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Annual Report
To the European Commission
2006-2007

Regulatory Authority for Energy (RAE)

Athens – JULY 2007

LIST OF ACRONYMS

DEPA:	Public Gas Corporation S.A.
DESFA:	National Natural Gas System Operator
DSO:	Distribution System Operator
EPA:	Gas Distribution Company
GHG:	Greenhouse gases
HGTSO:	Hellenic Gas Transmission System Operator
HTSO:	Hellenic Transmission System Operator
NGS:	Natural Gas System
NNGS:	National Natural Gas System
PPC:	Public Power Corporation S.A.
RAE:	(Hellenic) Regulatory Authority for Energy
SMP:	System Marginal Price
STA:	Standard Transportation Agreement for access to the gas transmission system
TDSO:	Transmission and Distribution System Operator
TSO:	Transmission System Operator

1 Foreword

2 Summary \ Major Developments in the last year

2.1 Basic organizational structure of the regulatory agency

RAE is an independent administrative authority established on the basis of the provisions of Law 2773/1999, which aimed to the harmonisation of the Hellenic legal order to the provisions of Directive 96/92/EC for the liberalization of the electricity market. RAE, enjoys financial and administrative independence.

Pursuant to the provisions of Law 3426/2005 amending Law 2773/1999, RAE's board is composed of 7 members, so as to enhance effectiveness. The President and the two Vice-Presidents are appointed by a Decision of the Cabinet of Ministers acting on a proposal of the Minister of Development and following the opinion of the competent Parliamentary Committee. The other members are appointed by a decision of the Minister of Development.

The criteria for the selection of the members of the authority are scientific proficiency, professional capability and specialised experience in issues pertaining to the responsibilities of RAE. The members of RAE are considered senior civil servants, enjoying personal and functional independence while exercising their duties. Within this framework, the members of RAE are subordinate only to the Constitution, the laws and their conscience and are not obliged to comply with orders or directions issued by public or other institutions and organisations. In order to ensure such independence, RAE members may not be recalled during the term of their office and their revocation or suspension is permitted only in case of serious criminal conviction or persecution.

As already mentioned, RAE is a financially independent body. According to the provisions of Law 2837/2000, RAE charges fees for granting or amendment of licenses in the electricity sector, annual fees for the use of such licenses, annual fees from the companies of the natural gas and petroleum markets, participation to research projects etc. These resources are managed in accordance with the Presidential Decree 139/2001 “Regulation for the Internal Operation and Administration of RAE”, while financial management is subject to ex-post auditing by Independent Auditors and the Court of Auditors.

For the accomplishment of its duties and responsibilities RAE is assisted by an administrative structure, namely the “Secretariat”. The internal organization of the Secretariat is based on the aforementioned Presidential Decree No. 139/2001. According to that Decree, the Secretariat is organized in five (5) Operational Departments (Markets and Competition Dept., Consumers and Environment Dept., Systems Analysis Dept., Energy Planning and International Affairs Dept. and Decision Elaboration and Documentation Dept.) and in three (3) support units (Press and Public Relations, Administration, and Chairman´s Secretariat,).

Currently the Secretariat of RAE consists of 34 experts (namely 13 engineers, 10 lawyers, 5 economists and 6 of other fields) and 22 administrative staff.

In alignment with the provisions of Directives 2003/54/EC and 2003/55/EC, particularly with respect to (a) access tariffs to electricity and gas networks, (b) terms and conditions for the provision of balancing services in natural gas, and (c) issues related to security of electricity and natural gas supply, RAE's competencies and duties in the electricity and natural gas sectors have been essentially strengthened through the provisions of the recently adopted laws 3426/2005, 3428/2005 and 3468/2006.

More specifically, regarding the electricity sector, RAE:

- is responsible for providing simple opinion to the Minister of Development concerning the adoption of the Generation Licenses Regulation and the Supply Code, as well as granting, amending and revoking of generation licenses

- enjoys the right of a consenting opinion to the Minister of Development as far as the Grid and Market Operation Code, the Distribution Network Operation Code and the tariffs for access to the networks.

- approves

    - the methodologies for the access tariffs to the transmission and distribution networks

    - the decisions of the HTSO regarding the implementation details of the Grid and Market Operation Code,

    - the decisions of the Distribution System Operator regarding the implementation details of the Distribution Network Operation Code and

    - the generation adequacy studies conducted by HTSO to establish whether HTSO should issue tenders for new generation capacity.

- provides simple opinion to the Minister of Development for the approval of retail tariffs of the incumbent company (PPC). Such an approval for PPC tariffs is required only for as long as PPC has a share of at least 70% of the retail market.

In the natural gas sector, RAE:

- grants simple opinion for issuing technical regulations for internal and external natural gas installations and for the tariffs to be applied for TPA of electricity generators to the natural gas grid (Law 3175/2003)

- is responsible for supervising and monitoring the compliance of the three concession licensees for the distribution of natural gas (approval of 5-year development plans, ex-post control of supply and connection charges, ex-post control for revenue cap violations and subsequent setting of tariffs and supervision of licensee and customer relationship).

- gives a consenting opinion for the issue of the Operation Codes of the National Natural Gas System, as well as of Independent Natural Gas Systems, while it approves the appropriate methodologies and details for the implementation of such Operation Codes.

- following a proposal by the responsible System Operator, prepares the tariffs Regulation, which lays down the methodology used to calculate tariffs for the relevant activities and is approved by the Minister of Development.

- regulates the terms and conditions for the provision of balancing services.

Regarding the Oil Sector, Law 3054/2002 grants to RAE specific responsibilities and competences; namely, RAE grants its opinion on the issuing of the Authorisations Regulation and the Oil Stockholding Regulation, collects and publishes statistical data regarding the petroleum products market, participates in the Emergency Response Committee for Oil Supply Crises. Besides, in exceptional cases, RAE grants opinion for the imposition of price caps in petroleum product prices.

As far as the energy markets in general are concerned, the main duties and responsibilities assigned to RAE relate to the following subjects:

- Monitoring the operation of all sectors of the energy market (Electricity, Natural Gas, Oil Products, Renewable Energy Sources, Cogeneration of Electricity and Heat etc.). RAE monitors in particular the level of transparency and competition in the energy markets, the management and allocation of interconnection capacity, the time taken by network operators for connections of users and repairs to the networks, the publication of all appropriate information by the networks operators, the terms and tariffs for access to the networks, the unbundling of accounts, and the security of supply.

- Collection and processing of information from companies in the energy sector, while respecting the principles of confidentiality.

- Reporting every two years on security of supply both for electricity and natural gas. A report is published and submitted both to the Minister of Development and the Commission.

- Participation in the pre-parliamentary legislative process through recommendation to the Minister of Development of the appropriate measures related to compliance with competition rules and to the overall protection of the consumers in the energy market.

- Monitoring of the activities undertaken by licensees and access to information by interested parties.

- Imposition of financial sanctions, namely fines, to the violators of the primary and secondary energy legislation.

- Arbitral resolution of disputes between parties on electricity and natural gas legislation.

- Dispute settlement, with respect to complaints against electricity transmission or distribution system operators and the owner of the electricity network, as well as against Natural Gas System and Distribution Operators, on infringements of primary and secondary electricity and natural gas legislation.

- Cooperation with other countries' Regulatory Authorities, international Organisations and the European Commission.

- Reporting on an annual basis to the European Commission on market dominance, predatory and anticompetitive behaviour, on the basis of the appropriate information submitted by the Competition Authority.

While exercising its duties, RAE is obliged to comply with the legality principle. Its decisions, when not solely advisory, are subject to judicial review by the competent Administrative Courts. RAE publishes and submits to the Parliament, via the Minister of Development, on an annual basis, a report giving detailed information about its functioning and acts.

2.2 Main developments in the gas and electricity markets

2.2.1 Main developments in the electricity market

Market structure

There were no major developments concerning the electricity markets structure in Greece during this reporting period. In the wholesale market (interconnected system), the incumbent utility, PPC S.A., retained an approximate 95% market share both in terms of installed capacity and electricity generated. In the retail market, PPC S.A. enjoyed a 99.6% market share during 2006 (as compared to 97% and 98.2% during 2005 and 2004 respectively).

However, it should be noted that interest for the wholesale electricity market by private investors looks more positive than during the previous years. Three private industrial groups have announced their intention to install GTCC units of total capacity in the order of 1200 MW by the end of the decade. Furthermore, interest by private investors for developing coal plants has been registered: three applications for generation license concerning approximately 1600 MW of total capacity have been submitted to the Regulator.

Adequacy of supply and tendering procedures

The current reporting period has been characterized by low water inflows into the reservoirs of the hydroelectric units. This has resulted to a -62.6% generation from such units during the period January 2007 - June 2007, as compared to the respective period of 2006.

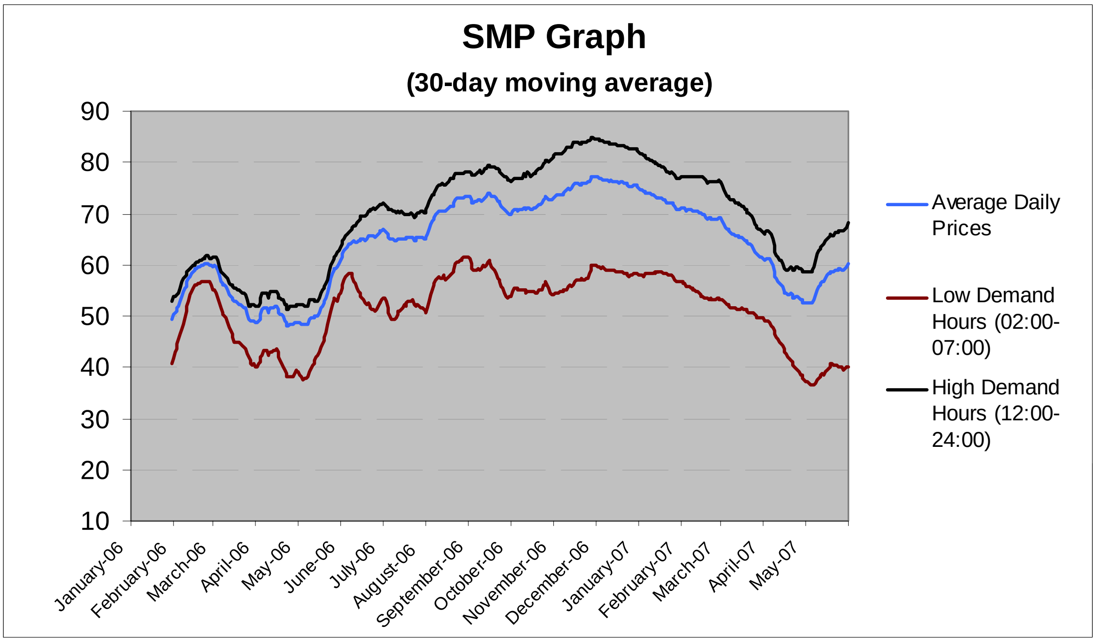
Additionally, during July 2007, a period of several days of sustained high temperatures within the country resulted in new record of peak demand for the interconnected system, which reached 10.600 MW, about 600 MW higher than the previous (August 2006).

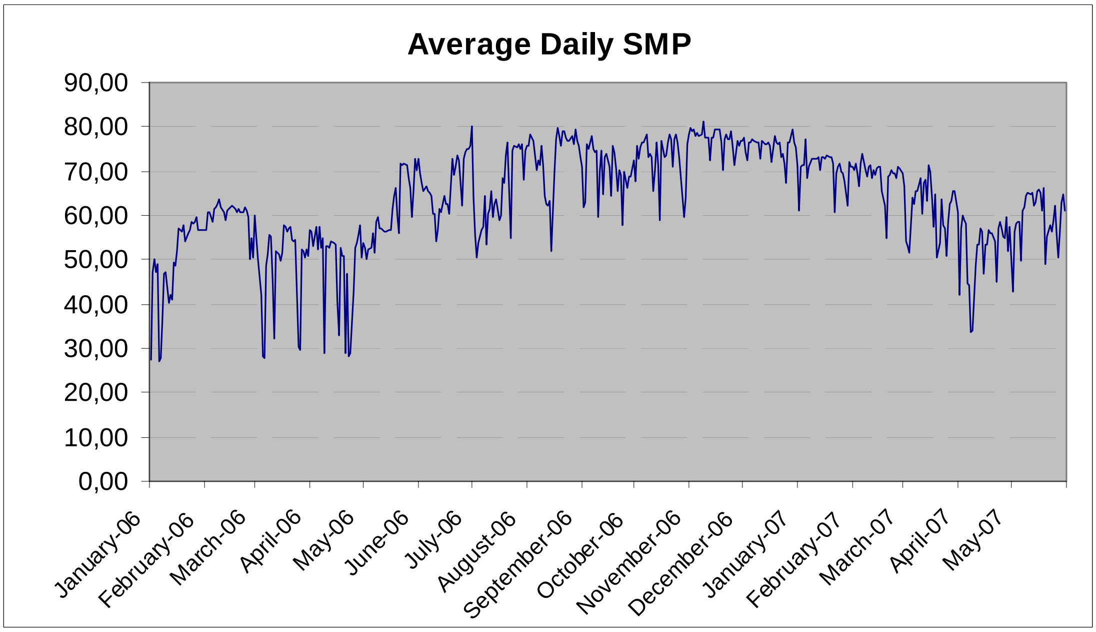
Finally, and as mentioned in last year´s report, under the provisions of Law 3175/2003 and the new Grid and Market Operation Code, HTSO has launched (May 2006) a tender for the installation of new generation capacity, for approximately 400 MW GTCC. The winning bidder will benefit from an income guarantee from the HTSO, covering part of his fixed cost, due to the difficulty of fully covering such costs just by participation in the wholesale energy market. According to the provisions of the Tender, the maximum annual guarantee was set to €92,000 per available MW-year, the minimum to €35,000 per MW-year and it will be given for 12 years. There were 4 participants to the tender and currently the tender is in its final stage, delayed by a complaint filled before the European Competition Committee concerning the procurement proceedings and the legality of the contract to be concluded.

Wholesale electricity market - Price developments

During the first half of 2006 the System Marginal Price (SMP) followed an increasing trend together with a decrease in the observed volatility. This behavior was related to a decision made by RAE concerning the modification of the methodology for the SMP calculation, aiming to face the distortions that held the SMP at artificially low levels and let it take a price closer to its "true value". The average yearly SMP was at 64,13 €/MWh, with its average price during the low demand hours (02:00 – 07:00) at 51,89 €/MWh and during the high demand hours (12:00 – 24:00) at 69,01 €/MWh.

