2008 National Report to the European Commission

Greek Regulator
Regulatory Authority for Energy (RAE)

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i. List of Acronyms

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

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1 Foreword

2007 has brought further acceleration to the liberalization of Electricity and Natural Gas Markets, as well as the effective promotion of Renewable Energy investments. Market monitoring and regulation implementation activities intensified, the unbundling of transmission and distribution networks was advanced, competition enhancing domestic energy wholesale market and Cross Border Trade rules were clarified, and tangible results were observed. However, progress did not occur at the speed and extend that one could and should expect. A summary of the developments and next year's planned focus of activities is provided below.

In the Electricity sector, there were no major developments concerning the market structure in Greece in 2007. In the wholesale market, the incumbent utility, PPC S.A., retained an approximate 95% market share in terms of installed capacity, while maintaining a 99.9% share in the retail market that includes the last resort obligation. However, interest for the wholesale electricity market by private investors appears more positive than in the previous years, with four private industrial groups having announced their intention to install considerable generating capacity before the end of the decade which will allow them to enter the supply of the retail market by hedging against volatility risk in the wholesale market. RAE is continually working on the needed regulatory intervention to revise wholesale market rules so as to enhance competitive conditions, render the viability of independent generators more robust, and increase further the entry of independent producers.

Concerning unbundling of the distribution system operation, the respective organisational unit of PPC S.A. had to be transferred to the Hellenic Transmission System Operator (HTSO) by July 1st, 2007, which would then become a Transmission and Distribution System Operator (TDSO). The transfer of this PPC unit to the Transmission System Operator has not yet taken place. Nevertheless, the integrated utility, PPC S.A., has made progress towards achieving a satisfactory unbundling of accounts for each of its activities related to the electricity sector. RAE approved the principles, rules and unbundling methodology for PPC S.A. and the latter submitted unbundled accounts for the recent years. Legal unbundling of the operation of the distribution network has not yet been established.

The major issues dealt with in the electricity sector are:

- The Supply Code was amended, by allowing customers connected to the high voltage grid to freely negotiate either with PPC or other suppliers their retail tariff. PPC tariffs to high voltage customers were fully regulated until this amendment. Notably, the high voltage customers are allowed to negotiate special clauses, especially related to their ability to offer interruptible load, and develop tailor-made tariffs, adjusted to their special load profile and generally their ability to adopt their consumption to the time-varying cost of supply.
- PPC was asked to start publishing its retail tariffs unbundled per service provided. By separating the charges on the electricity bill, any future price increases will be allocated to the relevant specific service.
- A fuel charge mechanism was introduced, according to which, in case of sharp increases of the price or fuel oil and natural gas, fuel surcharge is calculated quarterly, to allow uncontrollable fuel cost by PPC to be passed to the final costumer
- After RAE's recommendation, the Minister of Development approved the methodology for the calculation of the Annual Cost of the provision of Public Service Obligations that result from the uniform end-user tariff application to all islands and discount on the tariff of large families.

Wind parks and small hydro units are currently supplying close to 4% of the energy consumed in Greece, and installed capacity has reached 7%. As the number of applications already submitted to

RAE reveals, Interest in further investment is accelerating significantly, and it is expected that by 2012, installed capacity will exceed 25%.

In the Natural Gas sector, 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, as well as dealing with matters concerning the implementation of the existing legislation. Important steps were taken during 2007 towards a liberalized market such as the establishment of the legally unbundled Hellenic Gas Transmission System Operator (DESFA) and the approval of the Standard Transportation Agreement. Moreover, it is worth mentioning the following developments:

- Significant work on the development of crucial secondary legislation, and especially the Network Code, was undertaken by the Regulator and the new Natural Gas TSO.
- Interconnection with Turkey was completed in the second half of 2007, creating the potential for transit flows to Europe and enhancing security of supply for the Greek and other European gas markets.
- RAE and the Ministry of Development offered positive opinion regarding the exemption requested by the Italian Authorities for the offshore part of the Italy-Greece Interconnector, according to the provisions of article 22 of the directive 2003/55/EC. The exemption was approved by the European Commission in June 2007.
- Domestic and foreign investors have shown an increased interest for natural gas transit through Greece towards Italy and the Balkans. Substantial amount of work has been allocated to accommodate such needs and incorporate in the secondary legislation provisions which will facilitate the implementation of transit gas flows, in full compliance with the legislation of the European Union.

