2009 National Report to the European Commission

Regulatory Authority for Energy (RAE)

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REGULATORY AUTHORITY FOR ENERGY
132, Piraeus str., 118 54 Athens, Greece
Tel.: +302103727400, Fax: +302103255460
E-mail : info@rae.gr, Website: www.rae.gr

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1. Foreword

2008 has not been a year of significant changes, but, hopefully, the year when the basis for important structural changes to come were set.

In electricity, we are preparing to enter to the full implementation of the wholesale market, which is currently in the last stage of a transition phase. Modification of the Supply Code to account for tertiary-reserve market and hydro management should be addressed soon. We have to closely monitor smooth operation of the market, and provide participants with all necessary information as well as long-term stability, so that the significant interest in investments (4400 MW of new capacity is either being built or announced for the next few years) is further boosted.

In the retail market, the low and medium voltage tariffs remain regulated. However, we are far along the process of prescribing the methodology for assessing the correct structure and fair level of retail prices according to internationally acceptable regulatory standards. The monopolistic tariff components have already been carefully estimated and the first bills that separately display charges for energy, distribution, transmission and PSO costs will reach final customers in 2009. By doing so, prospective market players will be in the position to better estimate the profit margin for the service they are targeting, while end-customers will have the opportunity to compare suppliers' offers. The important next step, on which we will focus during 2009, is to redesign 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.

Another important aspect is the operation and development of the transmission network. The construction of a 400 kV interconnection between Greece and Turkey was completed in 2008, with synchronous operation estimated to take place in spring of 2010. However, cross-border trading arrangements over the interconnections with our neighbouring countries are not always transparent, nor in accordance to the provisions of EU Regulations. A joint effort should be made in maximizing the available interconnection capacity and improving market conditions. Inside the country, careful planning of the grid expansion is needed so that absorption of renewable energy is not hindered by network congestion. Moreover, 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 may be further exploited; in addition, PSO costs will gradually diminish over the next few years.

It is important to draw attention to the absence of a legally unbundled DSO. The continued performance of DSO duties by an organisational unit integrated within the incumbent, PPC S.A., prevents effective separation of the distribution network activity, in terms of decision making rights and functioning, from the competitive business of the integrated utility. This is a crucial step in ensuring that consumers may freely choose their supplier.

Regarding renewables, wind parks and small hydro units are currently supplying about 3.5% of the energy consumed in Greece, while installed capacity has reached 8% of the total in the interconnected system (12.9% on the non-interconnected islands). Interest in further investment is accelerating significantly, as we believe that the incentives are more than adequate. Our efforts should now concentrate on the realization of the investment plans: of the 10,000 MW of licensed RES investments, only 1,300 MW are in operation, while 34,000 MW are still pending under the licensing procedure. It is, thus, obvious that our priorities should be in:

- simplifying the licensing procedure,

- providing incentives to, as well as educating, local communities, so as to extenuate reactions that often pose unreasonable burdens to project realizations, and
- promoting investments and careful planning in the transmission networks, so that the electricity injected by the RES may be absorbed, or even exported to neighboring markets.

In the natural gas sector, 2008 was definitely characterized by an unprecedented interest from major international investors in transiting gas through Greece. We are closely following the gas market developments in South-East Europe, acknowledging the importance of developing new transit pipelines for the diversification of the country's, and the European Union's in general, natural gas supply sources. The most important proposed projects for transmitting natural gas through Greece are the Italy-Greece Interconnector (IGI), the Trans-Adriatic Pipeline (TAP), and the south branch of the South Stream Pipeline.

The increase of local demand and the interest for the transit projects have emphasized the need to complete missing secondary legislation. The creation of a stable environment with transparent rules and the familiarization of natural gas market players with the regulatory framework which governs the Greek market and the market's conditions are essential for the further opening of the market. All secondary legislation documents (i.e., Network Code, Authorization Regulation and Supply Code) have been put in public consultation within 2008, and their final approval is anticipated in 2009. Thus, the completion of the market's regulatory framework is top priority of both the Greek Government and the Regulator and is reaching completion.

Regulatory Authority for Energy

September 2009

2. Main developments in the gas and electricity markets

2.1. Electricity

2008 was a rather difficult year in terms of high loads, very low water availability and high fuel prices. Due to low hydro production, all conventional fuel plants achieved increased capacity factors and financial returns. Likewise, imports activity was increased, offering some significant spreads to active traders.

In terms of generation capacity, there were no new entrants during 2008, although a 334 MW unit of Aluminium of Greece S.A., now owned by Endesa Hellas S.A., begun commissioning and acceptance trials. Specifically, during the summer time this unit injected significant amounts of power during its commissioning trials, especially during peak-load periods. A quite serious breakdown did not allow the start of the commercial operation of the plant, which is now expected in the fourth quarter of 2009.

Other significant development on the generation side was the contracting of the Unit of HERON Thermoelectriki S.A., a 150MW peaking unit, with the incumbent PPC S.A., as a long-term capacity availability contract, which was more like a tolling agreement between the two companies. Before that, this unit was contracted with the HTSO, to provide ancillary services. The agreement between the two companies was subject to the approval by the Hellenic Competition Commission. In that sense, PPC remains the biggest producer of electricity in Greece, more than 95% of power is generated by PPC and sold in the wholesale market.

No significant developments took place in 2008 as regards rules for cross-border exchanges of electricity, compared to 2007. 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 subject to the fulfillment of UCTE network operation standards by the Turkish system, expected spring 2010.

In the retail market, no significant progress was made, in anticipation of the unbundling of the retail tariffs of PPC, where all charges for energy, networks and PSO, will be presented separately within the existing tariffs, after the ministerial decision of November 2007, according to which PPC is obliged to proceed to the separation of the individual components of its tariffs, and secondly and most important to set out a three year time table of all necessary actions to be taken in order to remove all distortions existing in the current tariffs. Specifically, all cross-subsidies between the categories of consumers and in some cases even between consumers in the same category should be removed, taking care of the gradual and smooth reorganization especially of the domestic tariffs, in order to avoid shocking changes for low income domestic consumers. All necessary regulatory and ministerial decisions required to progress on this issue, were taken, and it is expected that during 2009, the unbundled tariffs will be in use.

According to the above mentioned ministerial decision of 2007, high voltage customers are able to negotiate their tariffs with PPC, in the same manner that they are able to do with other suppliers. The ongoing negotiations have little results till now: all of the high voltage customers remain with PPC and the old regulated tariff, while negotiating the new structure of the tariff. In all cases, PPC remains the main retailer and very little activity has been recorded by other Suppliers in the retail market.

In July 2008, an increase on average of 7% was accepted on PPC tariffs, in order to equal the increased fuel cost. This increase was allocated asymmetrically between the categories of consumers in order to promote the aimed reorganization of the end-user tariffs.

No progress was achieved in 2008 as regards legal unbundling of the DSO. The relevant provisions of Law 3426/2006 have not been enforced. It is reminded that according to these provisions, the respective organisational unit of PPC S.A. had to be transferred to the Hellenic Transmission System Operator (HTSO) by 1.7.2007, who would assume the role of a combined Transmission and Distribution System Operator (TDSO). The duties of the DSO were performed in 2008 by the aforementioned organisational unit of PPC S.A. More details are presented in Section 3.1.3.

2.2. Natural Gas

Year 2008 was definitely characterized by an ever-increasing interest from third-parties in transiting gas through Greece. Both RAE and the gas TSO (DESFA SA) received applications for the construction of independent transit pipelines in Greek territory and the reservation of capacity in the entry points of the Greek natural gas system, respectively. Furthermore, discussions at governmental, regulatory and technical level for a new interconnection between Greece and Bulgaria had been well underway in the end of the year.

In the domestic front, demand was sustained to 2007 levels, mainly due to the unexpected outage of two gas-fired power plants in the last quarter of the year, relatively mild weather and the consequences of the financial crisis starting to being felt in the Greek economy. The supply situation has also remained unchanged, both in terms of market shares and gas supply sources, with the incumbent DEPA S.A. being the sole supplier in the country. Notably, however, new players expressed their interest for the exercise of gas supply activities in Greece, by submitting applications for licenses.

In 2008, eligibility rights were extended to all large consumers in the country, as well as to the non-domestic consumers located outside the concession areas of the three distribution companies operating under a monopoly regime, in accordance with article 28.8 of Directive 2003/55/EC (The “Gas Directive”).

The regulator continued the effort of completing the regulatory framework both for transit and domestic gas flows. In summary, major developments from the regulatory perspective were:

- The completion of the balancing regime, following the approval by the regulator of all cost items and charges concerned in.
- The completion of a draft Authorization Regulation, that sets the entry rules for both gas supply and development of independent infrastructure in the country. The Regulation was put in public consultation in September 2008 and is currently in the process of formal approval.
- The completion of a draft Network Code put under public consultation in October 2008 and expected to be formally approved within 2009.
- Joint approval by the Greek and Italian authorities of the rules of the open season procedure to be carried out by the sponsors of the undersea part of the Italy-Greece Interconnector, i.e. the IGI-Poseidon Pipeline.

- Beginning of the approval process of the accounting unbundling rules submitted by all gas undertakings in Greece, estimated to be put into force in 2009.

Last but not least, at the end of the year, RAE published an extensive report on the security of gas supply in Greece, providing a thorough analysis of the characteristics of the Greek situation regarding long/short-term demand forecast and patterns, supply diversification issues and infrastructure development requirements and establishing a work plan for next year with the TSO, DESFA SA.

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). More information is given in Appendix I.

Cross-border congestion

During 2008 Greece was electrically interconnected with its 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. Under normal transmission system availability conditions in the Balkans area, the congestion appearing on the northern interconnections is associated with transmission constraints outside the Greek system (Serbia-FYROM, north interconnections of Albania, FYROM-Bulgaria). Congestion on the Greece-Italy interconnection is associated exclusively with the capacity of the link itself.

Rules for congestion management on Interconnections

The main principles of interconnection congestion management rules in 2008 were the following:

- Annual, Monthly and Day-ahead (D-1) Explicit Auctions of Physical Transmission Rights
- UIOSI rule applied to long-term rights (reallocation by HTSO at Monthly and Day-Ahead Auctions) and UIOLI at the time of firm nomination
- Long-term PTRs freely transferable between participants, subject to TSO approval of transferee eligibility.
- Allocated long-term rights subject to cancellation by TSO 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.
- PTRs allocated at day-ahead auction are firm.

Main improvements compared to 2007 rules for congestion management on interconnections are the performance of day-ahead auctions at D-1 instead of D-2 and the simplification of the financial guarantee requirements.