The last quarter of 2006 along with the first quarter of 2007 was characterized by high prices, mainly due to the observed low reservoir levels of the hydro units. During the first five months of 2007, the average SMP was at 62,63 €/MWh, with its average price during the low demand hours at 47,37 €/MWh and during the high demand hours at 69,04 €/MWh.





Retail market opening

- Following the Directive 2003/54 EC and according to the provisions of Law 3426/2005, all electricity consumers, except those with specific provisions regarding the Non-Interconnected Islands, are considered as eligible by July the 1st, 2007. Additionally, and although the Distribution Network Operation Code has not been established yet, the *´Handbook for the management of metering and the periodic reconciliation between Suppliers serving customers connected to the distribution network´,* issued by RAE, along with the decision of RAE on the *distribution network losses factors*, provides for medium and low voltage customers switching.

- During the current reporting period, RAE proceeded further with work on the Distribution Network Operation Code and organised a public consultation for part of it concerning power quality on December 2006.

Unbundling

Concerning unbundling of the distribution system operation, and according to Law 3426/2006, the respective organisational unit of PPC S.A. has to be transferred to the HellenicTransmission System Operator (HTSO) by July the 1st, 2007. The HTSO will then become a Transmission and Distribution System Operator (TDSO).

In addition to the above, a major development promoting the development of the electricity market in Greece was the progress towards a satisfactory unbundling of the integrated company's, PPC S.A., accounts for each of its activities related to the electricity sector. As mentioned and in last year´s report, PPC SA should submit the principles, rules and unbundling methodology and their implementation for the Balance Sheet and Income Statement for 2004 and 2005 according to the provision of the Law 3426/2005. After the submission by PPC SA of the aforementioned items, RAE, with its decision 86/2007, approved the principles, rules and unbundling methodology for PPC S.A. The unbundled accounts of PPC S.A. for years 2004 and 2005 are now published on the company´s web site.

Public Service Obligations

According to Law 3426/2005 (ar.28), the Minister for Development defines the public services in the electricity sector for which an obligation to serve exists. In June 2007, by a Ministerial Decision of 25.6.2007, the following services were defined: (a) supply of electricity to non-interconnected islands and to remote micro-grids with tariffs equal to those of the mainland´s interconnected system and (b) reduced tariffs for the supply of electricity to consumers / families with many children.

2.2.2 Main developments in the gas market

The current reporting period has been characterized by an effort to complete the regulatory framework for the establishment of a competitive and well-functioning gas market in Greece. Although law 3428/2005 (the ´Gas Law´) already transposed the provisions of Directive 2003/55/EC into national legislation, providing a coherent framework for the opening up of the natural gas market, the establishment of the Hellenic Gas Transmission System Operator (HGTSO) and the completion of important pieces of secondary legislation such as the Network Code were necessary but still missing steps in the liberalization process, as reported in last year's national report.

In summary, major developments in the Greek gas market were:

1. Establishment of the Hellenic Gas Transmission System Operator (HGTSO) in February 2007, under the name of "DESFA S.A.". DESFA is the owner and operator of the National Natural Gas System.
2. Approval and enactment of the Standard Transportation Agreement (STA) for access of third-parties to the Transmission System. The STA includes all necessary provisions for access to the high-pressure grid that will eventually be incorporated in the Network Code, currently under drafting.
3. Additions to the TPA tariffs put into force in March 2006, in order to accommodate the cases of peaking power plants and address potential competition problems in the electricity sector.

Market Structure

No changes were recorded on the supply side of the market. Despite the fact that almost 70% of the market is open to competition, the Greek incumbent DEPA S.A. remains, for the time being, the only importer and supplier of natural gas in the country.

Price developments

There isn't an organized wholesale market for gas and therefore there are no any published data available for wholesale prices. Only the gas distribution companies (EPA) publish their prices for sale of gas to end customers.

Market Opening

Currently, gas-fired CHP-generators with annual consumption over 9 Mm3 and all gas-fired power producers are eligible customers. Eligibility right will be expanded to other customer categories, according to the milestones for market opening set in the Gas Law (see also section 4.1.1.2).

Unbundling

The major development regarding unbundling of activities in the gas market was the establishment of the HGTSO, in accordance with the provisions of the Gas Law (law 3428/2005). Other unbundling rules and their application for the rest of the entities active in the market are described in section 4.1.4.

2.3 *Major issues dealt with by the regulator*

2.3.1 Electricity

Beside the evolutions described above, RAE has also been involved in the following major issues related to the operation of the Greek energy market:

1. Amendment of the Grid and Market Operation Code. As the implementation of the new Code started in October 2005, providing for a transitional period of 2 years (its full implementation is expected within 2008) a number of technical issues have arisen and lead to the amendment of a number of articles of the Code, approved by the Minister of Development after the opinion of RAE, among which mainly the following,

   - Bids of generating units below variable cost are only acceptable for the 0-30% range of the units´ capacity range

   - Extension of the deadline for full implementation of the Code to July 2008 (originally Jan. 1st 2008), which was mainly due to the delay in the development of the necessary infrastructure (software applications etc) by the HTSO

2. Issue of RAE’s opinion on details for the application of the Grid and Power Exchanges Code. RAE has expressed its opinion on several issues regarding the application of the new Grid and Power Exchanges Code, among which mainly on the following:

   - RAE´s Decision no. 260/2006 about the ´variable cost of dispatchable hydro units´. This has been set equal to 53 euro/MWh for year 2007.

   - RAE´s Decision no. 76/2007 about the publication of electricity market data as well as cross-border trade data for reasons of transparency, increased competition and efficient operation of the electricity system

3. In view of introducing market mechanisms for the procurement of ancillary services, RAE organized a public workshop during April 2007. During the workshop a review of the international experience on ancillary services markets was presented and prospects for establishing such markets in Greece were discussed.

4. RAE, with its decision 86/2007, approved the principles, rules and methodology concerning the unbundling of PPC S.A.´s accounts for each of its activities related to the electricity sector. PPC SA submitted the unbundling methodology and its implementation for the Balance Sheet and Income Statement for years 2004 and 2005 according to the provisions of Law 3426/2005

5. RAE is currently working intensively on the Distribution Network Operation Code, in order to organise the public consultation and express its final opinion within 2007

6. Concerning electricity end-users tariffs, RAE is currently undertaking a study for estimating the long run marginal costs of generation, transmission and distribution of electricity in Greece. The main objective of the study is to identify all economic costs incurred in the respective sectors (high, medium and low voltage sectors) and thus to contribute towards the establishment of rational and cost reflecting tariff structures. Within the study, an evaluation of the existing tariff structure and definition and analysis of various consumer categories, based on their load profiles, voltage connection level as well as technical and behavioral characteristics shall be performed.

2.3.2 N. gas

RAE was involved in the following issues regarding the natural gas market.

1. RAE prepared, in cooperation with the HGTSO, the Standard Transmission Agreement which establishes all the transitional provisions for TPA to the high-pressure grid. Following a public consultation process, RAE granted its opinion to the Minister of Development who approved the STA. In particular the STA includes the following parts:
   - The procedure for the conclusion of the transportation contract between the HGTSO and the users of the Transmission System (application, qualifications of the applicant, rejection or approval terms).
   - The content of the contract and particular the duration, the services provided by the HGTSO, obligations and rights for the contracting parties, tariff issues, Force Majeure, guarantees, as well as contract amendment procedures.
   - Special annexes which include procedures for the operation of the Transmission System (nominations, allocations, maintenance, emergency procedures, measurements and gas quality, balancing etc.) These provisions will be replaced by the Network Code which is currently under drafting.
2. RAE prepared and granted its opinion to the Minister of Development for the amendment of the TPA tariffs to the NNGS in two cases. The first amendment concerned the establishment of a price cap for peak power producers (Ministerial Decision 1781/2006). The second amendment determines the level of capacity reservation in the gas transmission system for electricity power producers, as a percentage of the technical capacity of each power unit (Ministerial Decision Δ1/5037/2007).
3. In March 2007 and regarding the operation of the NNGS during the scheduled Revythoussa LNG terminal shut-down, RAE prepared the procedures for the operation of the Transmission System and the remuneration of the electricity power producers who would use back up fuel for their operation in the cases of interruption of the supply of natural gas (Ministerial Decision Δ1/Γ/5510/2007).

4. In January 2007, RAE granted its opinion to the Minister of Development regarding the terms and conditions under which an exemption could be granted to the Italy-Greece Interconnector (IGI) project, according to the provisions of article 22 of the Gas Directive.

3 Regulation and Performance of the Electricity Market

3.1 Regulatory Issues [Article 23(1) except "h"]

3.1.1 General

According to the provisions of the Law 3175/2003, which amended the previous Law 2773/1999, as of 1 July 2007, all customers become eligible. However, the Greek Government has filed with the European Commission a request for derogation in accordance to Article 26 of the Directive 2003/54/EC for the micro-systems on all non-interconnected islands (Crete and Rhodes not included). According to the request, there will be no eligible customers on these islands and the exclusive supplier and generator (with the exemption of RES, CHP and autoproducers) will be the incumbent PPC S.A.

3.1.2 Management and Allocation of interconnection capacity and mechanisms to deal with congestion

3.1.2.1 Congestion on interconnections

Greece is electrically interconnected with its northern neighbouring countries (Bulgaria, FYROM and Albania) and with Italy (submarine, 400 kV DC link, 500 MW rated capacity). Northern interconnections are congested for imports to Greece while the Greece-Italy cable is congested in the export direction.

Under normal transmission system availability conditions in the Balkans area, the congestion appearing on the northern interconnections is associated with transmission constraints outside the Hellenic system (Serbia-FYROM, north interconnections of Albania, FYROM-Bulgaria). On the other hand, congestion on the Greece-Italy interconnection is associated exclusively with the capacity of the link itself.

With respect to the northern interconnections, the meshed topology of the transmission systems in the Balkans area historically has posed difficulties in calculating individual NTC values for each of these interconnections. As a consequence, in previous years and until the end of 2006, a combined NTC approach has been followed by HTSO for calculating and allocating capacity on the northern interconnections for imports to Greece, taking into account security constraints and forecasted energy balance data provided by the neighbouring systems' TSOs. In 2006, joint efforts undertaken by the Hellenic TSO and the TSOs of Bulgaria, FYROM and Albania resulted in agreeing to a common methodology for NTC calculation on each of the northern interconnections, which has been put in operation since the beginning of 2007.

3.1.2.2 Interconnection congestion management in 2006

Until the end of 2006, the procedure for allocation of import capacity though the Northern Interconnections in the form of physical transmission rights was set by decision of the Minister of Development, according to the provisions of the 2001 Grid Code.

According to this decision, 70% of the estimated base-load combined Net Transmission Capacity of 600 MW, or at a minimum 420 MW, is made available for long term (annual) allocation. Out of this annual capacity, 52,4% (i.e. 220 MW) is directly allocated to the Public Power Corporation, while the remaining (200 MW) is made available to eligible customers (exclusively for their own use) and suppliers, by explicit auction.

The remaining NTC of 180 MW, increased by long term capacity which has not been allocated through the annual auction and including long term capacity which has been allocated but is not nominated, is made available to Suppliers and eligible customers for day ahead nomination (implicit allocation), with PPC however having priority on 83,3% of this daily allocated capacity.

The annual explicit auction for import capacity on the northern interconnections resulted in allocating 200 MW to 7 suppliers in the Greek market at the price of 40.000 €/MW. Bids were received from 13 suppliers and eligible customers with a total demand for import capacity of 420 MW.

Capacity on the Greece – Italy interconnection was allocated on a 50% - 50% basis between HTSO and TERNA for both directions. HTSO's part for imports to Greece (250 MW) was allocated in the form of physical transmission rights to 5 licensed generators and suppliers in one annual explicit auction at the price of 100 €/MW. There were 5 bidders in total and PPC obtained 57.2% of the auctioned capacity.

As regards the allocation of export capacity from Greece, RAE approved a proposal by HTSO for applying simultaneous allocation on all interconnections, in order to take into account security of supply requirements that affect total export capability of the Greek system, in addition to operational security constraints associated with physical congestion at interconnections.

Table 3.1: 2006 annual auction results for exports from the Greek system

Number of Bidders	Number of Capacity Assignees	Prices	Product
9	5	30.100,00 €/MW.period (equivalent to 5,86 €/MWh)	JAN, APR, MAY - DEC (All days – All hours) 5136 hours - 50 MW
	3	900,00 €/MW.period (equivalent to 0,48 €/MWh)	JAN - MAY & SEP - DEC Weekdays & Saturday (23:00 – 07:00) 1872 hours- 150 MW
	7	15.100,00 €/MW.period (equivalent to 11,95 €/MWh)	OCT – DEC Weekdays & Saturday (07:00 – 23:00) 1264 hours - 50 MW
	5	1.100,00 €/MW.period (equivalent to 1,18 €/MWh)	JAN - MAY & SEP - DEC Sundays – All hours 936 hours - 150 MW

In March 2006, HTSO begun D-2 allocation of additional physical transmission rights for export through explicit auctions, combined with week-ahead notification by capacity assignees of their intended use of annually allocated capacity.

3.1.2.3 Interconnection congestion management in 2007

A set of auctions rules for congestion management, common for all interconnections of the Greek system, was put in place starting January 2007. The main principles of congestion management according to these rules are as follows:

- Annual, Monthly and Day-Ahead (D-2) Explicit Auctions of Physical Transmission Rights
- Rights with obligation to nominate use before day-ahead auction
- UIOSI (reallocation by HTSO) and UIOLI at the time of firm nomination
- PTRs freely transferable between eligible bidders up to nomination deadline. Transactions notified to HTSO for checking transferee eligibility and grant approval.
- 100% compensation of PTR holders in case of non-scheduled curtailment

Under this scheme, HTSO manages congestion on the following interconnections and directions:

- Bulgaria – Greece: 50% of NTC
- FYROM – Greece: 100% of NTC (following agreement with FYROM TSO)
- Albania – Greece: 100% of NTC (following agreement with Albanian TSO)
- Exports from Greece through all interconnections above and the Greece – Italy cable: 100% of NTC.