RAE’s main objective remains the establishment of efficient electricity and natural gas markets, along with the efforts for environmental protection and improved security of supply. Along these lines, activity during the next year will focus on:

(i) Identifying all economic costs incurred in the respective sectors (high, medium and low voltage sectors), in order to contribute towards the establishment of rational and cost-reflecting tariff structures in the electricity market.

(ii) Strengthening of the operation of the wholesale electricity market and increasing the trust of the electricity market participants to it, since it has been proven a very valuable tool for the realization of new generation capacity from private investors.

(iii) Promoting the better operation of the electric interconnections of Greece with its neighbors, with the view to facilitate its role as an overlapping country between the existing EU regions and the newly established 8th region. Bold decisions and strong cooperation with all neighboring countries and especially Italy and Bulgaria will be required to this respect.

(iv) Planning for the ability of the electricity system to absorb and realize the renewable energy generation potential, especially wind power.

(v) Promoting the interconnection of Greek Islands to the mainland system, in order to achieve a major reduction of Public Service Obligation (PSO) costs, as well as reduce oil consumption and emissions and increase quality of the supplied electricity.

(vi) Further promoting the unbundling effort in the electricity sector so as to allow the entry of independent generators and suppliers. Severe efforts have to be exercised in this respect, since the legal and functional unbundling in transmission and distribution of the electricity sector remain the biggest open issues to be resolved.

(vii) Streamlining a reserves market that will supplement the energy market.

(viii) Providing for the low-income and socially-vulnerable consumers through carefully estimated PSOs.

(ix) Completing the secondary legislation (Network Code) regarding third-party access in the Greek Natural Gas System, including the regulation of transit flows.

(x) Setting up all necessary administrative procedures (Authorization Regulation) for new suppliers to enter the market, as well as the rules for exercising their activity (Supply Code).

(xi) Completing a concise framework for the security of supply in Greece.

Michael Caramanis

Chairman of RAE

July 2008

2 Summary / Major Developments in the last year

2.1 Basic organisational structure and competences 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.

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. All members' service period is 5 years that may be renewed only once.

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; their revocation or suspension is permitted only in case of serious criminal conviction or persecution.

To ensure administrative independence, RAE is financially independent. 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*". 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, Consumers and Environment, Systems Analysis, Energy Planning and International Affairs, and Decision Elaboration and Documentation) and in three (3) support units (Press and Public Relations, Administration, and Chairman's Secretariat).

As of 31.12.2007, the Secretariat of RAE consisted of 34 experts (namely 13 engineers, 10 lawyers, 5 economists and 6 of other fields) and 22 administrative staff. They have all been appointed after an open call, through a transparent procedure and objective criteria, supervised by ASEP (the greek independent administrative authority that ensures the transparent procedure of personnel hiring in the public sector). There is provision for a total of 66 expert personnel, 30 administrative personnel and 5 positions as President's deputies (appointed directly by the President). RAE has recently proposed to the Ministry of Development an internal reorganization, in order to meet the increased responsibilities, as well as those that will arise from the 3rd package.

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 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 License 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 regarding 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-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 product market, and participates in the Emergency Response Committee for Oil Supply Crises. 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.

- 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

During this reporting period[1], the structure of the electricity markets in Greece did not change noticeably. There was no progress regarding the functional and ownership unbundling of the vertically-integrated incumbent utility, PPC S.A., and only one new power generation plant entered the market. In the wholesale market PPC retained an approximate 95% market share both in terms of installed capacity and electricity generated, while enjoying a 99.9% share in the retail market.

However, major positive developments may be reported. PPC's unbundling of accounts per service provided, along with RAE's approved recommendations to (a) allow high-voltage customers to freely negotiate special terms, and to (b) restructure the retail tariffs for low- and medium-voltage customers, aimed at the elimination of tariff distortions due to cross-subsidies. Finally, the completion of the Distribution Code will facilitate the opening of the market, since it greatly reduces the uncertainty for suppliers to enter the market.

RAE continuous aim it is to enhance trust in the wholesale market, as this will increase investors' confidence and will bring new plants and enhance competition in production. When combined with required reforms in retail tariff structure already in progress, we hope that competition in retail will strengthen too.

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 48% reduction of the generation from such units compared to the already low 2006.