Under this scheme, 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	100	100
Albania	100	100
Italy	0	100

Table 1. HTSO responsibility for capacity allocation on interconnections

Congestion on the Greece - Italy interconnection for the direction of imports to Greece from Italy 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 2008

In the import direction, HTSO organised one annual and 12 monthly auctions. 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 forecast energy balance and ATC for imports was allocated mainly through monthly auctions. Only a small number of day-ahead auctions were organised for imports (104 auctions in total for all northern interconnections), since short-term calculation of NTC on the northern borders of Greece is not yet established as standard practice among involved TSOs.

In the export direction, HTSO organised one annual and 201 daily auctions. Monthly auctions were not organised due to concerns about the medium-term security of supply in the Greek system. These concerns arose from special circumstances (critically low hydro reserves, uncertain availability of energy for imports) that prevailed throughout 2008.

RAE accepted HTSO proposals to limit interconnection capacity made available long-term in 2008, 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. Similar proposals by HTSO, to limit interconnection capacity made available long-term for 2009, have been also accepted by RAE in December 2008.

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.

HTSO annual auction in import direction (Number of bids: 8, Number of successful bids: 5)

Period	Border	Auctioned capacity (MW)	Product Definition	Auction Price	
				€/MWh	€/MW
JAN - DEC	**BG**	**50**	All year excl. maintenance (8520 hours)	2.59	22066.8

Table 2. Annual auction results in import direction

HTSO annual auction in export direction (Number of bids: 18, Number of successful bids: 8)

Period	Border	Auctioned Capacity (MW)	Product Definition	Allocated Capacity (MW)	Auction Price	
					€/MWh	€/MW
JAN - MAY & SEP - DEC	**IT**	**250**	LOW LOAD (22:00 - 06:00 CET) & SUNDAY (2800 hours)	**245**	0.77	2156
	BG			**5**		
	FYROM			**0**		
	AL			**0**		

Table 3. Annual auction results in export direction

HTSO monthly auction results in import direction

		Allocated Capacity & Auction Price											
		JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**
BG	MW	100	150	150	150	200	250	275	275	125	125	150	125
	€/MWh	2.55	1.57	5.52	9.14	14.6	16.0	19.5	19.5	35.78	20.58	18.56	22.68
FYROM	MW		40	100	100	40						80	50
	€/MWh		0.57	1.55	3.72	10.78						0.50	15.16

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				100					40	75		
	€/MWh				0.15					21.30	32.10		

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

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

There has been no significant improvement in provisions for information to market participants in the context of congestion management, compared to 2007.

Integration of congestion management in wholesale market functioning

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

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

PPC SA is by Law the exclusive owner of the electricity Transmission System, the interconnections as well as any future System expansion. The operation of the Transmission System is assigned to an Independent Transmission System Operator, namely “Hellenic Transmission System Operator S.A.” - HTSO S.A. (51% Greek State, 49% PPC S.A.). According to the provisions of Law 3426/2005, which amended the basic electricity Law 2773/1999, PPC SA, as the exclusive owner of the transmission system, is responsible for the development of the transmission system, following the relevant 5-year plan produced by the HTSO and approved by the Minister of Development following RAE’s opinion. Moreover, according to the provisions of the abovementioned Law, PPC is responsible for planning and carrying-out the maintenance, daily operation and actual functionality of the transmission system, while the HTSO is responsible for developing the relevant switching program. PPC and HTSO have to conclude contracts on these issues.

PPC SA is also the exclusive owner of the electricity distribution network. According to the provisions of Law 3426/2005, until June 30th 2007, a special department of PPC assumes responsibilities of the Distribution System Operator. The Law stipulates that, by July 1st 2007, these responsibilities are transferred to the HTSO (along with the special department of PPC), who will be both Transmission and Distribution System Operator. This transfer has not yet taken place.

The Distribution System Operator (DSO), according to the provisions of the same Law, is responsible for ensuring the reliability, functionality and efficiency of the distribution network, as well as for third party access to the distribution network. The Distribution System Operator is responsible for the distribution network that is interconnected with the mainland transmission system.

The owner and actual operator of the distribution network, i.e. PPC for the distribution network of the entire country, is responsible for receiving connection applications, maintaining the functionality and efficiency of the network, as well as developing and maintaining the network according to the relevant program developed also by the DSO. PPC and the Distribution System Operator have to conclude contracts with reference to the development and maintenance of the distribution network of the mainland and the interconnected islands.

For the non-interconnected islands, the operator of the relevant network (a different department of PPC S.A., called “*Islands Network Operations Department*”) is also the generation dispatcher.

Network Tariffs

In 2008, there were no changes in the electricity network tariffs both for transmission and distribution. The tariffs approved in 2007 continued to apply throughout 2008. Please refer to the 2008 Greek National Report for more details.

Concerning the use of congestion revenues, no use of them was made during 2008 in view of utilizing a significant part of such revenues during 2009 for financing the Greece – Turkey 400kV interconnection[1]. The income of HTSO resulting from congestion management during 2008 was, according to HTSO, 30,978,021 Euro (23,233,516 Euro after tax 25%). Total income (i.e. years 2003-2008) amounted to 53,637,183.52 Euro (after tax).

Network Performance and Quality of Service

In 2008, 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 expected to be applied within 2009 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 yet been set for the Distribution System Operator; therefore, the DSO does not currently report any quality of service indicators. Arrangements as per the above are to be developed under the umbrella of the Distribution Network Code.

The proposal of RAE for the *Distribution Network Code*, 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 (these are established by 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). In 2008, the Regulator initiated work to review PPC internal rules and data on QoS dimensions monitored to date by PPC. The work is ongoing and will allow the Regulator to report on the overall service quality level based on available historical data, to formulate and publish its opinion on these as well as on current PPC practices regarding service quality monitoring and reporting and necessary improvements thereof.

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 tariffs. Connection conditions and charges have not been approved by the Minister for Development.

[1] This has actually been implemented in 2009, since 54.5 million Euros were allocated for the construction of the interconnector Greece-Turkey.

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 2008. DUoS tariffs are published by the Regulator.

Balancing

The electricity market arrangements in Greece do not include a real-time balancing market. The whole balancing mechanism is based on the ex-post, administrative settlement of imbalances among the market participants, since it is considered that the current stage of development of the electricity market, especially regarding the competition on the supply side, does not allow for the establishment of a properly functioning, efficient balancing market. This concept may be reconsidered in the future, should the market evolution and conditions permit.

3.1.3. **Effective unbundling**

Transmission

The unbundling regime of HTSO remained unchanged during 2008. Please refer to last year´s National Report for details

Distribution

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

Through the process of developing the *Distribution Network Operation Code* and the public consultation held in July 2008, it became evident that substantial inefficiencies and practical issues arise from the allocation of duties and responsibilities that are complementary and/or interrelated to two separate entities (Network Operator and Network Assets Owner), as it is foreseen by Law 3426/2005. These include the following:

a) Dilution of responsibility between Network Operator and Network Owner, giving rise to a need for additional contractual arrangements between them.

b) Additional processes are necessary in order for the Network Operator to monitor and control the activity of the Network Owner. This leads to a relocation of significant human resources from the Network Owner to the Network Operator in order for the latter to be able to perform its duties, to an increase in workload for both entities and to efficiency losses.

c) Failure to provide convergent incentives to the Network Operator and to the Network Owner in the context of an incentive-based regulation scheme.

d) Retention of the core distribution tasks by a division inside the integrated utility (Network Owner) does not promote the development of an independent culture of the network business.

These are considered to pose significant impediments to the effective regulation of the distribution business. For this reason, RAE advocates for a legislative revision to mandate the organisation of the entire distribution business (operation and ownership of assets) under a single entity, which shall enable essential fulfilment of unbundling requirements for the DSO. It is likely that this entity would be established as wholly-owned subsidiary of PPC S.A.

3.2. Competition Issues

3.2.1. Description of the wholesale market

In 2005 a pure mandatory pool model was adopted for the Greek wholesale electricity market, according to Law no. 3426/ 2005 and the 2005 Grid and Market Operation Code. The wholesale market consists of:

(a) The Day Ahead market (pool), where the scheduling and clearing of both the total energy produced and consumed in Greece, including imports and exports, as well as the procurement of ancillary services takes place ('mandatory' pool).

(b) The Real Time Dispatch operation.

(c) The Imbalances Settlement, which includes the settlement of energy deviations from the Day Ahead program and the settlement of the ancillary services required for the balancing of the system.

(d) The Capacity Adequacy Mechanism, through which part of the fixed costs of the production capacity are covered[2].

All transactions are made via the Day Ahead market, which does not include bilateral transactions with physical delivery and respective contracts between producers, suppliers and customers. However, bilateral financial contracts may be freely concluded outside the pool. Through the daily market, the generators receive the System Marginal Price (SMP) which effectively covers at least their fuel cost and they have to recover the rest of their capital cost through their participation in the Capacity Assurance Mechanism. A cap price for SMP of 150 €/MWh is in place. More details for the wholesale market design are offered in Appendix I.

The 2005 *Grid and Market Operation Code* describes the gradual transition to the full new market operation in five steps within two years. Although more than 3 years have gone by, the fifth step (called the "Fifth Reference Day") has not been achieved yet and has been scheduled for May 1st 2009[3]. This delay may partly be attributed to the lack of sufficient resources on the side of the HTSO. Thus, for 2008 and until the Fifth Reference Day, the Day Ahead market serves only for the provision of an indicative unit commitment schedule and a reference spot price (SMP), with the settlement conducted ex-post according to the energy actually produced and consumed (following the real time dispatch orders of the HTSO). On January 1st 2009 the Day Ahead market will also offer an indicative schedule for the procurement of ancillary services (primary and secondary reserve). The Imbalances Settlement will be activated on the Fifth Reference Day.

Year 2008 can be described as a quite volatile year, concerning the prices in the wholesale market, and was marked by high oil and natural gas prices, while the hydro–production suffered by a third in-a-row dry year. It was, consequently, well expected the average System Marginal Price (SMP) to scale up to the range of 80-90 €/MWh. The following plots present the daily variation of the SMP during 2008.

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[2] The Capacity Adequacy Mechanism is described in detail in Chapter 5.1.

[3] In March 2009 this date was moved to January 1st, 2010, as the TSO informed RAE that the required software infrastructure wasn't in place yet to support the full operation of the wholesale market.