Congestion on the Greece – Italy interconnection for the direction of imports to Greece from Italy is managed by the Italian TSO for the entire NTC, through annual and daily auctions, according to the same auction rules. On interconnections where congestion is managed entirely by HTSO (100% NTC), congestion revenue is split on an equal basis.

Due to uncertainties in availability of energy for imports primarily from Bulgaria since the beginning of 2007, no annual auction was organised for imports to Greece from the northern interconnections. Instead, NTC is estimated on monthly basis taking into account forecasted energy balances, and long term allocation of interconnection capacity is made through monthly auctions. At the day-ahead level, explicit auctions are held in order to reallocate long term rights that are not nominated.

Table 3.2: Monthly explicit auction results for imports to Greece – Northern Interconnections

Month	Border	Auctioned Capacity (MW)	Product Hours	Allocated Capacity (MW)	Clearing Price		Number of Bidders	Number of Assignees
					€/MWh	€/MW		
JAN	BG	135	528	135	0,20	105,6	6	5
	FYROM	160		160	0,15	79,2	6	3
	AL	70		70	0,05	26,4	3	2
FEB	BG	135	672	135	2,99	2.009,3	10	8
	FYROM	150		150	0,00	0,0	4	4
	AL	40		40	0,07	47,0	4	2
MAR	BG	163	743	163	14,13	10.498,6	13	4
		37	623	37	5,55	3.457,7	8	2

	FYROM	150	743	150	4,07	3.024,0	6	6
	AL	0						
APR	BG	90	720	90	5,10	3.672,0	11	6
		85	528	85	3,42	1.805,8	11	7
		50	408	50	2,58	1.052,6	11	4
		25	216	25	2,36	509,8	11	3
	FYROM	100	192	100	0,44	84,5	5	3
	AL	0						
MAY	BG	150	432	150	4,52	1.952,6	8	8
	FYROM	70		70	1,49	643,7	6	5
	AL	0						
JUN	BG	295	720	295	8,49	6.112,8	13	7
	FYROM	50	480	50	1,75	840,0	7	3
	AL	60	288	60	0,49	141,1	4	1

Capacity for exports from Greece is allocated simultaneously on all interconnections, taking into account supply security constraints that affect total export capability of the Greek system at several timeframes. Annual, monthly and daily auctions are held by the Hellenic TSO.

Table 3.3: Annual explicit auction results for exports – All interconnections

Month	Border	Auctioned Capacity	Total Export Capability	Product Definition	Product Hours	Allocated Capacity	Clearing Price		Number of Bidders	Number of Assignees
		MW				MW	€/MWh	€/MW		
JAN - FEB SEP - DEC	IT	500	250	LOW LOAD Period Weekdays & Saturday (22:00 - 06:00 CET) Sunday (00:00 – 24:00 CET)	1777	100	0,30	533,1	14	7
	BG	100				0			0	0
	FYROM	100				0			2	0
	AL	200				150	0,30	533,1	4	3
SEP - DEC	IT	500	100	HIGH LOAD Period Weekdays & Saturday (06:00-22:00 CET)	1664	100	15,51	25.808,6	16	8
	BG	100				0			0	0
	FYROM	100				0			1	0
	AL	200				0			2	0

Table 3.4: Monthly explicit auction results for exports – All interconnections

Month	Border	Auctioned Capacity	Total Export Capability	Product Definition	Product Hours	Allocated Capacity	Clearing Price & Auction Income		Number of Bidders	Number of Assignees
		MW				MW	€/MWh	€/MW		
APR	IT	500	150	1/4-8/4 & 14/4-16/4 22:00 – 06:00 CET	136	150	0,09	12,2	6	3
	BG	150				0			1	0
	FYROM	150				0			1	0
	AL	150				0			1	0
	IT	500	150	9/4-13/4 & 23/4-30/4 22:00 – 06:00 CET	120	150	0,09	10,8	6	2
	BG	150				0			1	0
	FYROM	0								
	AL	150				0			1	0
	IT	500	150	17/4-22/4 22:00 – 06:00 CET	64	150	0,09	5,8	7	3
	BG	150				0			1	0
	FYROM	150				0			1	0
	AL	0								
MAY	IT	500	150	1/5-6/5 & 20/5-27/5 22:00 – 06:00 CET	160	150	0,22	29,9	5	2
	BG	150				0			1	0
	FYROM	230				0			1	0
	AL	100				0			1	0
	IT	0	150	28/5-31/5 22:00 – 06:00 CET	32					
	BG	150				50	0,00	0,0	1	1
	FYROM	230				50	0,00	0,0	1	1
	AL	100				50	0,00	0,0	1	1
	IT	500	150	7/5-19/5 22:00 – 06:00 CET	120	150	0,14	9,0	5	3
	BG	0								
	FYROM	0								
	AL	0								

The relatively small amount of interconnection capacity that was allocated as long-term firm capacity was due to extraordinary circumstances (very low hydro reserves, LNG facility planned outage) impacting on supply security. In principle, additional interconnection capacity has been made available for exports, mostly during low load periods (22:00 – 06:00 CET) and Sundays.

3.1.2.4 Transmission System (internal) Congestion and Management

Due to uneven distribution of generation and demand between the northern and the southern areas of the country, parts of the national transmission system connecting these areas experience system constraints especially in periods of high demand. According to the provisions of the 2005 Grid Code, such constraints shall be integrated with the functioning of the daily energy wholesale market (by September 2007). In general, when the HTSO predicts that the unconstrained Day-Ahead schedule, as revealed by the unconstrained wholesale market, violates physical flows rules (mainly due to voltage stability limits, and secondary due to thermal limits) a solution will be determined that is constrained by physical transmission system limitations. In these cases, the market is split, two different zonal System Marginal Prices are calculated for generators, and one uniform SMP for suppliers is determined as the weighted average of the zonal generators' SMPs.

Additionally¸ and in order to avoid aggravating the North-South imbalance problem or even to mitigate its impact, long term signals are provided to prospective generators by means of a zonal "G" component of the TUoS tariff.

3.1.2.5 Provision of information by the TSO

Auction rules provide a list of information the TSO needs to publish with respect to interconnection congestion management. Published information consists of the following:

- Long term Total Transfer Capacity & Transmission Reliability Margin
- Scheduled maintenance period
- NTC and Available Transmission Capacity to be auctioned, taking into account nominations and resale notifications UIOSI)
- Auction results (Clearing Price, Bidders and Allocated Capacity per Bidder)
- Notification of PTR transfers between eligible participants
- Curtailments for scheduled maintenance and due to the occurrence of events and circumstances unforeseeable in the long term
- List of the Users who are eligible and registered as Bidders

As regards other information relevant to anticipating the situation of the national system regarding congestion (internal and on interconnections), HTSO currently provides the market with forecast (D-1) information regarding system demand, generation from renewable energy units and generation from Reliability-Must-Run hydro units. Information provided ex-post includes actual system demand and marginal price, actual unit production and actual flows on interconnections for the previous 15 days.

RAE issued in April 2007 a decision elaborating in more detail information publication requirements regarding wholesale market operation and cross-border congestion management, according to the general provisions of the Grid Code and in order to comply with Regulation 1228/2003. According to this decision, HTSO shall publish the following information:

Ex-ante information published daily

- Nominated Physical Transmission Rights
- Interconnection transmission capacity available for short-term allocation
- Detailed results of day-ahead capacity allocation auctions
- Forecasted hourly system load
- Forecasted hourly ancillary services requirements
- Forecasted transmission system constraints

- Forecasted production from Reliability-Must-Run hydro, priority dispatch renewable energy and cogeneration units and units under trial operation
- Load declarations
- Day Ahead Energy Schedule
- Forecasted hourly SMP
- Aggregate available generating capacity on the basis of submitted energy offers

Ex-post information published daily

- Deviations in system and market operation data from respective forecasts
- Ex-post Dispatch Schedule
- Ex-post SMP
- Actual generating unit operation
- Actual interconnection schedules and flows
- Actual generating unit availability
- Procured ancillary services

Other information published in longer periods

- Interconnections annual maintenance schedule, with continuous updates as necessary
- Transmission system annual maintenance schedule and, in addition, monthly announcement of the impact of significant scheduled transmission outages on system operation and transmission constraints
- Annual maintenance schedule of generating units, with continuous updates as necessary
- Long-term evolution of interconnection transmission capacity, on annual basis
- Forecasted available interconnection capacity on annual, monthly and weekly basis
- All information regarding the performance of capacity allocation auctions, as per the requirements detailed in the Auction Rules.

Other information published on occurrence

- Any modification in generating unit availability at the time of occurrence
- Significant non-scheduled transmission system outages, events and operations, both in the national grid and the grid of neighboring countries, and their impact on system operation and transmission constraints.

It is expected that HTSO will be in the position to fully comply with this decision by the end of 2007, by integrating these requirements in its market operation platform that is currently under development.

3.1.2.6 Integration of congestion management in wholesale market functioning

Regardless of possession of Physical Transmission Rights, the actual use of interconnections for imports and exports is ultimately subject to inclusion of the respective transactions in the Day Ahead Energy Schedule. Inclusion of these transactions in the DAES is based on their energy price offer, in the same way that offers from generators are included and scheduled. Entities that have been allocated transmission rights at an interconnection have priority over others with no rights, in case of equally priced energy offers when the interconnection is congested. Until July 1st 2007 however, only imports are scheduled at D-1 on the basis of their priced energy offer. Exports are scheduled on the basis of firm nominations submitted at D-2 (non-priced load declarations), and priority is given to transactions that are associated with allocated transmission rights.

According to the 2001 Grid Code, congestion revenue is accumulated under a separate account maintained by the Hellenic TSO (HTSO). HTSO may utilize this account for the sole purpose of improving and increasing interconnection capacity. The Ministerial Decree regarding allocation of interconnection capacity in force until 31.12.2006 explicitly stipulates that congestion revenues are maintained by the HTSO in a separate account provided by the 2001 Grid Code for the purpose of improving and increasing interconnection capacity. The new Grid Code, approved by Ministerial Decree in 2005, sets similar principles for the utilization of congestion revenues. Revenues accumulated during each year from interconnection capacity allocation is transferred at the end of the year to a dedicated reserve account maintained by the HTSO. The amount accumulated in this reserve account is used exclusively for the purpose of increasing interconnection capacity. Furthermore, the 2005 Grid Code envisages that expenditure from this account is made by decision of the Minister for Development following an opinion by RAE. It should be noted, however, that these provisions of the 2005 Grid Code become effective on the 1st of January 2008. Utilization of congestion income, as foreseen under the provisions of the current and the previous Grid Code is compatible with the use foreseen under Regulation EC/1228/2003 article 6, paragraph 6. It was recently brought to RAE's attention that the fiscal year 2006 profit and loss statement published by HTSO is not limited to the HTSO's annual budget as approved by the Minister for Development and intended to cover administrative and operating costs of the HTSO keeping in mind that HTSO is in fact an ISO with no transmission assets. In fact, it appears that the 2006 profit published by HTSO which is subject to taxation and distribution to stockholders -- the government and the Public Power Corporation -- includes revenues accumulated from interconnection capacity allocation in previous years. RAE is currently investigating the matter with the intention of taking appropriate action should it be determined that HTSO congestion revenues have been improperly allocated

3.1.3 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 and 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, a special department of PPC undertakes currently the responsibilities of the Distribution System Operator, which consequently will be transferred to the HTSO (along with the special unit of PPC), by July 1st, 2007. The Distribution System Operator, according to the provisions of the same Law, is responsible for ensuring the reliability, functionality and efficiency of the distribution network, and for third party access to the distribution network. The Distribution System

Operator is responsible for the distribution network that is interconnected with the mainland's transmission system.

The operator of the distribution network, i.e. PPC S.A. 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 (different department of PPC S.A.) is also the generation dispatcher.

RAE is responsible for monitoring the compliance of the network operators and the owner of the networks with the provisions of the Codes. With reference to the decision of the relevant rules, RAE gives a consenting opinion for the approval of the Codes by the Minister of Development, and decides on the details of the application of the Codes, as already mentioned. The following issues are covered (or should be covered since the Distribution Network Code has not been approved yet), by the network Codes:

- methodology for setting the network tariffs,
- performance measurement and quality regulation,
- provision of information by the network operators to the interested parties.

Network tariffs are approved annually by the Minister of Development, following a simple opinion by RAE.

The Distribution Network Code has not been approved yet. RAE is planning soon the relevant consultation procedure on the technical aspects of the Code, as well as on the quality regulation aspects. The Distribution Network Code is expected by RAE to be enforced by the end of 2007. Until then, PPC, as the distribution network owner and operator, follows internally defined rules and procedures.

3.1.3.1 Transmission Network Tariffs

Network tariffs are calculated on the basis of the annual system cost, which is defined as the sum of the annual barter owed by the HTSO to PPC SA (i.e. the sum of the annual depreciation of the assets of the Transmission System, its operational and maintenance expenses and the return on the non-depreciated capital of the Transmission System, with the rate of return being approved by RAE) and the annual cost of any works for the expansion of the System. The annual system cost is adjusted to also take into account the differences between the forecasted and realized transmission expenses during the previous year.

The 2005 Grid and Market Operation Code prescribes that the Transmission System charges are allocated to generation -including imports- (G) and load –including exports- (L) according to a 15% - 85% split. Both G and L components are based only on the capacity of the corresponding user. The L component is uniform throughout Greece, while G has a zonal variation, according to the location of each generator. The 2005 Code provides for two zones, namely (a) Attiki-Viotia, where G is zero, and (b) the rest of the interconnected system.

The operating expenses of the HTSO are not covered by the Transmission Network Tariffs. The annual budget of the HTSO, as approved by the Minister of Development, following an opinion by RAE, is debited in a regulated account which forms part of the Uplift Account. The Uplift Account is also used for the coverage of the cost of the ancillary services and for resolving system constraints. To balance the Uplift Account, a charge is imposed to all suppliers and self-supplied eligible customers in proportion to their share in total consumption.

A more detailed description of the methodology and procedures used for the definition of the Transmission Network Tariffs is provided in Annex I.

The role of RAE in the procedure of the definition of the Transmission Network Tariffs is mainly advisory. The final approval of the tariffs is performed by the Minister of Development, following a simple opinion of RAE. According to the Grid Code, RAE gives its opinion for the annual cost of the System, including the annual barter owed by HTSO to PPC SA and the annual operating cost of the System, and also the calculation of the use of the system charges, as performed by the HTSO.