Additionally, during the summer of 2007 Greece experienced three major heat waves with several days of sustained high temperatures throughout the country, resulting to a new record of peak demand for the interconnected system, which was 10,610 MW, about 1000 MW higher than year previous one (August 2006).

Finally, as mentioned in last year's report, under the provisions of Law 3175/2003 and the new Grid and Market Operation Code, HTSO launched (May 2006) a tender for the installation of new generation capacity, for approximately 400 MW CCGT. 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

[1] General Note: all data included in this Report refer to 31-12-2007, or the period 1-1-2007 to 31-12-2007. By the time the Report was written (July 2008), new developments had taken place concerning the reporting issues. In such cases, the known developments will be briefly stated in footnotes but will be fully explained in next year's Report.

€35,000 per MW-year and it will be given for 12 years. There were 4 participants to the tender and during summer of 2008 the contract will be concluded with the winning bidder.[2]

Wholesale electricity market

Interest for the wholesale electricity market by private investors appears more positive than during the previous years. Several private industrial groups have started the construction of CCGT units of total capacity in the order of 1700 MW; the first one is expected to enter the market by the end of 2009. Furthermore, interest by private investors for developing plants has been registered: three applications for generation license concerning approximately 1600 MW of total capacity have been submitted to the Regulator, who has given positive opinion for two of these applications in 2007.

The increasing oil prices combined with the experienced dry year led to sustained high prices in the Greek Wholesale Electricity Market, especially during the high demand hours of the second half of 2007. Despite that, RAE's decision to impose the bidding of a separate offer curve for each of the 24 hours of the day led to a reduction in the low-demand hours SMP; thus the average yearly SMP increased only by 1.3%. More specifically, the average yearly SMP was at 64.94 €/MWh, with its average price during the low demand hours (02:00 – 07:00) at 47.10 €/MWh and during the high demand hours (12:00 – 24:00) at 72.53 €/MWh (see Annex I for SMP graphs).

Retail market opening

In the retail market, PPC's market share during 2007 rose to 99.99% as compared to 99.6% and 97% during 2006 and 2005 respectively. This increase may be attributed to the increased SMP during 2006 and 2007 that led importers into injecting energy in the System, and be paid to the increased SMP, rather than contracting with retail consumers, as it happened during 2005.

The following steps were taken towards the opening of the retail market:

- Following the Directive 2003/54 EC and according to the provisions of Law 3426/2005, all electricity consumers, except for those with specific provisions regarding the non-interconnected islands, are considered as eligible as of July 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 the part concerning power quality. Development work by RAE on the Network Operation Code continued throughout the reporting period.

- PPC was asked and did publish its retail tariffs unbundled per service provided; this revealed the approximate cost split between services, in an effort to eliminate distorted tariffs due to cross-subsidies. This, along with the definition of Public Service Obligations (PSO's) and their cost calculation (see below) are anticipated to lead to rational, cost-reflecting tariff structure

[2] The contract was signed in July 2008.

and enhanced competition. Also allowing an increase in tariff ceiling (by a total of 14% over a period of eighteen months) increased opportunities for new players to enter the market.

- After RAE's recommendation, the Minister of Development approved the Distribution Network charges that were not till that time defined, especially for the customers connected to the low voltage. The above decision facilitates the opening of the market, since all Suppliers are able to accurately calculate and structure their offers for potential customers.

- Ministerial Decision on Supply Code modification (YA Δ5/HΛ/B/Φ29/23860/30-11-2007). Following RAE's recommendation, the Minister of Development amended the Supply Code, by allowing customers connected to the high voltage grid to freely negotiate either with PPC or other suppliers their retail tariff. For as long as PPC retains more than 70% of the market, the tariffs are regulated; however, the high voltage customers are allowed to negotiate with PPC special clauses, especially related to their ability to offer interruptible load, and develop tailor-made tariffs adjusted to their special load profile. As a measure of protection of the customer, the decision also introduced a regulated cap tariff, to be designed by the Regulator, in case that no agreement between the customer and PPC is achieved.

- Finally, the same ministerial decision introduces a fuel charge mechanism, according to which, in case of sharp increases of the price of fuel oil and natural gas, fuel surcharge is calculated quarterly, to allow uncontrollable fuel cost to be passed to the final costumer. Nevertheless, the mechanism is designed in a way that only very high increases, that substantially downgrade the financial strength of PPC, are transferred to final customers.