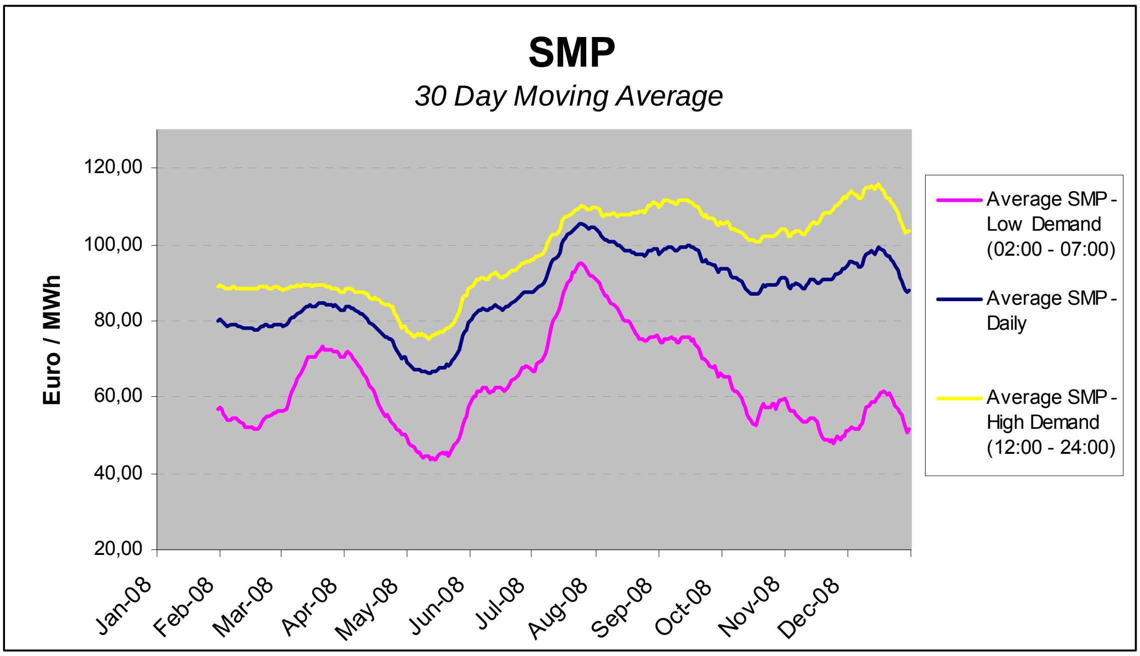

Figure 1. SMP – wholesale electricity market (30-day moving average)

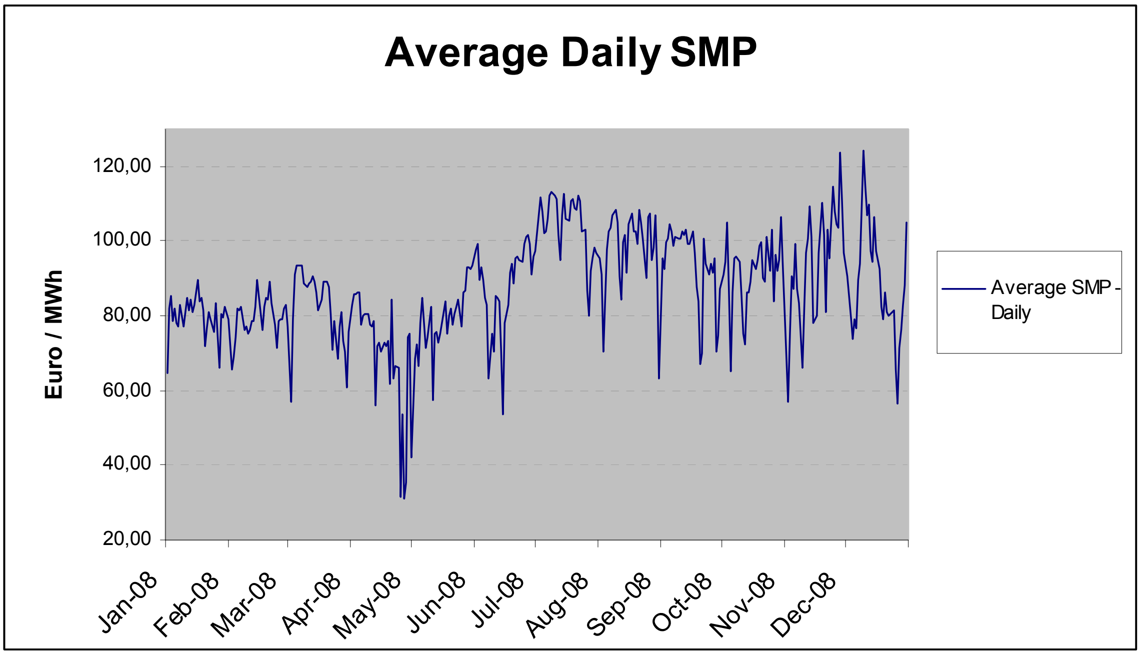

Figure 2. Average Daily SMP – wholesale electricity market

As far as the market structure is concerned, the national integrated electricity company, PPC, owns about 95.3% of the installed capacity of 'dispatchable' units (lignite, natural gas, oil and large-hydro). Two competitors hold the remaining 4.7% with two natural gas fired units (390MW CCGT and 150 MW open cycle GT), although a new unit (334MW CCGT) is expected to begin its commercial operation in 2009. If the RES and small co-generation, not owned by PPC, are taken into account, then its market share in terms of installed capacity falls to around 90%.

Year	Total installed capacity - 'dispatchable' units (MW)	PPC market share
2004	10797.3	98.6%
2005	10797.3	98.6%
2006	11577.6	95.3%
2007	11572.6	95.3%
2008	11572.6	95.3%

Table 6. Total installed capacity and dominant utility's market share.

Company	Capacity (MW)	Year of Commissioning	Unit Type
T-Power S.A.	384.5	2005	CCGT (single shaft)
IRON S.A.	147.8	2004	Gas Turbine
Endesa Hellas S.A.	334.0	2008	CHP

Table 7. Thermal generating capacity owned by IPP's.

Fuel	Owner	Installed Capacity (MW)	Capacity Factor (%)
Lignite	PPC S.A.	4808.1	69.39
HFO	PPC S.A.	718.0	54.69
CCGT	PPC S.A.	1577.6	66.20
	T-Power S.A.	384.5	55.05
	Total	**1962.1**	**63.97**
OCGT	PPC S.A.	339.0	56.39
	IRON S.A.	147.8	23.17
	Total	**486.8**	**45.31**
Large-scale CHP	Endesa Hellas S.A.	334.0	N/A*
Hydro	PPC S.A.	3016.5	N/A

* A serious breakdown did not allow the start of its commercial operation.

Table 8. Installed capacity by fuel and ownership. Capacity factors by fuel type.

From the above, it is concluded that the proportion of installed capacity owned and the net generation volume produced by the largest three companies is equal to 100% (always referring to the companies participating in the market, thus excluding RES and small cogeneration). Due to the aforementioned market share of PPC S.A., in terms of generating capacity and volume in the mainland (interconnected) system, the HHI index is estimated close to the upper bound of 10,000. On the positive side, there has been increased interest for new plant investments in the recent years, both from PPC and from private companies. The table in Appendix II shows the expected commissioning date of new plants.

On the supply side of the market, only PPC participates as a load representative in the wholesale market, although a number of companies are active as importers/exporters. Apart from that there is no formal demand side participation in the wholesale market in Greece. Demand's involvement to the market is minimal and may only be affected indirectly, through the minimization of the use of electricity by a limited number of industrial customers during peak hours, when the price of electricity is high. Nevertheless, although these measures do reveal some elasticity of the consumers to the high prices during peak hours, in general they are considered as adequacy-of-supply measures.

Integration with neighbouring member-states

The relevant electricity market for Greece is, to a significant part, the national market. The total interconnection capacity with neighbouring member states (namely Italy and Bulgaria) is in the order of 1300 MW; this represents about 13 % of the year's peak demand (about 10000 MW).[4]

A number of traders, apart from PPC, are active in the region and trading activity, mainly in form of imports to Greece, amounted to about 6400 GWh (about 11% of total yearly demand of Greece).

Trading arrangements over the interconnections were not sufficient to promote further trading activity during 2008, for two main reasons: (a) the Auction Rules for determining ATC on interconnections concerning exports from Greece pose a constraint related to security of supply in Greece, and (b) the swing of SMP differentiation between Italy and Greece concerning peak and off-peak SMPs which at some point created unpredictable trading conditions (see Table 9 for a comparison of average prices, as reported by HTSO and the Italian TSO, TERNA).

	Average SMP during peak hours (€/MWh)	**Average SMP during off-peak hours (€/MWh)**
HTSO	98.97	71.54
TERNA	105.63	61.99

Table 9. Comparison of SMP prices in Greece and Italy during peak and off-peak hours.

It must be emphasized that integration with neighbouring countries is, to a significant extent, prohibited by the lack of appropriate implementation of Regulation 1228/2003 in the countries of the Balkan region, especially regarding capacity allocation mechanisms and transparency issues. This is a significant obstacle to trade and requires a coordinated approach at the level of both the EU and the Energy Community.

[4] Total interconnection capacity of Greece is in the order of 1500 MW, if the interconnections to FYROM and Albania are taken into account.

3.2.2. **Description of the retail market**

Table 10 and 9 present the consumption of final customers in 2008 broken down by sector and connection voltage, for the interconnected system and the non-interconnected islands respectively. The retail market is national, although there is a differentiation for the non-interconnected islands due to the different conditions in the generation activity (i.e. some islands consist of a single generating plant or a small number of plants, therefore not allowing for competition in the wholesale market). Retail competition is not yet feasible in practice on the non-interconnected islands.

Total consumption at the transmission system level (for the interconnected system only) was 56.4 TWh, 99.98% of which was supplied by PPC, with a very small amount being supplied by three other suppliers (with ATEL HELLAS A.E. supplying the largest amount, approx. 8.5GWh, Aluminium of Greece supplying 3.3GWh as an autoproducer and Heron supplying 0.5GWh).

Interconnected System (GWh)								
Voltage	Residential	Industrial	Commercial	Agricultural	Public	Traction	Mines, Pumping	**Total**
LV	16369.6	1271.3	10258.8	2437.7	1.581.3			**31918.7**
MV		5675.6	4313.0	418.0	910.0	152.7		**11469.3**
HV		7553.4					2157.6	**9711.0**
Total	**16369.6**	**14500.3**	**14571.8**	**2885.8**	**2491.3**	**152.7**	**2157.6**	**53099.0**

Table 10. Electricity consumption for the interconnected system (Source: PPC; data refer to metered consumption at customer site)

Non-interconnected islands (GWh)								
Voltage	Residential	Industrial	Commercial	Agricultural	Public	Traction	Mines, Pumping	**Total**
LV	1755.9	123.3	1717.8	215.9	284.2			**4097.1**
MV		204.5	600.0	33.5	185.1			**1023.1**
Total	**1755.9**	**327.9**	**2317.8**	**249.3**	**469.3**			**5120.2**

Table 11. Electricity consumption in the non-interconnected islands (Source: PPC; data refer to metered consumption at customer site)

At the end of 2008, apart from PPC SA, supply licenses have been granted to 37 other companies (see list in Appendix III). 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.

