment, planned within the Greek territory.

5.2.6. **Security of supply standards**

No new measures were introduced during 2009 and the implementation of the supply-interruption contracts has been delayed by the TSO, while awaiting the final provisions of the new Security of Supply Regulation. Our conclusions, expressed in the 2009 National Report are still valid, and we repeat them below.

Law 3428/2006 does not make explicit reference to Security of Supply Standards. However, the whole matrix of provisions seeks to provide uninterruptible supply of Natural Gas to all uninterruptible customers during a supply interruption event, which may extend to a 5 day loss of all gas supplies from either one of the three entry points of the NGTS (N-1 criterion for 5 days).

The provisions include the following:

- the Natural Gas-fired power plant obligations regarding backup fuel
- the Load Shedding Plan (according to the interruption priority list), prepared by the TSO (recently submitted to DG TREN)
- the supply-interruption contracts provided for in the Law and quoted in paragraph 5.2.4 of the present Report
- the Security of Supply levy for the remuneration of the interruptible customers who use alternative, higher cost, fuels.

Supply to domestic and other small customers is safeguarded in the event of a more extensive supply shortfall, by shedding further loads according to the interruption priority list. This is part of the Operating Code, which is in the final drafting stages.

The obligations of power plants have recently been modified, granting the option between a) maintaining dual-fuel capability, with liquid fuel stored on site, and b) maintaining five days worth of gas in a storage facility. While this change is under examination, due to the unavailability of storage space at the LNG terminal for this purpose, provisions granting a reduction of the security of supply levy to customers who opt to enter into supply-interruption contracts are considered, in order to give incentives to power plant operators located on sites with port facilities or near refineries, to choose the dual-fuel option on site.

The above provisions present no impact to gas market players, since none is directed to Gas suppliers. These provisions are targeted to gas customers. All Natural Gas customers must pay a security of supply levy on an energy basis. The level of this levy has yet to be specified by RAE; however, it will probably be universal for all consumers, with specific reductions given to customers who have entered into supply-interruption contracts with the TSO.

5.2.7. **Storage capacity**

There are no underground storage sites in the NGTS. The storage capacity is limited to the only existing LNG terminal on Revythoussa Island, which features two tanks with a total capacity of 130,000 m^3 of LNG, equivalent to approximately 0.08 bcm. However, the terminal is designed to service a large fraction of future demand increase, and a scheme granting full TPA is foreseen in the forthcoming Grid Code. Only a small fraction – which is still to be specified - of the LNG tank volume will be earmarked for maintaining minimum reserves for system balancing and supplying protected customers in the event of an emergency.

The exporting capacity of the LNG Terminal is limited by the re-gasification capacity which, unlike the storage capacity, is significant (approximately 14 mcm/day).

5.2.8. **Extent of long-term gas supply contracts**

As already mentioned in Section 5.2.2, DEPA has concluded three long-term contracts for the supply of Natural gas from Russia, Algeria (LNG) and Turkey. The graph below lists the contractually available gas quantities in the 2014-2022 time period.

Figure 11. Contractually available Natural Gas quantities through 2022

Appendix I. List of licensed new investments in thermal electricity-generation units at the end of 2009

Company	Location	Technology/ fuel	MW	Expected commissioning date
PPC SA	Aliveri, Evia Central Greece	CCGT	427	2011
PPC SA	Megalopoli, Peloponnisos	CCGT	800	2012
PPC SA	Florina, Western Macedonia	Lignite	450	2013
PPC SA	Ptolemaida Northern Greece	Lignite	450	2014
Total PPC S.A.			**2127**	
HERON II/ TERNA	Ag. Nektarios, Viotia Central Greece	CCGT	435	2010
ILEKTROPARAGOGI THISVIS (EDISON-ELPE)	Thisvi, Central Greece	CCGT	422	2011
KORINTHOS POWER AE	Peloponnisos	CCGT	396	2011
ENDESA HELLAS AE	Ag. Nikolaos, Viotia Central Greece	CCGT	412	2011
ENELCO SA	Viotia, Central Greece	CCGT	447	2013
BLUE AEGEAN	Korinthos, Peloponnisos	OCGT	150	2010
Total IPPs			**2262**	