<u>Unbundling</u>

Concerning unbundling of the distribution system operation, and according to Law 3426/2006, the respective organisational unit of PPC S.A. had to be transferred to the Hellenic Transmission System Operator (HTSO) by July 1st, 2007, which would then become a Transmission and Distribution System Operator (TDSO). The transfer of this PPC unit to the Transmission System Operator has not yet taken place; more details are presented in Section 3.1.4.

However, 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 already mentioned in last year's report, PPC S.A. had to 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 S.A. 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, and the reports for 2006 and 2007, especially the part of the unbundled accounts, are drafted with consistency according to the rules set, allowing for the comparison of all separate elements of the accounts for all available years.

Following the Ministerial Decision in November 2007, PPC is asked to publish its retail tariffs unbundled per service provided; at least four separate charges should appear on the electricity bill a) supply charge, b) distribution network charge c) transmission system charge and d) Public Service Obligation charge, plus the tax and RES levy charge. By separating the charges on the electricity bill, any future price increases will be allocated to the specific relevant service.

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 as public services: (a) supply of electricity to non-interconnected islands and to remote micro-grids with tariffs equal to those of the mainland interconnected system and (b) reduced tariffs for the supply of electricity to consumers / families with more than three children.

Following RAE's opinion, the Minister of Development in November 2007 approved the methodology for the calculation of the annual cost of the provision of Public Service Obligations, that is, the uniform end-user tariff application to all islands and discount on the tariff of large families. The methodology introduces a five-year regulatory period, where the year to year change is based on inflation and oil-price changes minus a required efficiency index. The full calculation of all end-user tariff elements is still to be done by PPC and approved by RAE.[3]

Because of the inclusion of the consumers on non-interconnected islands as public service obligations, the cost of PSOs becomes very high. For as long as PPC's accounts were bundled and there was no estimate of the actual PSOs size, the net cost of energy production and transmission could not be accurately estimated. The calculation of the PSOs size will contribute to the definition of a proper tariff structure and thus encourage private groups to enter the market enhancing competition.

2.2.2 Main developments in the natural 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, as well as dealing with matters concerning the implementation of the existing legislation. 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, important steps towards a liberalized market such as the establishment of the Hellenic Gas Transmission System Operator and the approval of the Standard Transportation Agreement, were taken during 2007. Moreover, important work on other pieces of secondary legislation such as the Network Code was undertaken by the Regulator and the new TSO.

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

1. Establishment of the Hellenic Gas Transmission System Operator in February 2007, under the name of "DESFA S.A.". DESFA is the owner and operator of the National Natural Gas System. DESFA is a 100% subsidiary of the vertically-integrated Public Gas Corporation (DEPA S.A.), which in turn is 65% state-owned and 35% owned by Hellenic Petroleum S.A.
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.

[3] The procedure was completed in July 2008 and RAE's opinion was provided to the Minister of Development.

3. Amendments to the TPA tariffs to the National Gas Transmission Network put into force in March 2006, in order to regulate potential competition problems among gas-fired power generators and their suppliers.
4. Completion of the balancing arrangements and approval of the annual balancing plan for the year 2008.
5. Interconnection with Turkey was completed in the second half of 2007, creating the potential for transit flows to Europe and enhancing security of supply for the Greek and other European gas markets.
6. Positive opinion by RAE and the Ministry of Development regarding the exemption by the Italian Authorities of the offshore part of the Italy-Greece Interconnector (IGI), according to the provisions of article 22 of the directive 2003/55/EC. The exemption was approved by the European Commission in June 2007. The companies are preparing an open season for the allocation of the non-exempt capacity to third-parties that will be carried out within 2008.
7. Applications by new gas suppliers for supply license in Greece, although none has been activated yet.
8. An increased interest of major international investors for gas transit through Greece.

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

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

Market Opening

Currently, gas-fired CHP-generators with annual consumption over 9 Mm^3 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).

Unbundling

The major development regarding unbundling of activities in the gas market was the establishment of DESFA, 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.

Furthermore, the three gas distribution companies are already preparing for the unbundling of their accounts, by setting the unbundling rules. The rules must be approved by RAE.