Supply activities follow the *Supply Code*, which was issued in 2001. The supplier switching process contained in this Code is unfavourable for consumers and is considered obsolete (it was introduced in 2001 and has not been modified since) as it introduces an obligation to notify the current supplier of a unilateral resolution of the supply contract 3 months prior to the switch. In practice, however, the incumbent supplier has so far been flexible about this requirement. The *Supply Code* is under revision, expected to be completed by the end of 2009. It is envisaged that the new Supply Code will include the following:

- suppliers and customer obligations and rights
- procedures for submitting an offer to supply
- procedures for switching suppliers
- quality of supply services and indicators
- data publishing obligations
- regulation of supply by companies with significant market share
- dispute resolution

Switching procedures as far as the interaction of the Supplier with the HTSO and the DSO are concerned, 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 the "Handbook 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 need to 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.

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.

Despite the procedures being in place for supplier switching, there has been minimal competition in the retail market due to the following factors:

- Regulated retail tariffs have not been cost reflective and contain cross-subsidies between the different tariff groups.
- Due to the market dominance of PPC, there is lack of information on consumer characteristics, including typical load profiles.
- Consumers are still not fully aware of their freedom of choice of supplier.
- End-user retail tariffs have been bundled, i.e. are not separated by activity.
- There is no independent Distribution System Operator and no Distribution Code (although there is a draft version which went through public consultation in 2008).
- The revision of the Supply Code which will introduce more favorable switching conditions for consumers.
- Details of the regulations governing the Supplier of Last Resort have not yet been determined.

Retail price developments

Retail electricity prices for MV and LV customers remain regulated. In November 2007, PPC requested significant increases to the existing tariffs. These price adjustments were requested on the basis of the increases in fuel prices, which in 2007 accounted for 62% of total operating costs. RAE examined this request in an opinion (RAE Opinion 545/2007) to the Ministry of Development. RAE noted that PPC fuel costs increased by 87% between 2004-2007, while the share of fuel costs in total operating cost has also increased. During the same period, inflation was 8.92% and the cumulative increase of tariffs was 15%. As a result, RAE concluded in favour of a gradual nominal increase of PPC's allowed revenue and proposed to implement those price adjustments over a three-year regulatory period. As a result, retail tariffs for consumers connected to the MV and LV networks increased by 7% on average in December 2007 and July 2008 respectively.

Regarding the increases that took place in July 2008 by consumer category:

- Medium voltage (MV) commercial and public increased by 8%
- MV industrial increased by 9.5%
- Domestic tariffs increased by 6.5% on average (the level of increase varied for the different domestic consumer categories which are defined by the metered consumption in a 4-month period)
- LV industrial tariffs increased by 7-10%
- LV general use tariffs increased by 5.8-7%
- All other MV and LV tariffs increased by 7%

Following an opinion by RAE, the Minister of Development also introduced a Social Tariff for low-income households with low levels of consumption (below 800kWh per 4-month period). The details for the application of this tariff are yet to be determined, although RAE produced a relevant opinion document in December 2008 describing the details for its introduction.

Voltage	Year	Domestic	Industrial	Commercial	Agricultural	Public Lighting	Public	Traction	**Total**
LV	2007	92.5	103.3	122.7	38.0	67.9	114.0		**98.4**
	2008	101.1	117.4	133.8	46.0	94.5	126.3		**109.1**
MV	2007		68.1	86.9	32.3		82.0	92.0	**75.0**
	2008		78.4	93.2	39.6		97.3	102.8	**84.8**
HV	2007		49.8						**49.8**
	2008		58.1						**58.1**
Total	**2007**	**92.5**	**62.1**	**113.1**	**37.2**	**67.9**	**96.3**	**92.0**	**86.4**
	2008	**101.1**	**71.8**	**122.0**	**45.1**	**94.5**	**111.1**	**102.8**	**96.8**

Source: PPC, excluding taxes

Table 12. Average retail electricity prices by consumer category, €/MWh, 2007-2008

PPC was expected to submit within 2008 regulated tariff structures for each consumer category to achieve:

- unbundling of the various services (generation, transmission, distribution, supply)
- cost reflectivity and removal of cross-subsidization 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.

This process is expected to be concluded within 2009.

Consumers

A total number of 308 documents on complaints/inquiries[5] concerning electricity and gas were registered to RAE, either directly by individual consumers or through other responsible consumer bodies/organizations. Although RAE does not have a legal mandate to act as a dispute settlement body, per case, between service providers and consumers, it investigates any submitted complaint and responds to all inquires.

Complaints 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 the Distribution Code and the limitations of the Supply Code in force, usually a certain 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
- put a financial fine to the service provider for non compliance with regulations or with the above mentioned order.

The majority of complaints does not find a solution and consumers often have to appeal to a court.

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

Despite the absence of a formal definition, RAE treats/recognises 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.

In the absence of statistical data on complaints/inquires classification, only a rough estimate of the complaint/inquiry nature may be given. The more frequent subject of cases on electricity registered to RAE was concerned with:

[5] Please note that the number refers to submitted documents, not individual cases. As a rough estimation, 60% of the documents referred to electricity complaints/inquiries and 40% to gas.

- Outages and voltage quality followed by damage to houseware property
- Irregular meter readings
- Unjustifiably-high electricity consumption and amount of bills
- Electricity price increases

Measures to avoid abuses of dominance

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 significant 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 in the market forced the incumbent to participate in the market and avoid exclusionary practices. Moreover, by considering in the algorithm the technical constraints of the units, which were called upon in the past by the incumbent in order to affect the operation of the market, the market clearing 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 look like, in order to be efficient. This will also minimize 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 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 operations' 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 (due to irrigation, spilling and water supply) to be injected in the market. Moreover, on a monthly basis, owners of hydro units have to submit a report regarding the forecasted management of hydro for the twelve months.

- 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 dominance or market price manipulation, a regulated price cap is set for the offers. Its value is decided by the Minister of Development, following an opinion by RAE.

- Price Floors

  In order to avoid abuse of dominance or market price manipulation, a regulated price floor is set for the offers 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 of the aforementioned rules falls mainly under the market operator (HTSO) responsibilities. RAE has the more general responsibility of monitoring the developments of the electricity market and the overall market behaviour of all 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 the 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

There are two interconnections of the Greek transmission system with neighbouring gas systems, one with Bulgaria in the northern border of the country and one with Turkey in the east border. There is actually 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.

There is no physical or contractual congestion experienced in both interconnectors, since the technical import capacity is much larger than the contracted capacity and the current levels of demand in the country. This is demonstrated in the Table below:

Entry Point	Technical Capacity	Peak Used Capacity 2008	Average Used Capacity 2008
Bulgaria	15.8×10^6 Nm^3/day	11.3×10^6 Nm^3/day	7.3×10^6 Nm^3/day
Turkey	20.5×10^6 Nm^3/day	2.5×10^6 Nm^3/day	1.3×10^6 Nm^3/day

Table 13. Technical capacity and capacity used on natural gas interconnectors.

Nevertheless, congestion, either physical or contractual may arise in the upstream systems due to the reasons presented below.

There was no gas transit through Greece during 2008.

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

<u>Network Tariffs</u>

A. TPA tariffs

Tariffs for TPA to the National Natural Gas System (Transmission System and LNG Terminal) as well as connection charges, were set in 2006, by means of the Ministerial Decision 4955/2006. Regarding the transmission system tariffs, they refer to the reservation and use of pipeline capacity and are independent of the entry and exit points used or the distance of transportation (postage stamp). Regarding the LNG tariffs, they refer to the reservation and use of regasification capacity and – implicitly - to the respective LNG reception services and temporary storage. There is no tariff for long-term storage services as yet. For a detailed analysis of the tariff derivation methodology and the approval procedure, please refer to the relevant section of National Report 2008.

There have been no developments or structural changes regarding tariffs for TPA to the National Natural Gas System compared to the year 2007. Tariffs were simply adjusted for inflation compared to the previous year. Thus, the actual TPA tariffs for 2008 are presented in the table below:

Tariff	Capacity Charge (€/peak day MWh/year)	Commodity Charge (€/MWh/year)
Transmission Tariffs 2008	541.121	0.266224
LNG Tariffs 2008	22.703	0.017130

Table 14. TPA tariff coefficients

DESFA SA 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 Greek and English.

B. Distribution tariffs

Three distribution companies are currently active in Greece (hereinafter "EPAs"), operating under a monopolistic concession regime, in accordance with article 28.8 of the Gas Directive and Article 21 of the Law 3428/2005 (Government Gazette A' 313, 27.12.2005 - Gas Law). EPAs perform the combined activities of DSO and exclusive supplier. Therefore, EPA tariffs are bundled in the sense that there is no discreet charge for transmission and distribution of gas, but a single end-user tariff including all gas and non-gas costs and profit of the company. EPAs set their tariffs under a revenue cap scheme, as set out in their respective concession license, which is adjusted every year according to CPI. Only rights of ex-post control of compliance with the cap are assigned to the regulator. EPAs have the right to (and actually do) follow the methodology of their choice in setting the end-user prices (market value or cost plus), subject to previous notification to the regulator. EPAs are obliged to publish the actual end-user tariff.

According to article 24 of the Gas Law, access is granted to other suppliers serving eligible customers in the distribution system of each EPA (for an analysis of eligibility rights in Greece, please refer to the respective section). The tariffs for accessing the distribution system are approved by the regulator (article 31 of the Gas Law) in full compliance with the provisions of the Directive. TPA tariffs are expected to be set by 2009, following the completion of accounting unbundling of the EPAs (see relevant section). In the interim period, the tariffs for access to the distribution system have been fixed according to the provisions of article 31.4 of the Gas Law.

Balancing

Background

According to the Gas Law, DESFA S.A. is responsible for balancing deliveries and off-takes in the natural gas transmission system and providing balancing services to the users. The detailed balancing scheme is included in the Standard Transmission Agreement (STA). In summary, positive and negative imbalances of independent shippers are aggregated, while the TSO performs balancing actions (injection or withdrawal of gas) only when physical imbalance in the system occurs. Shippers have the right to trade imbalances. Shippers' Imbalances are priced according to a Daily Balancing

Gas Price, which depends on the average cost of the balancing gas provided by the TSO, while penalties exist for imbalances outside certain tolerance levels.

According to the balancing scheme, every year DESFA SA prepares and submits to RAE for approval a balancing plan. The balancing plan includes the estimates of the TSO regarding balancing gas needs and an evaluation of possible balancing gas supply sources for the following year. Following the approval of the balancing plan, DESFA SA can enter into balancing gas supply contracts with suppliers, following a tender procedure.

All costs arising from providing balancing services are recovered from the TSO through relevant charges paid from the users, so that the TSO is cash neutral. RAE is responsible for approving the balancing costs and the methodology for allocating that cost to the users of the transmission system.

Developments

In 2008, the balancing regime described above was applied for the first time. Specifically:

1. The annual balancing plan of DESFA SA for the year 2008 was approved by RAE in June 2007. 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.
2. RAE approved the balancing cost allocation scheme and the relevant shipper's charges for which 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 derivation, 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 have been presented in detail in the National Report 2008. Separate sections provide developments for legal, functional and accounting unbundling.