3.1.3.2 Distribution Network Tariffs

Legal unbundling of the operation of the distribution network has not yet been established. Also, due to lack of the Distribution Network Code there is neither a methodology nor a procedure for the approval of the distribution system charges. Such charges are assumed to be incorporated into the retail tariffs of PPC, which are approved by the Minister of Development, following the opinion of RAE.

A set of charges for the use of the medium voltage distribution network were approved in April 2002 by the Minister of Development, following the opinion of RAE, to facilitate the opening of the market to eligible customers connected to this network. Due to the absence of adequate accounts unbundling, RAE performed the relevant calculations on the basis of best estimates. RAE, taking into account the progress achieved in 2005 – 2006 with the unbundling of the accounts of PPC, will formulate its opinion for the distribution network charges to be approved by the Minister of Development, based on the methodology applied for the Transmission System Charges.

3.1.3.3 Estimated national average network charges

According to the network tariffs for 2006, as approved by the Minister of Development after the opinion of RAE, the TUoS charges for Suppliers is set to €20.335 MW/Year, for generators in southern Greece €514MW/Year and for generators in northern Greece €6.900 MW/Year.

According to RAE’s calculations, the average cost of transmission system use was 4,65 €/ MWh, based on the total energy consumption on the Interconnected Transmission System in 2005. Given the 15%-85% G – L split, this cost led to an average G charge of 0,70 €/ MWh. The corresponding average L charge was 3,95 €/ MW/h..

For the Distribution Network, no tariff or estimation by RAE exists for low voltage distribution network charges. Supply to low voltage eligible customers is practically not possible, due to the absence of the Distribution Network Code and interval metering or other method for settlement of consumption by the DSO (PPC SA).

Moreover, since the unbundling of PPC accounts has not yet been completed, the end-user tariffs are still bundled, providing only a unified charge including energy, transmission, distribution, PSO and metering charge. Estimates of average network charges for typical consumers can only be given as regards transmission system use tariffs. For a typical consumer of the Ib category transmission charge is calculated to €1.016,75 per year or 20,35 €/MWh, and for the Ig category to €81.344 per year, or 3,38 €/MWh. It has to be noted that since the transmission charges are only capacity related, in some consumers’ categories, especially those with very low load factor, the reported charge per MWh seems to be very high.

For a typical medium voltage industrial customer (Ig): Annual transmission & distribution network charges = € 81.340 (transmission charges) + € 116.300 (distribution charges, estimated on the basis of Medium Voltage Distribution Network Tariffs proposed by RAE for 2002, adopted by decision of the Minister of Development –assuming that the subscribed demand is utilised fully for 11 months and

50% during the 12th month) = € 197.640 p.a. As said, the distribution charges remain on the levels set by the decision of 2002.

3.1.3.4 Network performance and quality of service regulation

As regards the Transmission System, operating standards and HTSO obligations for securing and monitoring network performance following the UCTE rules are foreseen in the Grid Code. However specific procedures, indicators etc, for quality of service regulation are not stipulated, since it is rare for power quality on the Transmission System to become a ruling factor on service quality of downstream distribution networks and their customers. Such regulation falls under the general authorities vested in the Regulator, with respect to monitoring and assessing the performance of HTSO in carrying out system and market operation.

Network performance and quality of service standards and obligations have not yet been set for the Distribution System Operator, due to the lack of the Distribution Network Code, which is currently under preparation.

Under the existing legislation, there is no procedure for the formal evaluation of the quality of service offered either by the Transmission or the Distribution system operators.

3.1.3.5 User Connection to the Network and Publication of Data

Regarding user connection to the Transmission System, the Grid Code and the License of the HTSO provide that the HTSO publishes the General Terms and Conditions for connection to the Transmission System, which can be summarized as follows:

- Procedures for applying for a new connection to the Transmission System
- Overall criteria used by HTSO in selecting the suitable method of connection
- General description of connection works and associated equipment – Standards and specifications for connection works and equipment
- Typical connection examples
- Indication of budget connection costs (list of unit cost estimates for engineering/ equipment/works)
- Document specimens (connection application, connection contract)

In 2007 RAE granted its opinion to the Minister of Development for the adoption of the General Terms and Conditions for Connection to the Transmission System, based on HTSO proposal. This document will come into force by decision of the Minister of Development.

There are no legal obligations to the DSO for the publication of data, since neither the Distribution Network Code nor the terms for the Licence of the DSO are available.

3.1.3.6 Balancing arrangements

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. This concept was not altered by the 2005 Grid and Market Operation Code, since it was considered that the current stage of development of the electricity market in Greece, 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.

The administrative balancing arrangements are closely linked to the operation of the mandatory Day Ahead Market, which, especially following the improvements introduced by the 2005 Grid and Market Operation Code, has been designed with the view to facilitate the needs of new entrants and small market participants.

A detailed, albeit concise, description of the provisions of the 2005 Grid and Market Operation Code concerning the wholesale market, including detailed description of the settlement of imbalances, is presented in Annex II.

Indicators for balancing arrangements

According to the provisions of the 2005 Grid and Market Operation Code, the entire Interconnected System constitutes a single balancing area. The Code virtually provides for economic separation between the zones of the System with generation deficit and surplus in cases of relevant system constraints, by differentiating both the Day Ahead Market Price and the Imbalance Settlement Clearing Price that generators are paid, whenever the Day Ahead merit order deviates from the economic merit order due to such System constraints. The Balancing interval is set to 60 minutes.

Gate closure for all nominations is set to 12:00 a.m. of the day preceding the Dispatch Day. Nominations can be submitted the earliest 48 hours prior to gate closure.

Intra-day trading is not foreseen. Since 1.7.06, nominations submitted to the Day Ahead Market can be revised up to 5 times prior to gate closure. Revisions are not allowed following gate closure.

Provision of information

The HTSO must provide to market participants the following information regarding the balancing mechanism;

According to the 2001 Grid Code, on the day before the Dispatch Day, HTSO provides participants with the following information regarding the Dispatch Day:

- Forecasted Hourly System Load
- Net and Available Transfer Capacity on interconnectors
- Information regarding Transmission System status & availability (scheduled operations and maintenance on transmission infrastructure, equipment outages, significant events, system alarms and emergency conditions)
- Day Ahead Dispatch Schedule for each generator (and changes thereof prior to the Dispatch Day) and Forecasted Hourly System Marginal Price.
- Changes in the Day Ahead Dispatch Schedule during the Dispatch Day due to congestion and system constraints.

HTSO also publishes daily on its Web Site the updated information regarding the Transmission System Loss Factors and the Maintenance schedule for the Transmission System and the Interconnectors.

In due course of the Dispatch Day, the HTSO provides market participants with the following information:

- Actual Hourly System Load.
- Hourly Ex-post System Marginal Price (market clearing price).

- Information regarding the actual operation of the system at least on a weekly basis.
- Information regarding the actual dispatch of each unit, for the previous 15 days.

According to the 2005 Grid Code, HTSO must provide participants with the following information:

- Weekly schedule of Reliability-Must-Run hydro units (ex-ante) and actual dispatch program (ex-post)
- Net and Available Transmission Capacity on interconnectors
- Information regarding Transmission System status & availability (scheduled operations and maintenance on transmission infrastructure, equipment outages, significant events, system alarms and emergency conditions)
- Forecast of the Hourly System Load, the Ancillary Services Requirements and the Transmission System Status (forecast regarding onset of congestion and/or constraints)
- Bids submitted by HTSO regarding injection of energy from units under priority dispatch regime (renewable & cogeneration, units under trial operation)
- Ex-post data concerning the previous dispatch day and particularly as regards forecast deviations from actual system operation
- Computed System Marginal Price, total System Load, Imports – Exports Schedule accepted in the Day Ahead Market.
- Provisional Dispatch Schedule for generators and suppliers, as it is accepted in the Day Ahead Market.
- Ex-post statistical information regarding the operation of the Day Ahead Market

HTSO must also publish any updated information regarding the Transmission System Loss Factors, historical data and statistics regarding the accuracy of its forecasts and the Scheduled Outages of the Interconnections.

In the context of Dispatch Scheduling, HTSO must also provide to participants a report on any system constraints that were taken into consideration and affected the solution of the Dispatch Schedule problem.

In the context of Imbalance Settlement, HTSO must publish the Imbalance Marginal Price and keep relevant records available to participants for a period of 5 years.

3.1.4 Effective unbundling

3.1.4.1 Transmission and Distribution System Operators

A separate company, the “Hellenic Transmission System Operator” S.A. (“DESMIE” or HTSO, www.desmie.gr), established by Ministerial Decree 328/12.12.2000 is the Transmission System Operator responsible for the operation and exploitation of the Transmission network and for ensuring its maintenance and development (article 14 of Law 2773/1999). Nevertheless, PPC SA is the owner of the Transmission System according to Article 12 of Law 2773/1999. The HTSO is 51% state owned and 49% owned by PPC, according to Article 16 of Law 2773/199 as amended by Law 3426/2005.

The headcount of the HTSO is currently 200 employees, while a total 320 employees are expected to staff the HTSO according to its organizational chart. Nevertheless, most of the employees of the

HTSO come from PPC, and are members of PPC's trade union. According to the new Law 3426/2005, PPC's staff seconded to the HTSO is under the obligation to choose, approximately by the end of 2006, either to be return to PPC or to remain with HTSO by resigning from PPC. It has to be noted that PPC occupies 1700 employees in the Transmission Network business. All maintenance and expansion works, decided and planned by the HTSO, are executed by PPC staff.

The HTSO is located separately from PPC in its own premises and uses own corporate logo and web site.

To safeguard the independence of the HTSO, the members of the board of directors should not be related in any way to a generation or a supply company, while PPC appoints up to two members of the board.

As far as the DSO is concerned, under law 3426/2005, article 12, PPC had the task to set up, not later than 22 June 2006, within its organizational structure a unit that will be assigned all responsibilities of the distribution network operator outlined below. This unit will be transferred to the HTSO by 1 July 2007, and the HTSO will be assigned not later than 1 July, 2007 with the additional role of the Distribution Network Operator.

PPC will retain ownership of the (distribution) Network and per Article 11 of Law 3426/2005 will continue to receive applications for connection to the network, run the network, ensure the technical integrity of the network, develop and maintain the network according to the plan developed by the DSO. In general, the HTSO will be responsible for monitoring the activities of the owner of the distribution networks connected to the transmission system of the mainland. The distribution network of the non-interconnected islands will be operated by a separate department of PPC ("Non-interconnected islands operator"), which will also be responsible for the dispatching of the generating units..The responsibilities of the HTSO regarding the distribution system connected to the mainland transmission system, will be to safeguard the:

- Security of network
- Technical soundness and economic efficiency of network
- Quality of voltage and supply reliability
- Access to network
- Connection to network
- Metering system and metering
- Flow of Information to network users
- Cooperation with the airport operator
- Contracting with the network owner (PPC) for the development of the network

The number of employees that will be working in the DSO is not known as yet, but preliminary estimates count for about 100 employees needed to undertake these tasks. These employees will be probably transferred from PPC to the HTSO-DSO, in a similar way with the first group of employees of the HTSO for the Transmission System Operations. It is noted that more than 8200 employees are occupied in PPC's distribution network business, and these personnel will be serving all new connections and maintenance and expansion works, as planned by PPC.

As far as the unbundling of the accounts of the HTSO are concerned, all costs of the legally unbundled HTSO reflect its administrative costs and, therefore, are not shared with any other affiliated companies of the owner of the Transmission System, i.e. PPC SA.

Moreover, although the legal unbundling of the Distribution System has not been completed yet, the cost of the DSO will only reflect its administrative costs, in the same manner as for the HTSO.

Nevertheless, the accounts of the transmission and distribution businesses within PPC should be audited by the certified accountant responsible for the auditing of PPC according to the provisions of article 30 of Law 3426/2005.

In case of failure to comply with the provisions of Law 2773/1999, or with secondary legislation issued as specified in the Law 2773/1999, RAE can impose fines pursuant to article 33 of Law 2773/1999.

3.1.4.2 Unbundling of accounts

As mentioned in last years´report, article 30 of Law 2773/1999, laid down that the rules for the allocation of assets, liabilities, expenditure and income which should be implemented for the compilation of the separate accounts by vertically integrated undertakings should be specified in the annex of the annual accounts of the undertakings, and these rules can only be modified following RAE's approval. The wording of the abovementioned provision which provided that RAE is responsible for approving any modification to these rules, lead to long period of dispute between RAE and PPC, concerning the competences of RAE to approve not only the modifications but also the development of the methodology, was amended by Law 3426/2005, which clearly assigns to the RAE the authority to co-operate and approve the methodology used for the unbundling of accounts of vertically integrated undertakings.

PPC S.A. has already submitted unbundled accounts up to year 2005 and work is currently underway, in order to have an updated full set of unbundled accounts up to year 2006. Thus, and in view of the assessment of the accounts submitted by PPC, RAE had to approve again the the principles, the set of rules and the methodology, according to which the vertically integrated company PPC S.A. would submit its unbundled accounts. Finally, and after a consultation period of approximately three months, RAE approved the aforementioned principles rules and methodology with its decision no. 86/2007.

3.2 Competition Issues [Article 23(8) and 23(1)(h)]

The development of a liberalized electricity market in Greece suffered a significant delay due to ineffective market design adopted by Law 2773/1999, harmonizing the national legislation with Directive 96/92/EC.

Although the new (2005) Grid and Market Operation Code provides the legal framework for the development of a competitive electricity market, with the exception of renewables and small CHP which enjoy a special regime through PPAs (feed-in tariffs and investment support), the interest by potential investors has been restrained due to the existence of a dominant company in both the generation and supply businesses, and the low System Marginal Prices recorded in the Day-Ahead market.

There are currently two independent power plants not owned by PPC SA in the interconnected (one natural gas peaking unit of 150 MW under contract with the HTSO and one 400 MW CCGT unit belonging to the partially state owned Hellenic Petroleum SA).

However, it should be noted that interest for the wholesale electricity market by private investors looks more positive than previous years. Three private industrial groups have announced their intention to install GTCC units of total capacity in the order of 1200 MW before the end of the decade. Furthermore, interest for developing coal plants has been registered: three applications for generation license concerning approximately 1600 MW of total capacity have been submitted to the Regulator.