2.3 Major issues dealt with by the regulator

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

2.3.1 Electricity sector

RAE's work on the electricity market mainly focused on the following:

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. The weighted average of the units' multi-step bid cannot be less than the units' variable cost.
   - 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.[4]
2. Issue of RAE's opinion on details for the application of the Grid and Market Operation Code. RAE has expressed its opinion and issued decisions on several issues regarding the application of the new Grid and Market Operation Code, a number of which involving the calculation of market-related parameters and the description of methodologies to be applied in the context of the market operation. Moreover RAE issued a Decision (no. 76/2007) on 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. RAE is preparing its proposal for the establishment of an ancillary services market, anticipated by early 2009.[5]
4. Throughout 2007, RAE worked on the development of the Distribution Network Operation Code and organized a public consultation on the technical and service quality parts of this document. RAE is continuing work on the Distribution Network Operation Code, in order to organize a public consultation on the entire content of the Code and to express its final opinion within 2008.[6]
5. 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

[4] At the time this Report was written, further extension, till January 2009, had been given for the full implementation of the Code.

[5] In summer of 2008, a proposal was developed by RAE for the establishment of a tertiary reserves market and is currently in public consultation.

[6] The Distribution Network Operation Code is in public consultation from July 16 to September 30, 2008.

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, expected to be completed in the summer of 2008, 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.

6. Installation of meters that record the electric energy quality provided to the consumers throughout the country, including the non-interconnected islands. This will give RAE the opportunity to identify the necessary improvements to the network, as well as help in the rational design of the regulatory framework for the distribution network.
7. Assisted by an expert advisor, RAE worked on the development of a greek electric power system simulator that includes planning, execution and settlement of the short-term wholesale market. This involves the implementation and evaluation of several versions of algorithms that solve the greek day-ahead electricity market clearing problem, for the purpose of identifying the most appropriate version for final adoption. The proposal of a methodological framework will assist RAE to evaluate instances and strategies for manipulation and monopolistic/oligopolistic gaming behavior of participants in the short-term electricity markets for energy, reserves and ancillary services as these markets evolve, as well as to assess the effectiveness of market rules in place and evaluate regulatory policy and market rule redesign, if necessary. The project will be concluded in 2008.

2.3.2 Natural Gas sector

RAE's work on the natural gas market mainly focused on the following:

1. In January 2007 the Minister of Development approved the Standard Transportation Agreement (STA) prepared by RAE in cooperation with DESFA, which establishes all the transitional provisions for third-party access (TPA) to the high-pressure grid. RAE granted its consenting opinion to the Minister of Development following a public consultation process. In particular, the STA includes the following parts:
    - The procedure for the conclusion of the transportation contract between DESFA and the users of the Transmission System (application, qualifications of the applicant, rejection or approval terms).
    - The content of the contract and in particular the duration, the services provided by DESFA, 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 preparation.
2. RAE prepared and granted its opinion to the Minister of Development for the amendment of the TPA tariffs to the NNGS. The 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). This reduces the uncertainty and allows for the creation of a level playing-field among gas-fired power generators and their suppliers.

3. In March 2007 and in view of the operation of the National Natural Gas System (NNGS) during the scheduled Revithoussa 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 from TPA provisions could be granted to the Italy-Greece Interconnector (IGI) project, according to the provisions of article 22 of the Gas Directive. In June 2007, RAE granted a revised opinion addressing the concerns expressed in the EU Decision SG-Greffe(2007)D/203046.
5. In June 2007, RAE approved the annual balancing plan which was prepared by DESFA according to the provisions of the Gas Law 3428/2005.
6. RAE worked intensively and is concluding its proposal on the regulation of transit flows through the NNGS.[7]

[7] The proposal was published on May 2008. Following consultation with all parties involved (DESFA and international investors) RAE will incorporate such proposal into the corresponding provisions of the Network Code, to be put in public consultation within 2008.

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 July 1st 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 SA.

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

Congestion on interconnections

During 2007 Greece was electrically interconnected with its northern neighbouring countries (Bulgaria, FYROM and Albania) and with Italy (submarine, 400 kV DC link, 500 MW rated capacity).[8] 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 had 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.

[8] Interconnection with Turkey at 150kW was also available, but as Turkey is not yet synchronized with UCTE "island" operation was required.

Interconnection congestion management

A set of auction 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 interconnections and directions as shown in Table 1.

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

Table 1. HTSO responsibility for congestion manegement on interconnections

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 a 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.