Legal unbundling

To summarize the current status regarding legal unbundling:

- Following the entry into force of the Gas Law in December 2005 that transposed to the Greek legal system the Gas Directive, the TSO of the National Natural Gas System (NNGS) was established as a "société anonyme" under the name of "DESFA S.A." in February 2007. The new company is a 100% subsidiary of DEPA SA, the incumbent and vertically-integrated gas company in Greece. DESFA SA is the owner and operator of the NNGS which is comprised of the main high-pressure pipeline and its branches and the LNG Terminal at Revithoussa island. DESFA SA has exclusive rights for operation, maintenance, development and exploitation of the NNGS and is currently the only gas system operator in the country.

- Three distribution companies are currently active in Greece (the EPAs), operating under a monopolistic concession regime, in accordance with article 28.8 of Gas Directive and article 21 of the Gas Law. All EPAs have the legal form of a "société anonym", having as shareholders the incumbent DEPA SA by 51% and private investors by 49%. 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 the aforementioned article of the Gas Directive.

Except from DEPA SA, DESFA SA and the three EPAs, no other company operates in the Greek gas market as of today. For the three new distribution concessions that are planned, Commission decision E(2008)4773 allows for a derogation from legal unbundling requirements and provides only for the obligation for accounting unbundling. Therefore, there are no outstanding issues regarding legal unbundling.

Functional unbundling

DESFA SA and future infrastructure operators

Regarding functional unbundling of DESFA SA from DEPA SA, the principal provision of the Gas Law lies in article 7, according to which although DESFA SA is 100% subsidiary of DEPA SA, for the first ten years from its establishment, the president and the members of the board of directors as well as the managing director of DESFA SA are appointed by means of a joint decision of Minister of Development and the Minister of Economy and Financing.

Furthermore, Gas Law provides that detailed rules for functional unbundling, including the obligation of DESFA SA to adopt and enforce a Compliance Code which shall specify relevant obligations of its staff and management as to avoid any discriminatory in favour of the mother company, will be elaborated as terms of the Authorization for Ownership and Operation of the National Natural Gas System that will be granted to DESFA SA according to the procedure specified in the Authorization Regulation.

The said Authorization Regulation sets out the procedures for granting, amending and revoking of all licences provided for in the Gas Law such as supply, ownership and operation of independent infrastructure etc, as well as the terms and conditions for market participants to exercise the respective activity. In July 2008, RAE put on public consultation a draft of the said Regulation. A large number of market players participated to the consultation, which was concluded in October 2008. It is expected that the Authorisation Regulation will be adopted within 2009.

The draft Authorisation regulation includes detailed provisions regarding the unbundling of DESFA SA, as well as monitoring procedures, in line with the requirements of the Gas Directive. Similar provisions and obligations are foreseen for a all independent infrastructure operators that may exist in Greece, and have been included in the terms of the respective authorisations. It should also be noted that the Gas Law provides for the application of the "100.000 customers" rule in all cases of future DSOs in the country.

Therefore, RAE expects that with the adoption of the Authorisation Regulation, the complete set of rules for functional unbundling will be in place within 2009.

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. DEPA S.A. is expected to submit the said rules in 2009. Therefore, unbundled accounts are expected to be published for the financial year 2009.

4.2. Competition Issues

As was also explained in the National Report 2008, pursuant to Article 28.3 of the Gas Directive and due to the ten-year derogation period granted to Greece in November 1996, the full opening of the market has to be realized at the latest within three years after the expiry of the derogation period (i.e. November 2009), subject to the milestones set therein. In addition, existing distribution concessions in Greece have been exempted from the provisions of the Gas Directive regarding eligibility rights of their customers for the whole duration of the concession (Article 28.8 of the Gas Directive).

Therefore, according to the provisions of the Gas Law eligible customers are:

a. Power generators, irrespectively of their annual consumption of natural gas.

b. Heat and power co-generators with an annual consumption of natural gas exceeding 9 Mm^3/year.

Moreover, as of 15.11.2008:

c. Non-household customers located outside the geographic areas served by regional gas distribution companies under a concession regime (EPAs), irrespective of their annual consumption.

d. Non-household customers located in the EPA areas, purchasing natural gas for final use in vehicle motors in the form of Compressed Natural Gas.

e. Large customers, i.e. customers with an annual consumption of over 9 Mm^3/year, located in the EPA areas.

f. The existing EPAs of Attica, Thessaly and Thessaloniki, for natural gas quantities exceeding the annual contract quantity specified for year 2010 in their respective contract with DEPA SA, and up to the expiry of each contract (2016). After the expiry of these contracts, existing EPAs will have the right to choose their supplier for the whole of the natural gas quantities they purchase.

End-user eligible customers (i.e. excluding EPAs) represented at the end of 2008 nearly 90% of total gas demand in Greece.

DEPA S.A. remained the only gas importer in the country and the sole gas supplier to all eligible customers and the EPAs.

4.2.1. Description of the wholesale market

In 2008, DEPA SA remained the only importer of gas in the country and the sole supplier of gas in the country market.

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

Given the situation regarding interconnections as described in section 4.1.1, LNG facility at Revithoussa island, remains the most prominent point for the entrance of new suppliers in the Greek gas market.

For the time being, there are no storage facilities in the Greek natural gas system. The LNG storage tanks are used only as short-term storage for the operation of the station.

4.2.2. Retail market: Consumer complaints/inquiries

As described above, there are four end-users supplier, DEPA S.A. and the three EPAs. DEPA S.A. 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 2008 were substantially higher than those in 2007, following the unusually high prices of oil products in the same period. Some indicative annual average prices are presented below, for EPA Attica and EPA Thessaloniki:

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

* energy prices, net of VAT 9%

Table 15. Indicative annual average natural gas prices.

The minimum contract duration for households is usually one year, after which, there are no any obligations (financial or others) for the customer who wish 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.

Consumer's complaints/inquires on gas are 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). There are no detailed quantitative data of incoming complaints/inquires on gas.

In the absence of statistical data on complaints/inquires classification, only a rough estimation of the complaint/inquiry nature may be given. The more frequent subject of cases registered to RAE were concerned with:

- transparency on price determination especially in relation to other competitive fuels
- discrimination of prices between two companies of gas supply that hold a license for different geographical areas
- delays on new connection inquires.

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 2008, as reported by the HTSO, is shown in the next table.

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

Table 16. Energy and peak power demand 2005-2008 for the interconnected system (Source: HTSO)

With the total demand in the non-interconnected islands amounting to 5120.2 GWh, the country's total consumption in 2008 was **60.8 TWh** (including about 3320 GWh of losses). Since each of the non-interconnected islands is supplied by a small autonomous power system, a synchronised peak-demand cannot be calculated.

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 international economic crisis and an unusually mild winter and cool summer, the actual consumption in 2008 was below the one predicted under the "low" scenario. No updated forecast has been published yet by the HTSO.

Table 14 reports the long-term forecast for energy demand in the interconnected system until 2030 that was published by the National Energy Strategy Council (SEES) in 2009, after the first effects of the economic crisis had become obvious. The reference scenario is based on average annual growth (0 increase in 2008 and -4.5% in 2009); two more scenarios that reflect the country's effort to improve energy efficiency are also included.

	Reference Scenario	Energy conservation scenarios	
		Most probable	Desirable
2010	59.2	58.8	58.8
2015	65.6	63.7	63.7
2020	74.1	67.7	67.7
2025	82.0	74.2	70.3
2030	89.1	79.8	72.1

Table 17. Long-term scenarios / forecasts for energy demand in the interconnected system (Source: SEES).

Generating Capacity and Fuel Mix

On 31.12.2008 the total 12427.0 MW of total net generation capacity in the interconnected system was distributed as follows:

Plant type	Net installed capacity (MW)	%
Lignite	4808.1	38.69
HFO	718.0	5.78
GTCC	1962.1	15.79
Natural gas – other	486.8	3.92
Hydro plants	3016.5	24.27
RES and small Cogeneration	993.5	7.99
Large-scale CHP	334.0	2.69
Other Cogeneration	108.0	0.87
Total	**12427.0**	**100.00**

Table 18. Installed capacity as of 31.12.2008 in the interconnected system.

Figure 3 demonstrates more clearly the country's dependency on fossil fuels and shows the forecast for the country's generating capacity, according to the *UCTE System Adequacy Forecast 2008-2020* Report.

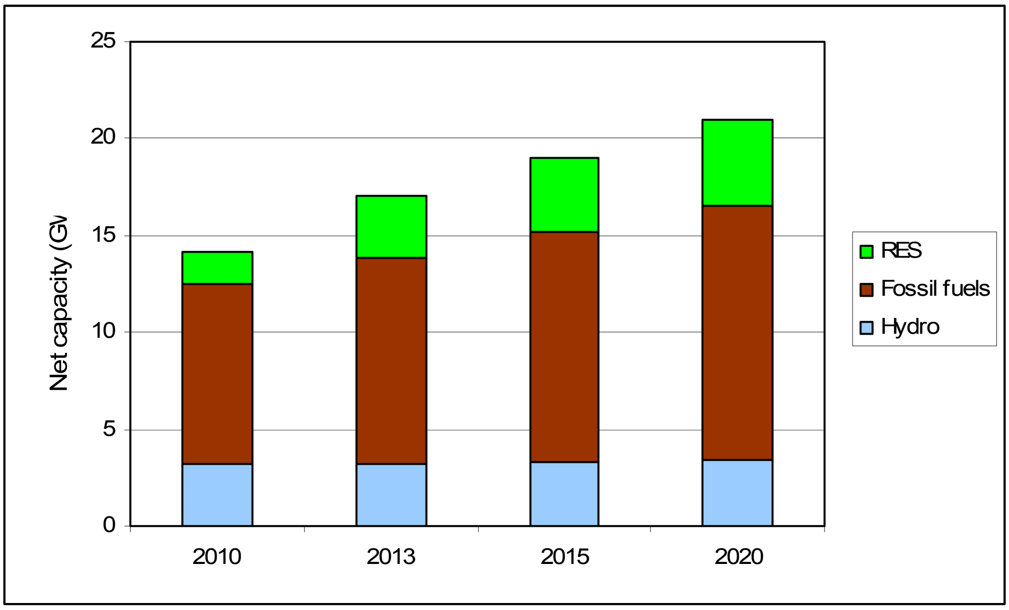

Figure 3. UTCE forecast for net generating capacity.