Competition regarding the retail market was limited mainly to imports. However, the capacity of the northern interconnections of the Greek Transmission System is limited, compared to the size of the market. Additionally, and since the structure and level of the retail tariffs are of ultimate importance for the efficiency and competitiveness of the market, RAE is currently undertaking a study for estimating the long run marginal costs of generation, transmission and distribution of electricity in Greece. The main objectives are that all economic costs are fully reflected in the high, medium and low voltage sectors as well as to perform an evaluation of the existing tariff structure and development of consumer categories, based on their load profiles, their voltage connection level and their technical and behavioral characteristics.

3.2.1 Description of the wholesale market

The wholesale electricity market operated in 2006 according to the provisions of the 2005 Grid and Market Operation Code. This Code establishes a wholesale electricity market of the mandatory pool type (see Annex II for a brief description). Bids submitted by generators should be less or equal to the respective short-run marginal cost, and a uniform upper limit of 150 €/MWh of the bids and of the SMP applies. All transactions are settled after the day, and all ancillary and balancing services are included, since there is no separate market for these services. From the daily market the generators receive the System Marginal Price 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.

In 2006 total consumption of **54,6** TWh (including losses) and a load peak of **9.961** MW have been measured in the interconnected System, which refers to the mainland of Greece (interconnected islands not included). The fuel mix for 2006 is shown in the following table.

Table 3.5: Fuel mix in the mainland system (2006)

PLANT TYPE	GWh produced	%
Thermal – brown coal (LIGNITE)	29165.2	53.43%
Thermal – gas	10169.1	18.63%
Thermal – oil	3309.1	6.06%
Hydro – storage (includes pumping)	6229.4	11.41%
Other renewables	1511.7	2.77%
NET IMPORTS	4202.4	7.70%
TOTAL	**54586.9**	**100%**

In 31.12.2006 the total maximum net generation capacity on the mainland's interconnected system was 11.653,8 MW, distributed as follows:

Table 3.6: Installed capacity in the mainland system (as of 31.12.2006)

PLANT TYPE	installed capacity (gross) in MW	installed capacity (net) in MW
lignite	5288.0	4,808.1
HFO	750	718
GTCC	2015.3	1,962.1
natural gas - other	507.8	486.8
hydro plants	3,016.5	3,016.5
RES and small cogeneration	660.3	660.3
Other cogeneration	108	108

As shown in the following table regarding the interconnected mainland's system, PPC owns about 95.3% of the installed capacity of 'dispatchable' units *(lignite, n.gas, oil and large-hydro)*. The competitors (T-Power, IRON THERMOILECTRIKI, RES-CHP-autoproducers) the remaining 4.7%.

Table 3.7: Total installed capacity and dominant utility´s market share.

Year	Total installed capacity - 'dispatchable' units (MW)	PPC market share
2003	10.649,5	100%
2004	10.797,3	98,6%
2005	10.797,3	98,6%
2006	11.577,6	95,3%

Table 3.8: Thermal generating capacity owned by IPPs:

Company	Capacity (MW)	Year of commissioning
T-Power S.A.	390	2005
IRON S.A.	148	2004

From the above it is concluded that the proportion of installed capacity owned by the **largest three** companies exceeds 99%.

During 2006 (total inland generation 50.384 GWh): lignite units had a share of 58,43%, Oil units 6,53%, GTCC units 14,27%, hydros 12,39%, T-Power 3,17% (IPP), other N.gas 2,94%, RES (2,24%) and 0,04% from IRON (IPP).

The above mentioned market share of PPC S.A. in terms of generating capacity in the mainland (interconnected) system, the HHI index is estimated to the upper bound of 10,000.

<u>The market for ancillary services:</u>

For the reporting period, and until full implementation of the 2005 Grid and Market Operation Code, ancillary services are assumed to be provided by all dispatched generators, on a pro-rata basis.

<u>The volume of electricity traded:</u>

As already mentioned, the wholesale market is organised as a mandatory pool. Thus all electricity produced/consumed is traded through the pool. There are not yet any standardised power exchange products, nor any organised forward market. Bilateral contracts between generating companies and supply companies are of course possible.

<u>Demand-side participation in the wholesale market:</u>

There is no formal demand side participation in the wholesale market in Greece. Demand´s involvement to the market is minimal and can only be effected indirectly, through the minimization of the use of electricity by a limited number of industrial customers during the peak hours, when the price of electricity is high. Nevertheless, these measures do reveal any some elasticity of the consumers to the high prices during peak hours, but in general are more considered as adequacy-of-supply measures.

<u>Integration with neighbour member-states:</u>

The relevant electricity market for Greece is the national market, since the interconnection capacity with neighbouring member states (namely Italy) is limited. Nevertheless, a number of traders, apart from PPC, are active in the region and supply energy in Greece, bought in the Balkans area. The price differentiation between the Balkans area (estimate of 39 €/MWh) and Greece (wholesale price from the daily market is around 52€/MWh, but the full energy price, based on PPC tariffs, is estimated on average base 55 €/MWh) and Italy (above 65 €/MWh) creates favorable conditions for electricity trading. Nevertheless, trading arrangements over the interconnections were not sufficient to enhance trading activity during 2005.

<u>Mergers and aquisitions:</u>

There is no activity related to mergers and acquisition, since most of the independent companies participating in the electricity market are in the very beginning of their development and the market is still very concentrated.

3.2.2 Description of the retail market

For 2006, the situation concerning the retail supply market to end-users for the interconnected system is shown in the following table.

Table 3.9: electricity consumption in the interconnected system – 2006

Voltage level	**Supply by PPC S.A.**										**Other suppliers**	**TOTAL**
	Resid-ential	Indu-strial	Com-mercial	Agri-culture		Public sector	Tra-ction	Mines & pumping	HV losses	MV, LV losses		
Low	15923,7	1316,2	9410,6	2025,7	703,4	758,8	0	**n.a.**	**n.a.**	2670,2	0	32808,8
Medium	0	5634,2	3245,1	361,6	0	879	138,8	**n.a.**	**n.a.**	339,6	157,7	10755,9
High	0	7775,5	0	0	0	0	0	1658,2	1265,1	**n.a.**	264	10699,1
Total	**15923,7**	**14725,9**	**12655,7**	**2387,3**	**703,4**	**1637,8**	**138,8**	**1658,2**	**1265,1**	**3009,8**	**421,7**	**54263,8**

As already mentioned (par. 2.2.1) PPC S.A. enjoyed a market of over 99,5% of the supply market. Total electricity consumption in Greece in 2006 was 54,3 TWh, of which 1,26 TWh were transmission system losses.

Practically, all consumers connected to the low voltage system are supplied by PPC. A number of eligible industrial consumers, connected to the MV or HV network, have been supplied with electricity from the interconnections either as self-supplied customers or through independent suppliers. The electricity volume transacted outside PPC is around 0.84% of the total electricity volume consumed in 2006

Since over 99% of the energy sold to the consumers is supplied by PPC, regulated retail tariffs are applied. During 2006, and since the unbundling of PPC accounts was not completed, PPC retail tariffs remain bundled, without explicit reference to energy, transmission, distribution and other costs. It is only the levy for RES that appears separately on PPC's bills and VAT (9%).

Up to today, supply authorization has been granted to 24 companies. None of these companies are affiliated to the HTSO or DSO businesses. It should be mentioned that most suppliers are active in trading than real supply. The licensed suppliers are the following:

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. TCB SA
21. ITA ENERGY TRADE LTD.
22. ELECTRICITY TRADING COMPANY HELLAS SA
23. EHOL HELLAS SA
24. EZPADA S.R.O.

3.2.2.1 Customers' switching of supplier

In 2006, 421.7 GWh were supplied by suppliers other than PPC S.A. (157.7 GWh in MV and 264 GWh in HV).

Issues related to the procedure of customers switching of suppliers are regulated by the 2005 Grid and Market Operation Code. Nevertheless, the absence of the Distribution Code that will regulate in detail the switching procedure for medium and low voltage customers, lead RAE to develop a Handbook for the management of metering and the periodic reconciliation between Suppliers serving customers connected to the distribution network. Provisions of this Handbook arrange the customer switching procedure until the enforcement of the Distribution Code.

In this context, RAE decided on the distribution network losses factors which are required to calculate the volume of energy supplied by independent suppliers. Nevertheless, distribution system charges have not yet been approved due to the lack of accounting unbundling between the activities of PPC and especially the lack of information on the cost of medium and low voltage networks. Based on an older (2002) RAE's decision on the cost of the MV network, customer switching is practically possible for the MV customers but not for the LV customers.

Article 9 of the Supply Code (Official Gazette B' 270/2001) provides that following the conclusion of a supply contract between an eligible customer and a supplier, the latter notifies the HTSO, submitting in addition an authorisation by the eligible customer which enables the HTSO to register the corresponding entry in the Trading Arrangements Registry, update the registry records relevant to the representation of the eligible customer's meter so as to reflect the modified status of supply, and notify the suppliers affected by the modifications.

Eligible customers may be supplied simultaneously by more than one supplier. In this case an agreement needs to be executed between the suppliers, defining the allocation rules among the suppliers of the supplied energy. The HTSO ensures that the entire metered energy consumption is fully allocated to the suppliers and/or the eligible customer.

The procedures followed by the HTSO with respect to supplier switching, 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 dealt with in more detail in the 2005 Grid and Market Operation Code where provisions exist for further elaboration by the HTSO in the Metering Handbook. These provisions came into effect on 1st of October, 2005.

Table 3.10 summarizes the concentration of the Greek electricity retail market.

Table 3.10: Development of the retail electricity market

	Total consumption (TWh)	No. of companies with >5% retail market	Number of fully independent suppliers (1)	Market share of three largest companies			Cumulative % customers having changed suppler (by volume)		
				large and very large industrial	small-medium industrial and business	very small business and household	large and very large industrial	small-medium industrial and business	very small business and household
2001	45,9	1	0	100	100	100			
2002	46,9	1	0	100	100	100			
2003	49,7	1	4	99	100	100	0,65%	0,016%	0
2004	50,9	1	10	98	99	100	1,55%	0,780%	0
2005	52,0	1	14	82 (2)	99,5	100	18% (2)	0,50%	0

(1) i.e. fully independent from network companies

(2) refers to high voltage connected self-supplied customers

3.2.2.2 Retail Price Levels

According to the provisions of the Supply Code in force, all retail supply tariffs of a company which covers more than 70% of the energy supplied to Eligible customers are regulated.

Currently, the average level of the (all inclusive) regulated PPC tariff ranges from 0,05 €/kWh for high voltage industrial customers to 0,08 €/kWh for medium voltage commercial customers and 0,12 €/kWh for low voltage commercial customers. Since 2002 only increases due to inflation have been approved, amounting to around 11,35%.). For the 2006-2007 period, increase was about 1% above the recorded inflation level.

Since no unbundling of the accounts of PPC has been approved, yet, it is not possible to present in detail all components of the aforementioned retail prices, such as network costs, levies included in network costs, energy cost plus supply margin and taxes (only the RES levy and VAT are shown separately).

As already mentioned before, RAE is currently undertaking a study for estimating the long run marginal costs of generation, transmission and distribution of electricity in Greece. The main objectives are that all economic costs are fully reflected in the high, medium and low voltage sectors, to perform an evaluation of the existing tariff structure and definition and analysis of various consumer categories, based on their load profiles, voltage connection level as well as technical and behavioral characteristics.

3.2.3 Measures to avoid abuses of dominance

According to the provisions of the Supply Code in force, suppliers are obliged to publish information regarding the structure of applicable tariffs, the charges applicable and the principles governing calculation of such charges, and the terms governing the supply contracts with customers. The Code also includes the general terms of supply contracts, while no special term may be contractually agreed in contradiction to such general terms. Further to that, the same Code provides for specific obligations regarding supply offers and contracts between big suppliers (i.e. suppliers with a market share of more than 40% of the total electricity consumed by Eligible customers in Greece) and Eligible customers. Such obligations refer to the exclusion of liability limitations. Finally, the Code includes special provisions for dominant suppliers with a market share higher than 70% of the total electricity consumed by Eligible customers in Greece. However, all these requirements have been proven of very limited practical importance for the Greek electricity market, since the failure of the previous market arrangements to promote the entry of independent power producers other than the incumbent, the limited interconnectors' capacity as well as the absence of the Distribution Network Code obstructed also the development of competition on the supply side.

As far as provision of information is concerned, the Grid Code includes provisions for a number of reporting requirements by the generators, related to the availability of the generating units and unplanned outages. However, the information provided by the generators has little effect in the wholesale market, at least as far as the bidding behaviour of the generators is concerned, since it is only used by the HTSO for the physical balancing of the transmission system. The same accounts for the suppliers, whose contracts with the end costumers are not linked with the System marginal price.

The 2005 Grid Code provides a number of additional procedures in order to prevent market abuse and protect the integrity of the market and strengthen the public confidence in the electricity market.

In particular , according to the 2005 Grid Code, a number of reports and declarations have to be submitted by the participants and especially the generators to the Market Operator (i.e. the HTSO), in order to be eligible to participate in the day-ahead energy market.

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. According to this declaration certain compensation items are calculated in the balancing mechanism, if the generating unit offers some services during the day. The techno-economic declaration is compulsory, and there is a penalty clause for non or false submission of the declaration. The HTSO is responsible for collecting the penalty, the level of which is decided by the HTSO after RAE's approval.

Generation license holders are obliged to submit for each generating unit they own declaration of partial or total non availability due to technical reasons, as well as declaration of major outages, that is unavailability for more than 10 continuous days during the summer period and 3 continuous months the rest of the year. The availability declaration is compulsory, and there is a penalty clause for non- or false submission of the declaration. The HTSO is responsible for collecting the penalty, the level of which is decided by the HTSO after RAE's approval.

All the information related to the availability of a generating unit is considered as "significant incident" and the HTSO is obliged to publish all incidents, protecting nevertheless the confidentiality of the information related to each participant.

Under the 2005 Grid Code, the organization responsible for market supervision is the Market Operator (HTSO). In parallel, RAE has the general responsibility to monitor the development of the electricity market and the market behaviour of all participants. RAE has the authority to ask any participant to submit to RAE published or confidential information, as RAE may require, in order to investigate actions and practices followed by the participants. In case of violation of the provisions of the 2005

Grid 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 the license.