In Table 2 we summarize the results of the monthly explicit auctions for electricity imports to Greece during 2007, through all the 400 kV interconnections.

Month	Border	Auctioned Capacity MW	Product Hours	Allocated Capacity MW	Clearing Price		Number of Bidders	Number of Assignees
					€/MWh	€/MW		
JAN	BG	135		135	0.20	105.6	6	5
	FYROM	160	528	160	0.15	79.2	6	3
	AL	70		70	0.05	26.4	3	2
FEB	BG	135		135	2.99	2009.3	10	8
	FYROM	150	672	150	0.00	0.0	4	4
	AL	40		40	0.07	47.0	4	2
MAR	BG	163	743	163	14.13	10498.6	13	4
	BG	37	623	37	5.55	3457.7	8	2
	FYROM	150	743	150	4.07	3024.0	6	6
	AL	0						
APR	BG	90	720	90	5.10	3672.0	11	6
	BG	85	528	85	3.42	1805.8	11	7
	BG	50	408	50	2.58	1052.6	11	4
	BG	25	216	25	2.36	509.8	11	3
	FYROM	100	192	100	0.44	84.5	5	3
	AL	0						
MAY	BG	150		150	4.52	1952.6	8	8
	FYROM	70	432	70	1.49	643.7	6	5
	AL	0						
JUN	BG	295	720	295	8.49	6112.8	13	7
	FYROM	50	480	50	1.75	840.0	7	3
	AL	60	288	60	0.49	141.1	4	1
JUL	BG	285	744	285	8.20	6100.8	10	4
	FYROM	30	496	30	1.00	496.0	4	2
	AL	50	496	50	0.12	59.5	2	1
AUG	BG	285	744	285	8.20	6100.8	10	4
	FYROM	30	496	30	0.10	49.6	2	1
	AL	0						
SEP	BG	200	720	200	4.36	3139.2	6	4
	BG	50	576	50	1.50	864.0	3	1
	FYROM	30	480	30	0.03	14.4	2	2
	AL	0						
OCT	BG	100	744	100	3.10	2306.4	4	2
	BG	100	624	100	2.10	1310.4	5	2
	FYROM	30	624	30	0.50	312.0	2	2
	AL	0						
NOV	BG	160		160	3.15	2268.0	6	4
	FYROM	0	720					
	AL	0						
DEC	BG	200		200	2.51	1686.7	6	4
	FYROM	0	672					
	AL	0						

Table 2. Monthly explicit auction results for imports to Greece – Northern Interconnections

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.

Month	Product Definition	Border	NTC	Auctioned Capacity	Product Hours	Allocated Capacity	Clearing Price		Number of Bidders	Number of Assignees
			MW			MW	€/MWh	€/MW		
JAN - FEB SEP -DEC	LOW LOAD Period Weekdays & Saturday (22:00 - 06:00 CET) Sunday (00:00 – 24:00 CET)	IT	500	250	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	HIGH LOAD Period Weekdays & Saturday (06:00- 22:00 CET)	IT	500	100	1664	100	15.51	25808.6	16	8
		BG	100			0	-	-	0	0
		FYROM	100			0	-	-	1	0
		AL	200			0	-	-	2	0

Table 3. Annual explicit auction results for exports – All interconnections

Tables 3 and 4 summarize results of annual and monthly explicit auctions for exports from Greece through all the interconnections during 2007.

Month	Product Definition	Border	NTC	Auctioned Capacity	Product Hours	Allocated Capacity	Clearing Price		Number of Bidders	Number of Assignees
			MW			MW	€/MWh	€/MW		
APR	1/4-8/4 & 14/4-16/4 22:00 – 06:00 CET	IT	500	150	136	150	0.09	12.2	6	3
		BG	150			0			1	0
		FYROM	150			0			1	0
		AL	150			0			1	0
	9/4-13/4 & 23/4-30/4 22:00 – 06:00 CET	IT	500	150	120	150	0.09	10.8	6	2
		BG	150			0			1	0
		FYROM	0							
		AL	150			0			1	0
	17/4-22/4 22:00 – 06:00 CET	IT	500	150	64	150	0.09	5.8	7	3
		BG	150			0			1	0
		FYROM	150			0			1	0
		AL	0							
MAY	1/5-6/5 & 20/5-27/5 22:00 – 06:00 CET	IT	500	150	160	150	0.22	29.9	5	2
		BG	150			0			1	0
		FYROM	230			0			1	0
		AL	100			0			1	0
	28/5-31/5 22:00 – 06:00 CET	IT	0	150	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
	7/5-19/5 22:00 – 06:00 CET	IT	500	150	120	150	0.14	9.0	5	3
		BG	0							
		FYROM	0							
		AL	0							