Concerning RES, the licensing progress per technology is presented in the following Table. By 31.12.2008, 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	883.8	85.1	978.0	83.1	6665.2	89.5	544.6	81.6	41384.6	87.4
BIOMASS	33.9	3.3	21.2	1.8	94.8	1.3	24.5	3.7	510.0	1.1
GEOTHERMAL	0.0	0.0	0.0	0.0	8.0	0.1	0.0	0.0	335.5	0.7
SMALL HYDRO	119.3	11.5	102.3	8.7	555..1	7.5	98.0	14.7	2042.6	4.3
PVs	1.8	0.2	75.0	6.4	123.4	1.7	0.7	0.0	3063.3	6.5
TOTAL	**1038.8**	**100.0**	**1176.4**	**100.0**	**7446.4**	**100.0**	**667.9**	**100.0**	**47336.0**	**100.0**

Table 19. Licensed RES plants in the interconnected system as of 31.12.2008

Regarding the fuel-mix in 2008, the country's dependency on fossil fuels, but also on imports, is evident from Table 16. It is worth noting that, of the 2.16 TWh from RES, about 0.6 TWh are injected to low and medium voltage and is, therefore, not being accounted for in the HTSO's balance presented in Table 16.

	Interconnected system only		Non-interconnected islands		Total	
	TWh	**%**	**TWh**	**%**	**TWh**	**%**
Lignite	29.87	51.99			29.87	47.33
Fuel Oil	3.51	6.11	5.08	89.75	8.59	13.61
Natural Gas	13.33	23.20			13.33	21.12
Large Hydro	2.97	5.17			2.97	4.71
RES	2.16	3.76	0.58	10.25	2.74	3.34
Net Imports	5.61	9.77			5.61	8.89
Total	**57.45**	**100.00**	**5.66**	**100.00**	**63.11**	**100.00**

Table 20. Generation Fuel Mix at the end of 2008 (Source: HTSO & PPC's Islands Network Operations Department)

The fuel-mix for the non-interconnected islands is also worth pinpointing: 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 10%, as compared to a 3.76% 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 may be further exploited.

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

Licensing & Tenders for new capacity in the interconnected system

There has been increased interest for investments in the interconnected system. Appendix II shows the major licensed thermal plants to be commissioned in the next few years, adding up to a net capacity of about 4400MW. No new units entered the market during 2008, although a 334 MW unit of Aluminium of Greece S.A., now owned by Endesa Hellas S.A., begun commissioning and acceptance trials. During the summer time this unit injected significant amounts of power, especially during peak-load periods. A serious breakdown did not allow the start of the commercial operation of the plant, which is now expected in the fourth quarter of 2009.

As far as tendering for new capacity is concerned, and as mentioned in last year's report, under the provisions of Law 3175/2003 and the new Grid and Market Operation Code, in May 2006 HTSO launched a tender for the installation of new generation capacity, for approximately 400 MW. The winning bidder will benefit from an income guarantee from the HTSO, to cover his fixed cost where he fails to obtain at least 70 per cent of those costs from his participation in the day-ahead market. According to the provisions of the Tender, the maximum annual guarantee is set to 92,000€ per available MW-year, the minimum to €35,000 per MW-year and it will be given for 12 years. Although the contract between the HTSO and the successful bidder was signed in July 2008, a later decision of the Central Archaeological Council challenged the existing installation license. Since then a court's final decision is expected.

There were no investments commissioned or retired during 2008, except for 103.6 MW of renewables in the interconnected system and 12.34 on the islands.

5.1.2. **Incentives to build capacity: The Capacity Adequacy Mechanism**

The Greek Capacity Adequacy Mechanism aims to ensure long-term capacity availability and is based on the obligation of the suppliers to present sufficient guarantees in this direction. Its design is similar to the one of the Northeast US capacity markets (PJM, NYISO, ISO-NE), adapted appropriately to the structure and characteristics of the Greek electricity market[6]. Moreover, the Mechanism aims to reduce the generators' business risk, by guaranteeing part of their fixed costs, and the smooth fluctuation of prices in the wholesale market, due to the reduction of the short-term risk of the generators.

According to the Capacity Adequacy Mechanism rules, generators issue annual Capacity Availability Tickets (each corresponding to one MW-Available Capacity) reflecting their total net generating capacity. The Tickets are submitted to the CAT Register, kept by the TSO, and constitute a call to the suppliers for the conclusion of Capacity Availability Contracts. Moreover the two counterparties are encouraged to sign, independently of the CAM, bilateral financial agreements in the form of Contracts for Differences (CfDs) or Call Options.

Capacity Availability Contracts is on the other hand the only way for the suppliers to cover their Capacity Adequacy Obligations, assigned to them according to the energy bought by them from the wholesale market during the periods of increased probability of loss of load, as defined by the TSO. The calculation of the Obligations takes into consideration the required capacity reserve margin, determined yearly by the Minister of Development, based on RAE's opinion following a recommendation by the TSO.

In case a load representative does not cover all of its Obligations, he is charged with the Non Compliance Penalty for the part of his Obligations not covered by Contracts. Thus the Penalty defines in some sense the price cap for available capacity. The Penalty value is set by RAE for each Reliability Year (currently equal to 35,000 €/MW-Available Capacity), considering amongst other factors the capacity reserve margin and the cost of adding new generation capacity to the Greek electricity system.

When capacity shortage is foreseen and is not expected to be covered by Independent Power Producer initiatives, the TSO may proceed to a tender for the pre-purchase of Capacity Availability Contracts, corresponding to new generating units. The Contracts pre-purchase is done on behalf of the future suppliers and customers, to whom the TSO should transfer the Contracts as soon as possible via an auction and aims to guarantee the minimum required income for the new units - for the part of the capacity contracted by the TSO, facilitating their financing.

During the Transitional period, until January 2010, and due to the possible difficulty in the conclusion of Contracts between suppliers and generators, the following alternative Transitional Mechanism is offered:

- Generators may conclude Capacity Availability Contracts with the TSO.

[6] A detailed review of the Capacity Adequacy Mechanism rules may be found in the *Grid and Market Operations Code*.

- The Obligations of suppliers may be covered by the above Contracts, upon conclusion of a “Contract for Participation in the Transitional Capacity Assurance Mechanism” between the suppliers and the TSO.
- A regulatory set price per MW of Availability is received by all participating generators depending on their unit availability. The respective cost is distributed amongst the suppliers participating in the Transitional Mechanism, according to their Capacity Adequacy Obligations.
- The value of the uplift has been set equal to the Non Compliance Penalty, at 35,000 €/MW.

Finally, it is worth noting that, so far, all market participants have participated in the Capacity Adequacy Market only through the Transitional Mechanism. Moreover, as noted right above, the TSO has conducted a tender for the pre-purchase of Contracts, awarding the relative contract to a 440 MW CCGT unit to be constructed by 2010.

5.1.3. **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 the interconnected with this system islands. The set of criteria applied by the HTSO in planning the development of the transmission system aim to achieving, at all times, the transmission of electricity in a secure, reliable and most economic manner, applying transparent, unbiased and non-discriminatory criteria, while taking into account the principle of providing 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 t access to anyone wishing to connect to the transmission system. Critical parameters are the foreseen power ransmission 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 development projects are specified, as well as the progress timeframe and the 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 necessary system development 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 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 wind parks and new thermal power stations. The full project will be operational by year 2011.

- Expansion of the 400 kV transmission system to the south part of the interconnected system. Three new EHV substations will be erected for this purpose in the Peloponnesus area. By year 2012, a large part of this project is expected to be in operation. The reinforcement of this area will provide increased security as well as additional transmission capacity for new RES in Peloponnesus.
- A second EHV substation in the area of Thessaloniki which is expected to be in operation by 2010 and will increase the reliability of the transmission system in northern Greece.
- Connection of the Cyclades islands with the interconnected system through a DC or AC submarine link. Aim of this project is not only reduced PSO charges for the supply of these islands but also transfer of power from wind parks to the interconnected system. The project is planned to commence in year 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 will take place in 2009. This increase is 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 major interconnection projects underway are the following:

- Interconnection with Turkey: Consists of a 100 km EHV line (400 kV, nominal capacity 2000 MVA), with 40 km in the territory of Greece. Construction was completed in February 2008. However, synchronization of Turkey with the UCTE system will not take place before improvements in the frequency control of the Turkish system take place, in order to comply with UCTE rules. According to the latest update by HTSO on this issue, the turkish system operator is in the process of implementing a number of counter-measures. The island mode operation tests of the turkish system are expected to start within the first quarter of 2010. If these tests are successful, Turkey is expected to request the trial synchronous operation of the turkish system with the UCTE system. The duration of this trial operation is typically one year. Apart from the transmission line between Turkey and Greece, two more 400 kV transmission lines between Turkey and Bulgaria will be used for the interconnection of the turkish system with the UCTE system.

- 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

At the end of 2008, RAE published an extensive report on the security of gas supply in Greece, providing a thorough analysis of the characteristics of the Greek situation regarding long/short-term demand forecast and patterns, supply diversification issues and infrastructure development requirements and establishing a work plan for next year with the TSO, DESFA SA.

This section contains information extracted from the aforementioned report, in accordance with Directives 55/2003/EC and 2004/67/EC. All data referring to Gas quantities are provided in both units Mtoe (based on gas with a HHV of 9600Kcal/Nm^3) and bcm (at standard conditions of 1 atm and 15°C).

5.2.1. **Current levels of gas consumption and expected future demand**

The demand for Natural Gas in 2008 was 4 bcm, out of which approximately 75% served the Power Generation Sector, as shown in Table 21.

	bcm @ 15°C	Mtoe (HHV)
Power Generation	2.97	2.70
Industry	0.68	0.62
Commercial & Domestic	0.39	0.35
Total	4.03	3.67

Table 21. Sectoral demand in 2008

Forecasted demand for 2008 did not materialize partly due to unexpectedly high hydraulicity, extended fuel switching due to high gas prices and reduced electricity demand attributed to the financial crisis and mild weather. During 2009 gas demand from the power generation sector is expected to decrease even further to approximately 60% of last year's value and less than 50% of forecasted values. Demand is expected to start rising from 2010 onwards as indicatively presented in the following table 26. Commercial and domestic demand is expected to increase steadily according to the expansion plans of the Gas Distribution Companies (GDC's). Expected future demand for the next three years is presented below in Table 22.

	2009		**2010**		**2011**	
	bcm	**Mtoe**	**bcm**	**Mtoe**	**bcm**	**Mtoe**
Power Generation	2.11	1.92	2.60	2.36	2.73	2.49
Industry	0.73	0.66	0.79	0.72	0.84	0.77
Commercial & Domestic	0.54	0.49	0.65	0.60	0.76	0.69
Total	3.38	3.07	4.04	3.68	4.34	3.95

Table 22. Expected future demand (RAE's estimates)

The values of this table 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,
- average to high hydraulicity through 2011, and
- average to high availability of energy for exports to Greece from the southeast region.