Appendix II. List of licensed electricity suppliers at the end of 2009

1. ATEL HELLAS SA
2. ENEL TRADE S.p.A
3. EDF TRADING LIMITED
4. E.ON SALES & TRADING GMBH
5. RWE TRADING GMBH
6. ENTRADE GMBH
7. VERBUND AUSTRIAN POWER TRADING AG
8. EDISON TRADING S.P.A
9. IRON THERMOILEKTRIKI SA
10. NECO S.A.
11. EFT HELLAS S.A
12. HELLENIC PETROLEUM S.A.
13. EGL HELLAS S.A.
14. ENDESA HELLAS A.E.
15. INTERNATIONAL ATHENS AIRPORT SA
16. TERNA ENERGY SA
17. EUROPEAN ENERGY TRADE
18. TEI HELLAS SA
19. VERBUND AUSTRIAN POWER TRADING – ENERGA HELLAS S.A.
20. ITA ENERGY TRADE LTD.
21. ELECTRICITY TRADING COMPANY HELLAS SA
22. EZPADA S.R.O.
23. EHOL HELLAS SA
24. DANSKE COMMODITIES A/S
25. ENER SA
26. VIVID POWER EAD
27. ILEKTRIKI THRAKIS SA
28. IBERDROLA GENERACION S.A.U.
29. ENERGY TRADING LTD
30. BLUE AEGEAN ENERGY SA
31. A2A TRADING SRL
32. CEZ a.s.
33. TRESEN SA
34. POWER SHARE
35. ELECTRABEL ENERGY HELLAS SA
36. ATEL AUSTRIA GMBH
37. ENI SPA
38. ELECTRADE SRL

39. ENALLAKTIKI ENERGEIAKI SA
40. GOLDEN POWER TRADE SA
41. ELPETRA ENERGY SA
42. STATKRAFT MARKETS GMBH
43. DEUTSCHE BANK A.G.
44. HOLDING SLOVENSKE ELECTRARNE D.O.O.
45. GEN-I ATHENS LTD
46. EL EN EMPORIO ILEKTRIKIS ENERGEIAS LTD
47. S.C. TINMAR-IND S.A.
48. OET UNITED ENERGY TRADERS LTD
49. EVN TRADING SOUTH EAST EUROPE EAD
50. ELEWEISS ENERGIA S.P.A.
51. RE TRADING CEE SRO
52. ELPEDISON A.E. EMPORIAS ILEKTRIKIS ENERGEIAS
53. NECO TRADING A.E.
54. GAZPROM MARKETING & TRADING
55. UNIT HELLAS A.E.
56. SUN INNOVATION ANDREAS CHRYSANTHAKOPOULOS LTD

i. List of Acronyms

ATC	Available Transfer Capacity
CAC	Capacity Availability Contract
CAT	Capacity Availability Ticket
CPI	Consumer Price Index
DAES	Day-Ahead Energy Schedule
DEPA	Public Gas Corporation S.A.
DESFA	National Natural Gas System Operator
DSO	Distribution System Operator
EPA	Gas Distribution Company
GDC	Gas Distribution Company
GHG	Greenhouse Gases
HGTSO	Hellenic Gas Transmission System Operator
HTSO	Hellenic Transmission System Operator
HV	High Voltage
IGI	Italy-Greece Interconnector
INGN	Independent Natural Gas Network
IPP	Independent Power Producer
LV	Low Voltage
MV	Medium Voltage
NGS	Natural Gas System
NNGS	National Natural Gas System
NTC	Net Transfer Capacity
PPC	Public Power Corporation, S.A.
PSO	Public Service Obligation
PTR	Physical Transmission Rights
RAE	(Hellenic) Regulatory Authority for Energy
SMP	System Marginal Price
STA	Standard Transportation Agreement for access to the gas transmission system
TSDS	Transmission System Development Study
TDSO	Transmission and Distribution System Operator
TPA	Third-Party Access
TSO	Transmission System Operator
UCTE	Union for the Co-ordination of Transmission of Electricity
UIOLI	Use it or lose it
UIOSI	Use it or sell it

ii. List of Figures

iii. List of Tables