RAE has issued special decisions regarding application details of the Codes, with the view to facilitate the competitive position of new entrants and enhance the security of supply of the electricity system. More specifically, Suppliers having obtained long term import rights have, according to the Codes (monthly use-it-or-loose-it mechanism), specific obligations to exercise these rights, otherwise they should declare their intention not to use part of their allocated capacity, which would then be available for short-term allocation and, most probably, would be allocated to PPC. RAE relaxed some of these obligations, when security of supply problems were not pressing.

4 Regulation and Performance of the Natural Gas market

4.1 Regulatory Issues [Article 25(1)]

4.1.1 General

4.1.1.1 Market structure

Following the implementation of law 3428/2005, one of the key developments was the establishment of the Hellenic Gas Transmission System Operator (HGTSO) in February 2007, under the name "DESFA". The new company is a 100% subsidiary of DEPA the incumbent gas company in Greece. DESFA 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 Revythousa island.

There where no major developments regarding the supply of natural gas. The incumbent company DEPA remains the only gas importer and supplier of large customers (consumption over 9 Gm3/year), power producers and of the local distribution companies (EPA). In distribution the three EPAs companies (which operate in the areas of Attica, Thessaloniki and Thessaly), remain the only suppliers of domestic, commercial and industrial customers in their areas of operation.

4.1.1.2 Market Opening

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 three years at the latest after the expiry of the derogation period (i.e. November 2009), subject to the milestones set therein. In addition, existing concessions in Greece have been exempted from certain provisions of the Gas Directive, including the eligibility rights of their customers, for the whole duration of the concession (article 28.4 of the Gas Directive).

According to the provisions of the Gas Law the market opening milestones are as follows:

1. Currently, 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 Mm3/year.
2. As of 15.11.2008 eligible customers will be:
    a. Non-household customers located outside the geographic areas served by regional gas distribution companies under a concession regime (EPAs), irrespective of their annual consumption.
    b. Non-household customers located in the EPA areas, purchasing natural gas for final use in vehicle motors in the form of Compressed Natural Gas.

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

d. 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 said contracts, existing EPAs will have the right to choose their supplier for the whole of the natural gas quantities they purchase.

3. Finally, as of 15.11.2009, eligible customers will be household customers not located in the geographic areas of the three EPA companies or the geographic area of any newly formed EPA that will be granted a derogation, pursuant to articles 28(4) and (5) of Directive 2003/55/EC.
4. As of the expiry of existing concession licenses (ca 2030) for the EPAs of Attica, Thessaly and Thessaloniki, all the customers of those EPAs will also be eligible to choose their supplier.
5. All EPAs which will be formed after the entry into force of the Gas Law will also be eligible customers by the date of their incorporation.

Currently, eligible customers represent approximately 69.8% of the total gas demand in Greece, based on the actual 2006 demand data.

The estimated market opening by the end of 2008 and 2009 is in the order of 80% of the total gas demand.

4.1.2 Management and allocation of interconnection capacity and mechanisms to deal with congestion

Currently, the Greek NGS is only interconnected with the Bulgarian transmission system in the northern border of the country. 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 the implementation of a TPA regime which applies to the rest of Bulgarian national network. This is also the case for the transit pipelines upstream of Bulgaria.

The new interconnection with Turkey is expected to be operational by the end of 2007. Therefore, the Greek NGS so far is commercially isolated from the neighbouring TSO regions. For information on planned interconnections please see section 5.2.3 below.

There is no physical (or contractual) congestion experienced in the NGS, either nationally or on the interconnection points, since the total capacity of the Greek Natural Gas Transmission System is estimated at around 6.5 to 7 billion cubic meters per annum, while the existing market size is approximately 3.0 Gm3/year.

According to the provisions of the Gas Law, the Network Code will include all necessary congestion management and capacity allocation rules, in accordance with the provisions of both the Gas Directive and the Gas Regulation. RAE is entrusted has been assigned the responsibility of monitoring and supervising the actual application of such rules, in cooperation with the Regulators of the region.

For the time being there is no gas transit through Greece.

4.1.3 The regulation of the tasks of transmission and distribution companies

4.1.3.1 Network Tariffs

A. TPA tariffs

There were no changes regarding tariffs for TPA to the Transmission System and the LNG Terminal. TPA tariffs to the NNGS (Transmission System and LNG Terminal) are set in the Ministerial Decision 4955/2006, until the elaboration of the Tariff Regulation.

The Tariff Regulation will set according to the provisions of law 3428/2005, the tariff methodology for TPA to both the transmission system and the LNG terminal, The regulation will be drafted by RAE, following a recommendation by the HGTSO and a public consultation. Actual tariffs will be set on the basis of the Tariff Regulation by the HGTSO and will be approved by RAE. Both the Tariff Regulation and the actual tariffs will be submitted by RAE to the Ministry of Development for formal approval.

According the Ministerial Decision 4955/2006 (Government Gazette B 360/27.3.2006), TPA tariffs are set by the system operator and approved by the Minister of Development, after RAE expresses an opinion. The methodology for the calculation of tariffs is based on rate-of-return regulation. For each year over a certain period, the annual required revenue of the HGTSO is calculated taking into account both capital and operating expenses. The Weighted Average Cost of Capital (WACC) used in the calculation of capital expenses is 10,06% nominal pre-tax or 6,56% real pre-tax. Due to the considerable uncertainty regarding the utilization of the Revithoussa LNG terminal over the next few years (for balancing and/or TPA purposes) a provisions has been made to recover 95% of the required revenue for LNG terminal, through the transmission tariff applied for natural gas transportation via the high pressure pipeline running through mainland Greece and only the remaining 5% is recovered from the LNG tariff. In a largely underutilised facility with high capital costs, this was considered necessary for the initial stage of the market opening, in order to reduce the access charges and thus to provide incentives for the increased utilization of the terminal.

The unit tariff for both the transmission system and LNG terminal use is derived by dividing the required revenue by the projected volumes which are expected to be transported through the transmission system or regasified in the LNG terminal respectively. The unit tariff is split in a capacity/commodity charge by a 90/10 ratio.

Transmission tariffs refer to booking and use of pipeline capacity. The transmission tariff coefficients are as follows:

Year	Capacity Charge (€/peak day MWh/year)	Commodity Charge (€/MWh/year)
1.1.2006-31.12.2006	693,285	0,341087
1.1.2007-31.12.2007	625,589	0,307781
1.1.2008-31.12.2008	541,121	0,266224

Future years	CPI adjustment

The capacity charge is applied to the maximum daily booked/used transportation capacity during the respective year, while the commodity charge is applied to each MWh of gas being transported during the year.

LNG tariffs refer to booking of and use of vaporization capacity and –implicitly- to the respective LNG reception services and temporary storage. There is no tariff for long-term storage services as yet.

The tariff coefficients are as follows:

Year	Capacity Charge (€/peak day MWh/year)	Commodity Charge (€/MWh/year)
1.1.2006-31.12.2006	29,088	0,021947
1.1.2007-31.12.2007	26,247	0,019804
1.1.2008-31.12.2008	22,703	0,017130
Future years	CPI adjustment	

The capacity charge is applied to the maximum daily booked/used send-out capacity during the respective year, while the commodity charge is applied to each MWh of LNG regasified during the year.

Ministerial Decision 1781/2006, which amends MD 4955/2006, sets a cap on average network charge for peak power producers (open cycle gas turbines) which for year 2006 was 14.95 €/MWh.

Ministerial Decision Δ1/5037/2007 which also amends MD 4955/2006, determines the level of capacity reservation in the gas Transmission System for electricity power producers, as percentage of the technical capacity of each power unit.

B. Distribution tariffs

Local distribution companies (EPA) set there tariffs under a revenue cap which is adjusted every year according to CPI. The tariff is bundled (i.e. there is no separate charge for transmission and distribution of gas) and each EPA follow a different methodology in order to calculate there tariffs (market value or cost plus).

C. Average charges

The estimated national average network charges for typical customer I4-1 are as follows:

Year	Average Charge (€/MWh) – LF 45.7%
2006	4,50
2007	4,06
2008	3,51
Future years	CPI adjustment

The other two types of typical customers (I1 and D3) are supplied by Local distribution companies. An indicative charge for transmission and distribution of gas (no cost of gas included) in the area of Thessaloniki is presented below:

Typical customer	Average Charge (€/MWh) 1.1.07-30.6.07
D3	14.86
I1	14.16

D. Storage charges

Greece has no storage facilities except from the LNG tanks in the Revythoussa LNG terminal. So far TPA to the terminal is related only to the offloading, temporary storage and regassification of LNG i.e. no storage service is provided.

4.1.3.2 Balancing

Balancing arrangements and the respective charges will be defined in the Network Code, pursuant to article 8 of the Gas Law.

4.1.4 Effective Unbundling

Following the implementation of law 3428/2005, the establishment of the HGTSO took place in February 2007, under the name “DESFA”. The new company is a 100% subsidiary of DEPA the incumbent gas company in Greece (legal unbundling). DESFA 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 Revythousa island. DESFA is the only gas system operator in the country.

Management and functional unbundling of DESFA is required by the law. The detailed rules for such unbundling will be further elaborated in the terms of DESFA’s authorization, currently under drafting. Additionally, the Gas Law provides for a Compliance Code which shall specify the obligations of the staff and management of DESFA so as to avoid any discriminatory behaviour regarding TPA to the NNGS, the measures for the implementation of the Code and a control of compliance system. Until the 31st of January of each year, the

HGTSO shall submit to RAE a report describing the measures taken in relation to the observance of the Compliance Code. This report shall be published by the HGTSO. On the basis of that report, RAE shall evaluate annually the extent of independence of the HGTSO and may propose measures for further safeguarding of independence.

Regarding accounting unbundling, according to the provisions of the Gas Law:

- All integrated natural gas undertakings should keep and publish unbundled accounts for the activities of transmission, LNG installation, storage, distribution and other natural gas activities, as well as other activities not related to natural gas as if those activities were operated by different companies. Furthermore, all companies exercising natural gas activities are obliged to keep and publish unbundled accounts for the activities of supply of natural gas to eligible customers and supply of natural gas to non-eligible customers as well as for the cost of provision of public service obligations. Unbundled accounts should be audited by a certified accountant. The audit should address all the requirements set by the law and its outcome should be submitted to RAE. RAE has the right to conduct inspections in order to maintain these requirements. Finally, RAE has the right to impose a fine to any company that violates the relevant provisions of the Gas Law.
- Existing gas distribution concessions are exempted from functional unbundling requirements (article 28 of the Gas Directive) but are obliged to keep separate accounts for their gas distribution and supply activities. Therefore, based on the above provisions, the three existing gas distribution companies (EPAs) are obliged to keep unbundled accounts for the activities of distribution and supply of gas, or for any other activities.
- For new gas distribution concessions that may be granted in the future, the Gas Law provides for the application of the “100.000 customers” rule regarding functional unbundling, and the obligation for accounting unbundling.

DEPA SA, the Greek incumbent, has not published unbundled accounts as yet, since its subsidiary company DESFA, the HGTSO, was just established this year. The gas distribution companies (EPAs) are preparing for the accounting unbundling process and are expected to publish unbundled account for the financial year 2008.

4.2 Competition Issues [Article 25(1)(h)]

As explained above, competition is not yet established in the Greek gas market.

5 Security of Supply

5.1 Electricity [Article 4] [1]

5.1.1 Supply – Demand Situation

The evolution of energy and peak power demand for the interconnected system for the years 2005 to 2007 is shown in the next table.

Table 5.1: Energy and peak power demand for the interconnected system

	2005	2006	2007
Electricity consumption excluding pump storage (in GWh)	**52500.8**	**53656.8**	
Peak load (in MW)	9635 (9800 incl. curtailed load)	**9962**	**10610**

Forecasts for energy and peak power demand for the years 2007-2011 are presented in the HTSO´s five-year plan for the development of the transmission system. According to the scenarios of the HTSO, the evolution of energy and peak power demand is forecasted as follows:

Table 5.2: HTSO scenaria / forecasts for yearly energy demand in the interconnected system

	Low			**Reference**			**High**		
year	*Demand (GWh)*	*Yearly rate (%)*	*Yearly increase (GWh)*	*Demand (GWh)*	*Yearly rate (%)*	*Yearly increase (GWh)*	*Demand (GWh)*	*Yearly rate (%)*	*Yearly increase (GWh)*
2006*	54.000			54.000			54.000		
2007	55.350	2,5	1.350	55.620	3,0	1.620	55.900	3,5	1.900
2008	56.730	2,5	1.380	57.290	3,0	1.670	57.850	3,5	1.950
2009	58.150	2,5	1.420	59.000	3,0	1.710	59.870	3,5	2.020
2010	59.600	2,5	1.450	60.780	3,0	1.780	61.970	3,5	2.100
2011	61.100	2,5	1.500	62.600	3,0	1.820	64.140	3,5	2.170

*Εκτίμηση

[1] This section may make reference to supply demand forecasts compiled by TSOs where appropriate

Table 5.3: HTSO scenaria / forecasts for yearly peak demand in the interconnected system

Year	**Low**	**Reference**	**High**
2007	9880	10290	10870
2008	10130	10540	11130
2009	10375	10790	11390
2010	10620	11045	11650
2011	10870	11300	11925

Regarding the non-interconnected islands, the synchronised peak-demand is not calculated since the corresponding load profiles are quite different between the islands. The total energy consumed during 2006 on these islands was 5287 GWh, an increase of about 5.8% from 2005.

5.1.2 Generation Capacity and Licensing

By 31.12.2006 the total 11.653,8 MW of total net generation capacity in the interconnected system is distributed as follows:

PLANT TYPE	installed capacity (net) in MW
lignite	4.808,1
HFO	718
GTCC	1.962,1
natural gas - other	486,8
hydro plants	3.016,5
RES and small cogeneration	660,3
Other cogeneration	108

On the non-interconnected islands, the total maximum available net generation capacity was about 1.440 MW in 2005 and about 1600 MW in 2006, all coming from HFO and LFO units. In addition, in 2005, 164 MW of wind generators were connected to the distribution network of the non-interconnected islands, as compared to 200MW in 2006. Total installed capacity in these islands is expected to increase by 7% to 10% per year for the next 3 years.

Licensing & Tenders for new capacity

According to RAE´s records, there are currently 14 generation licenses granted to anticipated gas-fired IPPs, for a total capacity in the order of 5,000 MW for the interconnected system.

Concerning short-to-medium term prospects for new capacity, interest for the wholesale electricity market by private investors looks more positive than previous years; three private industrial groups have announced their intention to install GTCC units, of total capacity in the order of 1200 MW, before the end of the decade.