Outlook for demand ten years ahead can be very inaccurate, particularly due to uncertainties on global issues such as the EU ETS, the oil prices, as well as local issues such as the participation of Coal and Renewable Energy Sources into the energy mix within this time frame. Given the uncertainties, we provide three different assessments, one coming from DEPA S.A., assuming business as usual and increasing sales, and three different figures based on a Long-Term Planning study (LTPS) published last year by the Ministry of Development as well as the *Annual Report on the Long-Term Energy Plan,* published this year by the *National Energy Strategy Council* . The data refer to five year intervals extending to 2020. The presented data refer to the interval between 2015 and 2020 which includes year 2018.

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 23. 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 2008 was zero in Greece. Currently, the sole supplier in the country, DEPA SA, imports gas primarily through long term contracts from 3 different sources, namely Russia, Algeria and Turkey. In 2008 several spot LNG cargoes were unloaded at the LNG Terminal of Revithoussa, supplementing the quantities supplied via long term contracts. Figure 4 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 24.

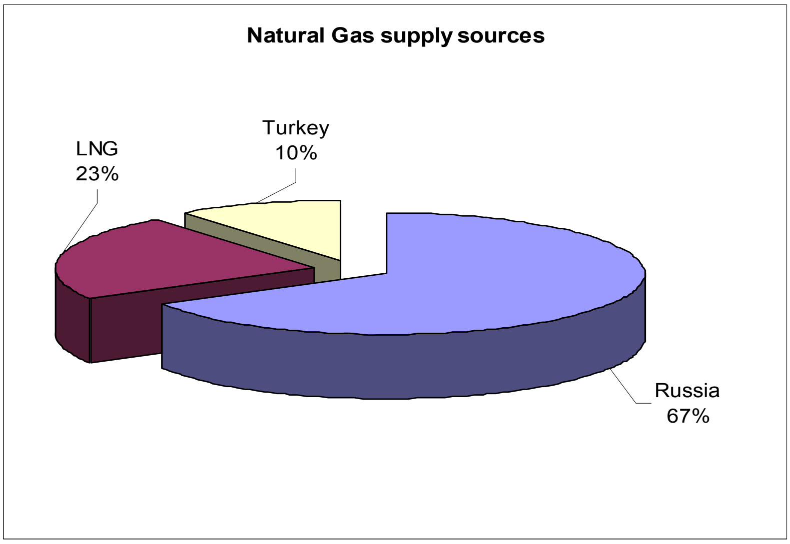

Figure 4. Natural gas sources

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

Table 24. Natural gas contracted annual quantities.

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Table 25 presents the anticipated supply – demand balance for the next three years based on the expected demand and the existing long-term supply contracts. With the revised, significantly lower gas demand forecasts, existing Supply contracts are expected to meet demand through 2011.

	2009		2010		2011	
	bcm	**Mtoe**	**bcm**	**Mtoe**	**bcm**	**Mtoe**
Demand	3.38	3.07	4.04	3.68	4.34	3.95
Supply Contracts	4.1	3.7	4.4	4.0	4.4	4.0
Supply Gap	0	0	0	0	0	0

Table 25. Expected Supply-Demand balance.

Figure 5 below shows the expected demand - supply balance projected to 2018 according to the scenarios presented in Table 23. The high-demand curve corresponds to DEPA's demand forecast, while the low-demand curve corresponds to scenario No 3 of the above table.

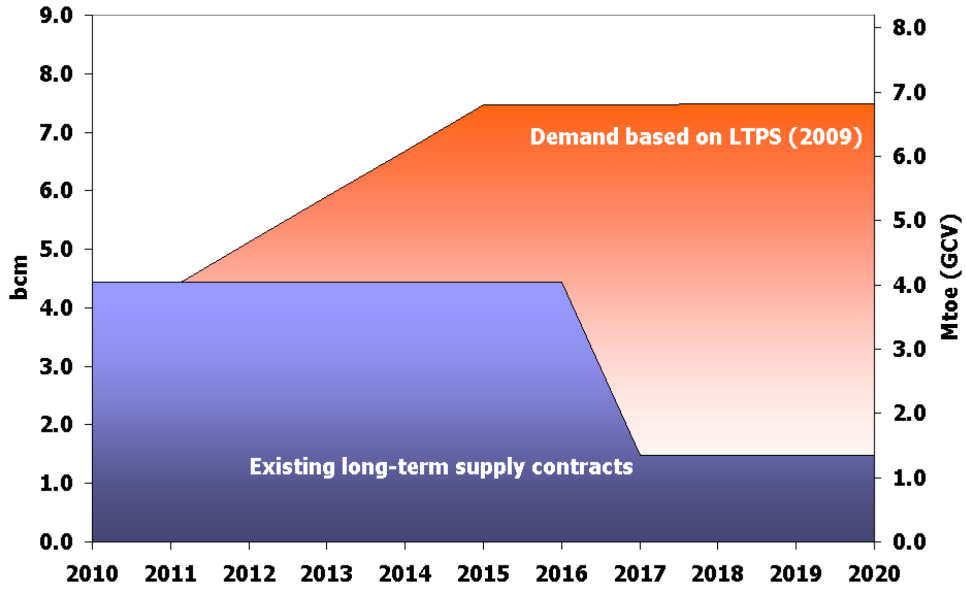

Figure 5. Natural gas supply-demand balance 10-year forecast

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

The TSO, being responsible for operating, maintaining and developing the NGTS, by means of cleaning pigs, follows a regular cleaning and internal inspection program for the pipeline network 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 who 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 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 at Revithoussa and elsewhere
- underground storage facility
- extension of the Dual Fuel obligation to all NG fired powerplants
- 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 LNG terminal is imported to the System. Table 26 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	0.74	0.67
Sidirokastro	5.5	5.0	4.01	3.65
AG. Triada (LNG Terminal of Revithoussa)	4.8	4.4	2.11	1.92
Total	17.4	15.8	6.86	6.24

Table 26. Natural gas entry point capacities.

The capacities in columns [1] refer to the max technical capacity at the border, according to the TSO, without considering either the upstream network capacity, or the downstream constraints. In contrast, data in columns [2] state the known capacity that the upstream network can provide. The data regarding the Turkish network have not yet been provided to the Greek TSO by its Turkish counterpart, so for this entry point that contracted quantities are used. 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.

Gas delivered to the entry point at Sidirokastro cannot exceed 11.5 million Nm3/hour, according to Bulgartransgas (Operator of the Bulgarian transit system), due to upstream network limitations. Assuming a load factor of 90%, this value corresponds to 4 bcm per annum.

The data in table 30 do not take into consideration downstream system limitations attributed mainly to the absence of a gas compressor along the main pipeline traversing from North to South. These limitations are expected to be removed by the scheduled installation of a compressor station at N. Mesimvria by the end of 2010, thereby allowing the transportation of the quoted entry capacities in Table 26 to southern system exit points.

The following Table 27 lists the TSO’s investment plans which are planned to add import capacity to the NGTS.

Project	Realization by
Compressor station	2010
3rd LNG Tank at Revithoussa	TBD

Table 27. Natural gas TSO investment plans

A fourth project still to be approved involves the expansion of the 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, realization is expected around 2014.

To RAE's knowledge, there is no information regarding any forthcoming production capacity investment within the Greek territory.

5.2.6. **Security of supply standards**

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 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 interruption contracts provided for in the Law and quoted in paragraph 5.2.4
- the Security of Supply levy for the remuneration of the interruptible customers who use alternative, higher cost, fuel.

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 powerplants have recently been altered, granting the option between maintaining dual fuel capability with liquid fuel stored on site and 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 interruption contracts are considered in order to give incentives to powerplant operators located on sites with port facilities or near refineries, to opt for the dual fuel at site option.

The above provisions present no impact to gas market players since none are directed to N. Gas suppliers. The provisions are targeted to gas customers. All Natural Gas customers must pay a security of supply levy on an energy basis. The height of this levy has yet to be decided by RAE; however, it will probably be universal for all consumers with specific reductions considered for customers who have entered into 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 Revithoussa island, which features tanks with a 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 destined 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 in the time frame 2014-2022.

Figure 6. Contractually available Natural Gas through 2022

5.2.9. **The degree of liquidity of the gas market**

Currently there is no spot Gas Market in Greece. All gas transactions are implemented via long term, annual or seasonal bilateral contracts between DEPA and their customers. The main supply contract of DEPA, totalling to more than 1.6 bcm per year, is with the electricity incumbent company PPC SA and its duration is up to the end of 2016. Since no supplier other than DEPA has entered the market yet, the liquidity of the market is very low.

5.2.10. **Incentives for new investments**

According to the existing legislation (Law 3428/2005), DESFA has the obligation to prepare, in regular time periods, a ten-year expansion study of the National Transmission Network. This study includes a draft five-year Development Plan of the Network, which is approved by the Minister of Development, following the consenting opinion of RAE. The Development Plan, which DESFA is obliged to implement, defines its development, reinforcement and interconnection works, including LNG and storage facilities, that are meant to be built within a time period of five (5) years from the adoption of the above Plan, its time schedule and the way of subject works construction as well as their budgetary cost. Such works are incorporated in the Regulated Asset Base of the National

Transmission Network and are, in principle, included in the Network tariffs, along with the corresponding operating costs of DESFA.

In addition, the legislation provides that any person other than DESFA, who wishes to develop gas infrastructure in Greece, may apply for a license for an Independent Natural Gas Network (INGN). The license is granted by the Minister of Development, following the simple opinion of RAE. The applicable default regime for any INGN, including LNG and storage facilities, is the regulated third party access, i.e. the rules for access to the INGS as well as the related tariffs are approved, according to the provisions of the Law, either directly by RAE, or by the Minster of Development following the opinion of RAE. However, should the investors so wish, they can apply for an exemption from all or part of the regulated TPA regime, following the procedure described in the corresponding provisions of Law 3428/2005, transposing the corresponding provisions of Article 22 of the Directive 2003/55/EC.

The provisions of the Greek gas legislation are such that allow for the provision of specific incentives for the development of infrastructure that might be proven necessary for the development of the natural gas market. For the time being, there has been no need for the provision of such incentives.
DESFA is currently implementing the investments already included in its initial Development Plan and incorporated into the existing network tariffs. These include, besides the already operational new interconnection with Turkey and the increase of the sent out capacity of the LNG Terminal at Revithoussa, the construction of a compressor station and high pressure branches to new consumers (mainly power plants).

5.2.11. **Progress in interconnection and transit projects**

Interconnection Greece-Italy (IGI)

As explained in the 2008 report, according to the terms and conditions of the exemption decision granted to the project, the sponsors were obliged to perform, within one year from the approval of the exemption, an open season for an additional 0.8 bcm of capacity, as a minimum, to be offered to third parties, under terms and conditions which will be approved by the Regulatory Authorities of Italy and Greece.

In June 2008, the Greek and Italian authorities approved the regulation on the Open Season Procedure, and the (non-binding) Expression of Interest Phase of such procedure was launched immediately thereafter.

According to the aforementioned regulation, the total capacity offered to third parties was defined to 1 bcm/year, in ten lots of 0.1 bcm/year each.