Furthermore, interest for developing coal plants has appeared: three applications for generation license concerning approx. 1600 MW of total capacity have been submitted to the Regulator during the last three months.

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. There were 4 participants to the tender and currently the tender is in its final stage, delayed by a complaint filled before the European Competition Committee concerning the procurement proceedings and the legality of the contract to be concluded.

Concerning RES, the situation is presented in the following Table. By 31.12.2006, the RES capacity installed amounted to approximately 750 MW (large hydro not included).

Table 5.4: Licensed RES plants (as of 31.12.2006)

RES TYPE	COMMERCIALLY OPERATING		With INSTALLATION LICENSE		With GENERATION LICENSE		RECALLED		APPLICATIONS FOR GENERATION LICENSE	
	(MW)	%	(MW)	%	(MW)	%	(MW)	%	(MW)	%
WIND	635,4	84,8	912,3	87,3	6146,3	90,8	524,3	82,2	29473,7	92,0
BIOMASS	24,0	3,2	29,8	2,9	97,5	1,4	21,8	3,4	384,5	1,2
GEOTHERMAL	0,0	0,0	0,0	0,0	8,0	0,1	0,0	0,0	335,5	1,0
SMALL HYDRO	89,2	11,9	102,1	9,8	518,1	7,7	91,2	14,3	1637,5	5,1
PVs	0,8	0,1	0,9	0,1	2,2	0,0	0,1	0,0	188,2	0,6
TOTAL	**749,4**	**100,0**	**1045,1**	**100,0**	**6772,1**	**100,0**	**637,5**	**100,0**	**32019,4**	**100,0**

5.1.3 Generation fuel mix and expected developments

For the interconnected system, fuel mix current situation and forecasts are as follows:

Table 5.5: Generation Fuel Mix 2004-2006

	2004		2005		2006	
	(GWh)	(%)	(GWh)	(%)	(GWh)	(%)
Lignite	32491.4	62.8	32056.6	60.0	29165.17	53.43
Fuel Oil	2687.5	5.2	3302.2	6.2	3309.1	6.06
N. Gas	8037.6	15.5	7944.6	14.9	10169.1	18.63
Large Hydro	4926.6	9.5	5420.6	10.2	6229.4	11.41
RES	757.8	1.5	894.8	1.7	1511.7	2.77
Net Imports	2820.6	5.5	3780.9	7.1	4202.4	7.7
Total	51721.5	100.0	53399.7	100.0	54586.9	100.0

Source: HTSO

Table 5.6: Generation Fuel Mix 2007 - 2011

	2007		2008		2009		2010		2011	
	GWh	%	GWh	%	GWh	%	GWh	%	GWh	%
Lignite	30600	54.7%	32500	56.9%	32500	55.6%	32000	53.5%	31000	50.4%
Fuel Oil	3200	5.7%	2420	4.2%	1555	2.7%	860	1.4%	910	1.5%
N. Gas	13300	23.8%	13700	24.0%	14500	24.8%	16500	27.6%	18300	29.8%
Hydro	3200	5.7%	3580	6.3%	4260	7.3%	4210	7.0%	4210	6.8%
RES	1820	3.3%	2330	4.1%	2975	5.1%	3680	6.2%	4380	7.1%
Net Imports	3800	6.8%	2620	4.6%	2700	4.6%	2550	4.3%	2700	4.4%
Total	55920	100	57150	100	58490	100	59800	100	61500	100

Source: RAE´s estimates

5.1.4 Authorization criteria for new generation investments and the role of long term planning

According to the law, the general criteria applied for the granting of generation licenses are:

a) The safe and sound operation of the Electricity System, including the network, the generation installations and all relevant equipment.

b) The protection of the consumers and the environment

c) The efficient production and use of electricity

d) The primary source of energy and the technology used

e) The technical, economical and financial capacities of the investor

f) The maturity of the proposed project

g) The provision of public service obligations

h) The long-term energy planning of the country

j) Issues of national security

For granting a license to a hydro power station, the integrated development planning and energy management of the affected hydrological potential is also taken into consideration.

Although long-term planning is not usually taken explicitly into account during the licensing process, various factors (such as environmental issues, fuel mix, etc) are taken into account when licensing large generating units. For example, during the 2001 RAE´s call for submission of applications for licensing of electricity generating units, a restriction was imposed which excluded the Attica region (contains the Athens metropolitan area) as a candidate area for installation of large scale, fossil-fuelled, units. However, following a partial black-out in 2004, caused mainly by low voltages in the south part of the country´s interconnected system, this constraint was released.

Furthermore, various medium-to-long term analyses are undertaken by RAE on an ad-hoc basis in order to examine the effects of specific categories of generating units (eg. peaking units, coal units, etc) to various parameters of the interconnected system, such as costs to cover peak load, GHG emissions, economic viability of investments in generating units, etc. Furthermore, the interrelationships between the energy sector, including environmentall effects, and the rest of the economy are studied using specific analytical models.

5.1.5 Incentives to build capacity

The 2005 Grid and Market Operation includes a Generation Capacity Assurance Mechanism. This Mechanism aims to ensure long-term capacity availability and is based on the obligation of the suppliers to present sufficient guarantees in that direction. Moreover, the mechanism aims to reduce the generator's business risk, by guaranteeing part of his 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 this Capacity Assurance Mechanism, generators and importers issue annual Capacity Availability Tickets (CATs, in one MW steps) reflecting their total net generating capacity and import rights. CATs are submitted to the CAT Register, kept by the TSO, and constitute an offer to the suppliers for the conclusion of Capacity Availability Contracts (CACs). Suppliers have to conclude these CACs to cover their supply obligations plus a security margin.

When capacity shortage is foreseen and is not expected to be covered by IPP initiatives, the TSO can proceed to a tender for the pre-purchase of CACs, corresponding to new generating units. The CACs pre-purchase is done on behalf of the future suppliers and customers, to whom the TSO should transfer the CACs 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 2008, and due to the possible difficulty in the conclusion of CACs between suppliers and generators, the following alternative mechanism is offered:

- Generators may conclude CACs with the TSO.
- The capacity obligations of suppliers can be covered by the above CACs, upon conclusion of a "Contract for Participation in the Transitional Capacity Assurance Mechanism" between the suppliers and the TSO.
- A regulatory defined uplift is charged to all participating suppliers, according to their customers' peak loads, and is received by all participating generators depending on their unit availability.
- The value of the uplift has been set at 35.000 €/MW, based on the costs of unit installation and of keeping units at the highest levels of operational availability.

5.1.6 Transmission system development

According to the Grid & Market Operation Code, the HTSO establishes and publishes, at least every two (2) years, a regular 5 year estimate of the generating and transmission capacity that is likely to be connected to the Transmission System, the interconnection needs to other Systems or Networks, the transmission capacity needs and the electricity demand.

Moreover, the 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 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 access to anyone wishing to connect to the transmission system[2]. In this framework, the HTSO elaborates and publishes annually the five-year plan for the development of the interconnected transmission system, which is approved by the Minister of Development following RAE's opinion and the views of the owner of the transmission system (PPC). The procedure for the elaboration of the five-year plan for the development of the transmission system is specified in detail in the 2005 Grid & Market Operation Code. In this plan, the development projects are specified, as well as the progress timeframe and the estimated costs.

PPC S.A., as the owner of the transmission system, is responsible for the reinforcement of the existing transmission system. In case that PPC invokes inability either to respect the time schedule or to finance a specific project, a third party can undertake this project.

The projects that refer to extensions of the transmission system in order to connect new facilities, can be executed either by the interested for the connection party or by the owner of the transmission system.

As far as congestion is concerned, the steady state system security is evaluated for 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 determine the necessary system development to secure reliable and economic operation.

5.1.7 Interconnection projects

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. Project completion is expected in the 1st quarter of 2008. However, full operation of the interconnection should be expected following the official procedure for the interconnection of the Turkey transmission system with the UCTE system..

Upgrade of interconnection with FYROM: Upgrade of the existing 150 kV line between Greece and FYROM, to 400 kV was completed in June 2007. The upgraded line contributes to a potential increase of total import capacity of the Greek system by approximately 150-200 MW, when energy is supplied from FYROM or the western part of the Balkans area. The full potential of the new line will be exploited when a strong interconnection exists between Bulgaria and FYROM (400 kV line Skopje – Stip – C. Mogila), which is expected to be completed in 2008.

[2] According to the provisions of the new Law 3426/2005, the HTSO may refuse connection to the system where it lacks the necessary capacity. Duly substantiated reasons must be given for such refusal, in particular having regard to the necessary system reinforcements

<u>New interconnection with Bulgaria</u>: The construction of a new line between Greece and Bulgaria has been studied but no agreement has been signed so far between the two countries for the construction of the project. The Bulgarian HTSO has requested to investigate the alternative construction of an alternative tie-line to connect to the new EHV substation that will be built close the Greek-Turkish border.

All new infrastructure in the Greek territory will form part of the assets of the transmission system and its cost will be recovered though transmission use of system charges.

5.2 Gas [Article 5]

5.2.1 Ongoing Supply-Demand Situation

In 2006, the total gas consumption in Greece reached 3.12 Gm3.

The gas demand forecast for the period 2007-2008, is presented in the following table, broken down in consumer categories:

Gas Demand (Mm^3/year)	2006	2007 (f)	2008 (f)	2009 (f)
Electricity Generation	2.175	2.528	2.918	3.651
Large Industries	529	784	837	798
Small Industries	155	338	370	403
Commercial and domestic	245	386	518	639
Other	13	25	30	30
Total	**3.117**	**4.061**	**4.672**	**5.521**

Greece has no domestic gas production. So far, gas is supplied by means of the following long-term, take-or-pay contracts held by DEPA:

1. A contract for the supply of pipeline gas from Russia (2,80 Gm^3/year).
2. A contract for the supply of LNG from Algeria (0,68 Gm^3/year)

DEPA has also concluded a new long-term, take-or-pay contract with Turkish Botas. The contract provides for the import of 0,75 Gm^3/year from Turkey at the initial stage, after the completion of the Greece-Turkey interconnector, which is expected to be operational by the second half of 2007.

5.2.2 Currently available import capacity

The maximum importing capacity of the entry point from Bulgaria is currently 360,000 m^3/h corresponding to an annual throughput of approximately 3.2 Gm^3/year and will be expanded to 691,000 m^3/h by the end of 2007, corresponding to an annual throughput of approximately 6.0 Gm^3/year.

The second entry point to the NNGS is the Revythoussa LNG terminal. After a recent expansion, the current maximum sustainable send out rate of the LNG Terminal is 1000 m^3 LNG/hour or approximately 590,000 m^3/h corresponding to an annual throughput of 5.2

Gm^3/year. The net storage capacity of the LNG tanks is 130,000 m^3 of LNG, while the unloading capacity of the terminal equals 7,250 m^3 LNG/hour.

5.2.3 Forthcoming import investment for the next three years

The only new import infrastructure project currently underway is the Turkey-Greece Interconnector, expected to be operational in the second half of 2007. The initial import capacity of the Interconnector is estimated to 3.5 Gm^3/year.

5.2.4 Other infrastructure projects

In November 2005, Italy and Greece signed an intergovernmental agreement for the development of the Interconnection Italy Greece (IGI) project. The project involves the construction of both an onshore and offshore pipeline linking the two countries and thus enabling the flow of gas through Greece to Italy and Europe. The initial capacity is estimated to 8 Gm^3/year, extendable to approx. 10 Gm^3/year in the future. The project is sponsored by DEPA S.A. and Edison S.A. The onshore part crossing mainland Greece will be under a full TPA regime and it will be constructed by DESFA the HGTSO. For the offshore (sub sea) part, in early 2007, the two companies filed for an exemption with the Italian Authorities and the Commission. In June 2007, an exemption was granted under specific conditions.

6 Public Service Issues [Article 3(9) electricity and 3(6) gas]

6.1 Electricity

6.1.1 Public Service Obligations

According to the provisions of the Law 2773/1999, as amended by law 3426/2005, the Minister of Development can impose public service obligations to market participants (authorised generators, suppliers, network operators and network owners), in order to ensure security and continuity of supply, quality of service, consumer protection, protection of the environment. Market participants are required to abide by such ministerial decisions for the provision of public services, as per the terms and conditions of their license.

According to the provisions of the Law 3426/2005, the Minister of Development defines the PSO's categories and the providers of those services within 6 months from the publication of the Law. Then, in three months time from the decision of the PSO's categories, the Minister of Development after RAE's opinion, approves the methodology for the allocation of PSO costs, within each category of consumers. The level of the levy required for the provision of PSO's is annually approved by the Minister of Development after the opinion of RAE. The providers of PSO's are obliged to maintain separate accounts for PSO costs and charges. These accounts include in a transparent way the economic rent owed to the PSO provider as well as the charges allocated to their customers concerning PSO expenses.

Consumers located in non-interconnected islands enjoy electricity supply service at the same tariffs as any other customer regardless of the cost of their connection and supply. The difference between the cost of providing electricity on the non interconnected islands and tariffs applied to the consumers of the islands is considered as provision of public service, and should be compensated by a special PSO levy. Currently this levy is incorporated in the unbundled PPC tariffs. The decision to apply the same tariffs in the whole of the country is taken as a measure to promote social cohesion.

In addition, groups of vulnerable customers under certain specified conditions (e.g. families with more than three children) enjoy a discount tariff by PPC, as a measure of social support. There are also special discount tariff regimes for consumers in the agricultural sector and for the employees of PPC.

In June 2007, by a Ministerial Decision of 25.6.2007, the following public services were defined for the electricity sector: (a) supply of electricity to non-interconnected islands and to remote micro-grids with tariffs equal to those of the mainland´s interconnected system and (b) reduced tariffs for the supply of electricity to consumers / families with many children. RAE has already expressed its opinion on the methodology for the estimation of the annual fee that the providers of PSO should receive.

No obligation for primary energy source labelling exists so far. Nevertheless, recent Law 3468/2006 provides for a procedure that all producers are able to issue energy source certificates by applying to the HTSO or to the operator of the non interconnected islands network. The mechanism is monitored and controlled by the RAE.

6.1.2 Supplier of Last Resort

PPC is obliged to supply eligible customers who will not be supplied by other suppliers. In such cases, PPC has the right to charge fees to recover potential additional cost caused by the fact that the customer was previously not supplied by PPC. These fees are set by decision of the Minister of Development following an opinion by RAE and are calculated by PPC for each customer category.

6.1.3 Measures to guarantee eligible customers' ability to switch to a new supplier and the provision of information regarding supply contracts

According to the current Supply Code, each supplier following the granting of a supply license, must publish the supply terms that he applies to eligible customers (structure of tariffs, charges imposed and the principles applied for the estimation of these charges and the Supply Contract terms) in at least two (2) national daily newspapers and in one (1) local newspaper. Additionally the licensee should publish any modifications on the terms and conditions (tariffs, method or pricing, terms of the contract etc). The publication takes place one month prior the date of granting of the supply license and one month prior to the date of any modification of the supply license.

Offers of service to customers are made in written from, are binding on the part of the Supplier and stipulate all charges imposed and pricing, as well as the general and any special terms of the supply contract.

Supplier switching is allowed following unilateral termination by the part of the customer of the previous supply contract and cannot be impeded by reason of unsettled debt towards the previous supplier. Suppliers may exercise their lawful rights for claims against clients related to unsettled debt. Dispute settlement regarding outstanding debt are referred, from either parties, to arbitration by RAE. Suppliers are obliged to provide customers with all information needed to complete the switching process (i.e. meter readings), as well as any information needed by the System or Network Operators, within 14 days of customer's notice.

6.1.4 Supply contract terms

According to the provisions of the Supply Code and with reference to consumer protection, the following general terms and conditions apply to supply contracts with eligible customers:

- Customer right to request meter accuracy check, with the relevant costs borne by the Supplier in case of failure to meet accuracy standards.

- Contract prepayments are limited to an amount corresponding to payment for services rendered over a period of 3 months.

- Unilateral contract termination is foreseen with a minimum notice of 3 months (termination by the part of the customer) and 12 months (termination by the part of the supplier).

- Unilateral termination of the contract by the supplier with less than 3 months notice is possible a) in case of unsettled debt (45 days following payment date expiration) and b) in case of breach of contract terms by the customer.

The standard terms and conditions of the Supply code that apply to the supply contracts have not yet been established in PPC's supply contracts. The same holds for the minimum standards of the commercial quality. So far PPC SA has not unbundled its contracts in a Connection Contract and a Supply Contract.

According to the current PPC supply contracts, which are not yet harmonised with the Supply Code requirements, the customer can withdraw from the contract no later than 30 days and not earlier than 10 days from each cycling period (ie the cycling period is renewed every 12 months, from the contract date, for another year). In addition if the customer withdraws earlier than 5 years, he should pay the rest fixed fees. However those terms have not been applied in practice, since the Greek legislation protects the consumer from the terms of Adhesion contracts.

6.1.5 Regulation of end user prices

In so far that PPC retains at least a 70% market share of the supply to eligible customers, all its supply tariffs to eligible customers are regulated and fixed by the Minister of Development after opinion by RAE. The approval of the supply tariffs is based on total cost-plus calculations. PPC provides evidence of annual growth of cost elements, as for example inflation rates and changes in energy fuel prices and then the decision takes the form of allowed percentage change of all tariff levels and parameters. The tariffs are defined per category of customer (e.g industrial, commercial, domestic, etc.) and are not related to eligibility or not of the customer.

6.2 GAS

6.2.1 Public Service Obligations

According to the provisions of the Gas Law 3428/2005, public service obligations may be imposed by the Minister of Development to the HGTSO and all other authorization holders.

More specifically, PSOs related to security and continuity of supply, quality and price of service and environmental protection (including climate protection and energy efficiency) can be imposed to the HGTSO by means of a Ministerial Decision. HGTSO's cost for providing the PSOs shall be recovered through regulated discreet charges applicable to the users of the NGS.

In addition, according to the provisions of the regulation for granting, amending and revoking authorizations in the gas market, PSOs can be imposed to all authorization holders by means of a Ministerial Decision issued after RAE's opinion. Additional obligations can be imposed to such entities in cases of extreme and adverse climate conditions as well as for national and public security reasons.

6.2.2 Supplier of Last Resort

There is no supplier of last resort provision as such in the Greek Gas Law. However, according to the provisions of same Law, in emergency situations, all supply authorisation holders that supply gas to small consumers (i.e. consumers with consumption less than less than 9 Mm^3/year) are obliged to continue the supply of gas to all such consumers i.e. irrespectively if they are their customers, following the instructions of HGTSO. For the provision of last resort gas supplies, supply authorisation holders will be fully compensated, in accordance with the terms of their authorisation.

6.2.3 Measures to guarantee eligible customers' ability to switch to a new supplier and the provision of information regarding supply contracts

The subject is relevant to the provisions of the Supply Code to Eligible Customers. The Supply Code is part of the Gas Law's secondary legislation and is estimated to be enacted by end-2007.

6.2.4 Supply contract terms

As far as eligible customers are concerned, the subject is relevant to the provisions of the Supply Code to Eligible Customers (see also section 6.2.3 above).

For non-eligible customers supplied by the gas distribution companies (EPAs) under a concession regime, standard terms and conditions of the supply contract are imposed by the Distribution Licence and include:

1. Obligations of the supplier regarding invoicing (frequency, structure, pricing principles), settlement of disputes over meter readings, duration/renewal of contract etc.)

2. Obligations of the customer regarding access of the company to his premises and to the meter, due payment of bills, connection fees etc.

The duration of the supply contract is one (1) year and is automatically renewed unless the customers notifies the company otherwise. The customer can withdraw from the contract at any time without any charge.

6.2.5 Regulation of end user prices

Until today, the tariffs for the supply of customers not belonging to EPAs are set by DEPA SA without any involvement of the Regulator, or the government. The end user tariffs of the EPAs are set by the distribution companies (EPA) and are controlled ex-post by RAE for compliance to the terms of their license.

7 ANNEX I - Methodology for computation of Transmission Network Tariffs

The methodology and procedure for setting transmission network tariffs (according to the 2005 Grid Code) is as follows:

I. Annual System Cost

The HTSO calculates the annual System cost using the following formula:

$$E = E1 + E2 \pm \Pi 1 \pm \Pi 2$$

where

- E is the annual System cost,
- E1 the annual barter owed by the HTSO to the Owner of the System (PPC SA), which is calculated below,
- E2 is the annual cost of System Works paid by HTSO,
- Π1 is the non recovered cost (+) or surplus (-) from generators (including importers) during the current fiscal year and
- Π2 is the non recovered cost (+) or surplus (-) from Load (customers and exporters).

The barter owed to the Owner of the System by the HTSO on a yearly basis and which corresponds to variable E1 is calculated as follows:

$$E1 = O + A + (V - D) \times \rho$$

Where

- O is the annual operation and maintenance expenses and also the indirect expenses, borne by the Owner of the System (PPC SA), as are budgeted using the accounts unbundling rules. These expenses include also the maintenance expenses of users connection assets.
- A is the annual depreciation of transmission assets, as are budgeted using the accounts unbundling rules;
- V is the budgeted average initial value of the initial System assets based on acceptable evaluation methods and the budgeted average value of operating capital of transmission;
- D is the budgeted average value of aggregated depreciation for the System assets
- ρ is the nominal pre tax rate of return of invested capital in total capital which is approved by RAE, according to regulation policy and international practice and experience.

II. Method for the allocation of the cost of the System to the users

The HTSO allocates the Annual System Cost to all System users (injecting and absorbing energy) and calculates a charge for each user.

The charge corresponding to each user is calculated on an annual basis as the product of the user's chargeable output multiplied by the unit charge corresponding to such user category. The unit charge is expressed in Euro/MW. The charge for generation units for using the System does not change due to scheduled shut down of units due to maintenance or fault.

The annual System cost is allocated to all generation units, including imports, (G), and load, including exports, (L), as follows:

a) 2 % of the sum of E1 and E2 increased or decreased by Π1 is allocated to all G.

b) 13% of the sum of E1 and E2 increased or decreased by Π1 shall be allocated to G connected to system nodes in the Prefectures of Evros, Rodopi, Xanthi, Drama, Kavala, Thessaloniki, Halkidiki, Kilkis, Serres, Pieria, Grevena, Florina, Pella, Imathia, Kastoria, Kozani, Larissa, Trikala, Karditsa, Magnisia, Fthiotida, Thesprotia, Preveza, Ioannina, Arta, Kefallinia, Lefkada, Zakinthos and Corfu.

c) 85% of the sum of E1 and E2 increased or decreased by Π2 shall be allocated to L.

The unit charge for each of the cases a and b of the previous paragraph is calculated by dividing the annual transmission cost allocated to G for each case by the sum of chargeable outputs for G included in each case.

The unit charge allocated to Load is uniform throughout the territory and is calculated by dividing the annual transmission cost allocated to Load by the sum of chargeable outputs for customers.

III. Approval of Annual System cost and unit charges

By September 30th each year, the HTSO drafts the budget for the next year, which includes:

a) the annual cost of the System

b) the budgeted income of HTSO from the use of the system charges for the next fiscal year, based on the use of the system unit charges and the expected total demand of electricity.

c) any differences between the sum collected by the HTSO from G and L for use of the System and the real transmission cost during the current fiscal year, which shall be credited or debited to the transmission cost budget for the following year.

The operating expenses of the HTSO are not included.

The budget of the annual cost of the System, including the annual barter owed to the Owner of the System, the annual cost of the System and the calculation of the use of the system charges are approved by RAE.

Following approval of the budget, the HTSO shall calculate if necessary, until 31st of October each year, the unit charge corresponding to customers and generation units for each charge zone for the following fiscal year.

The unit charges are approved by the Minister of Development following RAE's opinion.

8 ANNEX II - The wholesale electricity market under the 2005 Grid and Market Operation Code

Concerning the wholesale electricity market, a mandatory pool system (the Pool) has been introduced. The overall market design includes

1. the Day Ahead Scheduling (DAS) which includes the hourly transactions of the total energy injected to the system and consumed daily,
2. the Dispatch Procedure,
3. the Imbalances Settlement which includes the settlement of energy deviations, and
4. the settlement of the services required for balancing of the system.

In addition, a Capacity Assurance Mechanism has been adopted, through which part of the fixed costs of generating capacity are covered.

The supervision of the Pool is assigned to the Regulatory Authority for Energy (RAE). RAE is in charge of supervising the actions, with reference to rights and obligations, of the System Operator (the HTSO) and the Participants, as far as the System and the Market are concerned.

Participants in the Pool are the Producers who are production license-holders enlisted in the Unit Register, the Suppliers who are supply license-holders, representing their customers' load, importers and exporters of electricity and Self-Supplying Customers, who are Eligible Customers choosing to absorb electricity from the Power Exchange System exclusively for their own use.

Day Ahead Schedule (DAS)

The DAS constitutes the first stage of the wholesale electricity market process, aiming at the daily minimization of the total cost that is required for serving the load and meeting ancillary services requirements (primary & secondary reserves), taking Transmission System Constraints into consideration, in order to arrive at a solution that closely approximates the Real Time Unit Dispatch. In order to achieve this target, the System Operator prepares on a daily basis the Day Ahead Schedule of the Dispatch Day (i.e. the day of the physical delivery of energy), where the total load is contrasted to the economic injection offers for energy. All procedures and transactions concerning the DAS are concluded within the day that precedes the Dispatch Day. Charges and payments for the energy scheduled to be absorbed or injected according to the DAS Schedule, are calculated and settled within the day ahead. Charges and payments for reserves and ancillary services are calculated and settled through the Imbalances Mechanism.

Real Time Dispatch

The objective of the Dispatch Procedure is to schedule the operation of Dispatchable Units, Contracted Units and Cold Reserve Units, as well as the issuing of Dispatch Instructions in real time from the System Operator, in order to ensure that the total absorption of energy from the System, according to the forecasts and the measurements of the System Operator, is carried out according to terms of good faith, reliable operation of the System, capability of facing emergency events and minimization of the total cost. The Dispatch Instructions are issued according to the Dispatch Schedule.

Imbalances Settlement

The Imbalances Settlement includes clearing of transactions with respect to energy deviations (due to Imbalances, forced and unforced production changes), Ancillary Services and Uplift Accounts. So, during the Imbalances Settlement and for each Dispatch Day, the System Operator calculates:

- The quantity of energy corresponding to Imbalances, forced and unforced production changes, which are thereby attributed to each Participant for each Dispatch Period.

- The debit or credit corresponding to the Imbalances of each Participant for a Dispatch Day, as well as the additional debit or credit corresponding to the forced and unforced production changes of each Participant for the same Dispatch Day.
- The payment of each Participant for the provision of Ancillary Services, the readiness to provide Supplementary System Energy and Cold Reserve Services, through the Uplift Accounts.
- The debits and credits of the Uplift Accounts.

In order to achieve higher availability of the generating units and to properly allocate the imbalance costs to those who cause them in the context of Imbalances Settlement, the following rules apply:

- Imbalance is defined, separately for each Injection Offer and Load Declaration, and separately for each Dispatch Period. It is the difference between the scheduled energy in the DAS and the measured energy.
- Unforced production change of a Unit for a Dispatch Period is defined as the difference between the energy quantity as given by the Dispatch Instructions for injection into the System and the measured energy.
- Forced production change of a Unit for a Dispatch Period is defined as the difference between the scheduled energy in the DAS and the energy quantity as given by the Dispatch Instructions for injection into the System. The forced production changes of a Unit are due to Dispatch Instructions that were issued by the System Operator, principally for the adjustment of production of the Unit and the provision of Ancillary Services and Supplementary Energy.

In the above framework, calculation of energy deviations is performed separately for every Participant, with separate calculations for each Load Declaration and Meter, each Production 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 an Imbalances Market. In this context:

- The Imbalances Settlement clears at a uniform price, the Imbalances Marginal Price, which is calculated in such a way so that it will encourage the availability of the units.
- The System Operator (HTSO), in its capacity as Market Operator too, should aim that the cost of the Imbalances is allocated to the partiers that cause them.
- The System Operator (HTSO) should aim towards the minimization of the total Imbalances Settlement cost.

The Imbalances Marginal Price is calculated hourly using the DAS algorithm, but considering the actual availability of the units and actual load that was absorbed. Regarding forced and unforced production changes, each Unit can be debited or credited an amount additional to the Imbalances Settlement debit or credit, depending on the circumstances.

The Imbalances Settlement procedure is completed within 4 days following the Dispatch Day.