In December 2008, the project sponsors submitted for approval to the Greek and Italian authorities' drafts of the transportation agreements and tariffs to be offered to the interested parties during the second phase of the open seasons (Binding Offers). This is expected to be approved within 2009.

Trans-Adriatic Pipeline (TAP)

TAP refers to a transit pipeline with the view to transport gas mainly from the Caspian region to Italy, through Turkey, Greece and Albania.

In June 2008, an application for the ownership and operation of the Greek part of this project as an Independent Gas System, according to the Greek Gas Law, was filed to RAE and the Ministry of Development, by Trans Adriatic Pipeline (TAP) AG, a joint-venture of EGL and StatoilHydro. The application has being assessed; however, the final decision will be taken after putting into force of the Authorisation Regulation (see sections 2.2 and 4.1.3). At the same time the sponsors of the project submitted a request to DESFA S.A. for reserving capacity of 10 bcm/year at the Greek-Turkish interconnector. The request has been published in RAE and DESFA S.A. websites and will be assessed along all other similar requests upon the completion of the Network Code and in accordance with its provisions.

South Stream

The Interstate Agreement between Russia and Greece regarding the South Stream project was finally concluded in April 2008 and was ratified by the Greek parliament in October of the same year.

Interconnection Bulgaria-Greece (IBG)

At the end of 2008 discussions started between the governments of Bulgaria and Greece, for the construction of a new interconnector of the natural gas systems of the two countries. Further developments will be presented in the next National Report.

6. Public Service Issues

Electricity

As thoroughly explained in the previous sections, all end-user tariffs (except HV) are still regulated. Nevertheless, during 2008, intensive work was done, following a ministerial decision in December 2007, a) that all PPC's tariffs should be unbundled, in order detail the separate charges for energy, transport, distribution and PSO and b) to set a timetable that all cross-subsidies and distortions within the tariffs of the categories of customers, or even the customers of the same category should be gradually removed in a period of three year. All necessary studies were made available and it is expected in the last quarter of 2009 all tariffs to be appropriately unbundled, in order to promote transparency to the retail market.

Some groups of vulnerable customers under specified -conditions (e.g., families with more than three children) enjoy a discount tariff by the Suppliers, as a measure of social support. RAE has undertaken a study on the appropriate treatment of other vulnerable customers, such as disabled, and the associated PSO cost. The study is expected to be completed in 2010, due to the dispersed source of information on quantitative data.

In a Ministerial Decision in July 2008, a special "poverty" tariff was enacted. Following that Decision RAE sent its opinion, regarding the awarding criteria for this tariff, including the consumption up to 800 kWh in a 4 month period, excluding summer houses and a maximum annual income, equal to the tax free income as decided by the Ministry of Finance. Nevertheless, this opinion is still pending to be approved by the Minister of Development.

According to the law 2773/1999, PPC has the obligation of the last resort supplier, since other suppliers are not yet developed enough in order to be able to hold this obligation

Statistical data on disconnections due to non-payment are not available. Recently, PPC introduced a new procedure on disconnection due to non-payment. If the bi-monthly bill is not paid in due time (30 days), the pending amount is transferred to the next bill. In this way, the consumer gets a total of 60 days tolerance period. After that, PPC has the right to disconnect the consumer. There is no limitation for disconnections in winter time.

Natural Gas

There were no developments regarding the legal framework for imposing PSOs compared to 2008.

Regarding the EPAs and in accordance with the respective concessions licenses, there are only some administrative measures that facilitate disabled customers and the elderly in their transactions with their provider. For these customer categories, there is also a prohibition on disconnecting customers, due to non-payment, from November through February.

Appendix I. The wholesale electricity market under the *Grid and Market Operation Code*

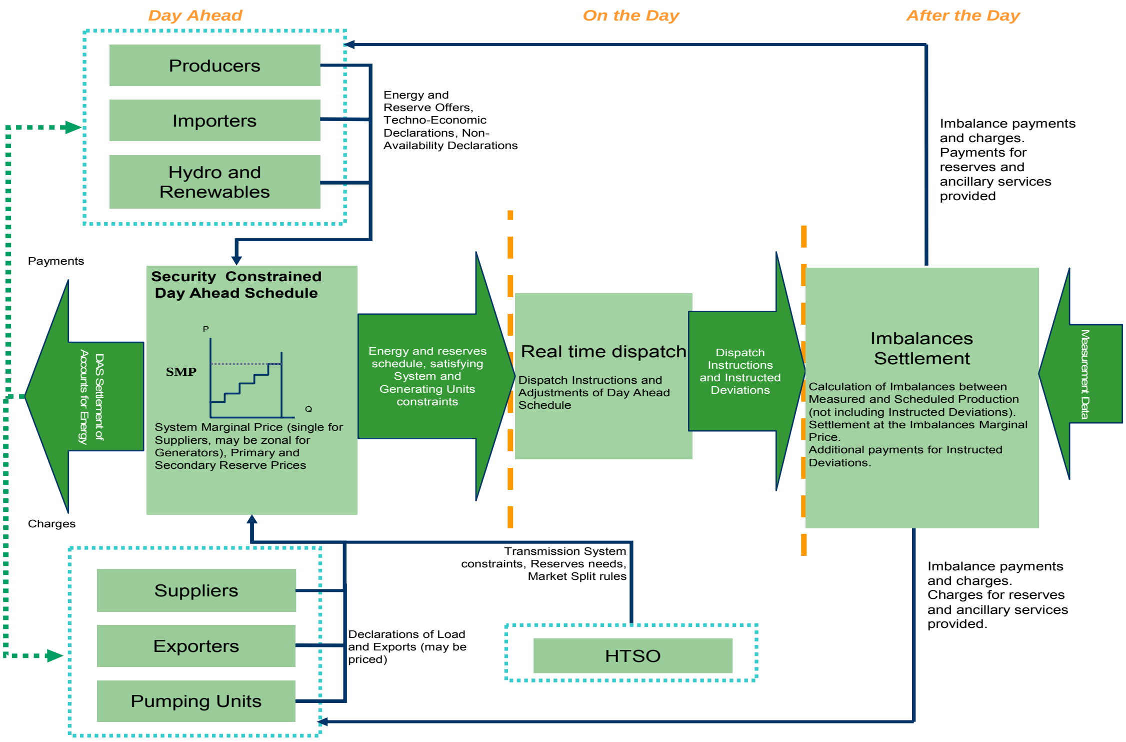

Figure 1. Greek Wholesale Electricity Market Design Schema

The Day-Ahead (DA) Market.

The DA market constitutes the first stage of the wholesale market process and comprises of the following individual markets, which are co-optimized:

- Energy Market
- Energy Reserves Market
- Market mechanism for the allocation of the production near the points of consumption (Zonal Pricing).

On a daily basis, participants in the Energy Market submit offers (bids) for energy generation (demand) in the form of a 10-step stepwise increasing (decreasing) function of prices (Euro/MWh) and quantities (MWh) for each of the 24 hour periods of the next day. Producers also submit offers for the Reserves Market, as a single pair of price (Euro/MW) and quantity (MW) for each reserve category (Primary & Secondary reserve[7]).

After the gate closure (at 12.00 pm), the HTSO solves the DA problem based on the bids and offers of the participants. More specifically, the problem is formulated as a Security Constrained Unit

[7] At the time this paper is written there is an open public consultation for expanding the Reserves Market by introducing also Tertiary Reserve offers.

Commitment, maximizing the social welfare for all 24 hours of the next day simultaneously, by matching the energy to be absorbed (according to the load declarations) with the energy to be injected in the System (based on the injection offers, separate for each unit), while meeting a set of constraints. The main constraints are the transmission system constraints, the technical constraints of the generating units and the reserve requirements. The solution of the DA determines how each unit should operate for each dispatch period (i.e. each hour) of the dispatch day, and also the clearing prices of the Energy and Reserve Markets.

The incorporation in the DA problem of the reserve requirements and of the transmission system constraints, which may well constrain the quantity of energy that flows from the North to the South, minimizes the deviations of the DA Schedule from the real time operation of the units and therefore reduces the volume of Imbalances Settlement transactions.

The resulting hourly clearing price of the DA energy market (System Marginal Price - SMP) is the uniform price at which the load representatives buy the energy they expect their customers will absorb from the System and at the same time is the price paid to the producers. In most cases the SMP takes a single price for all the producers, independently of their geographical position. However, if the transmission system constraints are activated, this will result in two different Marginal Prices for generation, one for the North and one for the South System. The differentiation of the SMP for the producers reflects the zonal value of electricity and provides the necessary economic signals to the producers for the construction of their units in sites where their value to the System is higher, so as to remove the existing constraints.

All the procedures of DA, including financial settlement of the resulting energy transactions, are concluded within the day that precedes the dispatch day (i.e. the day of the physical delivery of energy), referred to as “Day Ahead”.

<u>The Real Time Dispatch operation (RTD).</u>

In real-time, i.e. every 5 minutes, the HTSO dispatches generating units already committed by the DA market in order to meet the load and minimise generation costs while ensuring overall system reliability. To this objective, the problem is formulated as a linear program, with objective to minimize generation costs subject to constraints for meeting the load (here as load is assumed the load projection for the next 5-min interval), generation units technical constraints, network constraints and reserve requirements

<u>Imbalances Settlement.</u>

The Imbalances Settlement includes the clearing of transactions with respect to energy deviations (which can be instructed or uninstructed), Ancillary Services and Uplift Accounts. Thus, during the Imbalances Settlement and for each dispatch day, HTSO calculates:

- The quantity of energy corresponding to deviations, instructed or uninstructed, which are thereby attributed to each participant for each dispatch period.
- The debit or credit corresponding to the imbalances of each participant.
- The payment of each participant for the provision of Ancillary Services through the Uplift Accounts.
- The debits and credits of the Uplift Accounts.

In the above framework, calculation of energy deviations is performed separately for every participant, with separate calculations for each load declaration, each generation unit and each interconnection. In every case a specific tolerance margin is taken into consideration when calculating energy deviations.

The Imbalances Settlement procedure is defined as an administrative procedure which does not correspond to a Balancing Market. In this context:

- The Imbalances Settlement clears at a uniform price, the Imbalances Marginal Price.
- HTSO, in its capacity as being the Market Operator at the same time, should aim that the cost of the Imbalances is allocated to the partiers that cause them.
- HTSO should also aim towards the minimization of the total Imbalances Settlement cost.

The Imbalances Marginal Price is calculated hourly using the DA Schedule algorithm, but considering the actual availability of the units, RES generation and load that was absorbed. Moreover, all instructed deviations by the producers are paid at least at their marginal cost. The Imbalances Settlement procedure is completed within 4 days following the dispatch day.

Appendix II. List of licensed investments in thermal units

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 III. List of licensed suppliers at the end of 2008

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

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

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