Table 4. Monthly explicit auction results for exports – All interconnections

As it may be observed from Tables 3 and 4, during 2007 long-term firm (annual, monthly) capacity rights were not auctioned for a significant percentage of time and capacity. This is due to HTSO´s concerns about the security of supply of the Greek system. These concerns arise from special circumstances (very low hydro reserves, LNG-facility planned outage) impacting available generation to serve the load. In principle, interconnection capacity has been made available for exports mostly during low-load periods (22:00 – 06:00 CET) and Sundays. RAE approved the HTSO's proposal so as not to endanger greek security of supply, especially since similar action is taken by neighbouring EU-member states.

RAE acknowledges that such practice has to be checked against the relevant provisions of the Regulation 1228/03. However, RAE believes that in the issue concerning cross-border trade, all parties involved should demonstrate their strong commitment in complying with Reg.1228/03 and improving market conditions, by maximising the available interconnection capacity.

Internal Transmission System 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 congestion, especially in periods of high demand. According to the provisions of the 2005 Grid Code, such constraints are integrated in the daily electricity wholesale market (applicable by January 2009). In general, when the unconstrained Day-Ahead schedule obtained through the wholesale market, violates physical flow rules (mainly due to voltage stability limits and thermal limits), the market is split; i.e., two different (zonal) System Marginal Prices are calculated for Generators. Concerning Suppliers, one uniform SMP is determined, as the weighted average of the two 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 component of the Transmission System Use tariff for generators (more details in Section 3.1.3).

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

With respect to other information relevant to anticipating the congestion of the national system (internal and on interconnections), HTSO currently provides the market with forecasts (D-1) 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.

As already mentioned, RAE issued in April 2007 Decision 76/2007 elaborating on 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 should 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

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.

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.

HTSO compliance in this respect is deemed satisfactory. By the end of 2007, all information that is critical to the day-to-day operation of the market, both ex-ante and ex-post, is published in a satisfactory timeframe. Further improvement will be sought with regard to publication in a systematic way of scheduled and non-scheduled unavailability of transmission and generation infrastructure and on the publication format.

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 (DAES). 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 December 31st 2007 however, only imports were scheduled at D-1 on the basis of their priced energy offer; exports were scheduled on the basis of firm nominations submitted at D-2 (non-priced load declarations), and priority was given to transactions that are associated with allocated transmission rights.

According to the **2001 Grid Code,** congestion revenue was 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 stipulated that congestion revenues were 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. Revenue 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 became effective on January 1st 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 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 Independent System Operator with no transmission assets). In fact, it appears that the 2006 profit published by HTSO which is subject to taxation and distribution to stockholders – i.e., the government and the PPC SA -- includes revenues accumulated from interconnection capacity allocation in previous years. RAE has taken all necessary action to safeguard that this will not happen again and to find appropriate resolution for the past incident.

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

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

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

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

For the non-interconnected islands, the operator of the relevant network (a different department of PPC S.A.) 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. Concerning the Distribution Networks, it is envisaged that the following issues will be covered (since the Distribution Network Code has not been approved yet):

- methodology for calculating network tariffs (connection and use),
- performance measurement and quality regulation,
- provision of information by the network operators to the interested parties.
- definition of regulatory periods during which the following aspects of DSO activities are set in advance:

- the reference annual revenue of the network owner
- the overall (strategic) network development plan, focusing mainly on major network extensions and advances in network monitoring, control and metering
- quality regulation (service quality targets, penalty/reward levels)

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 undertook development work throughout the reporting period and is planning to start the relevant consultation procedure in summer of 2008. According to this time schedule, RAE expects that the Distribution Network Code should be enforced by the end of 2008. Until then, PPC, as the distribution network owner and operator, follows internally-defined rules and procedures.

Transmission Network Tariffs

Network tariffs are calculated on the basis of the annual system cost, which is defined as the sum of the annual rent 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) South, where 2% of the annual Transmission System cost is allocated to Generators, and (b) the rest of the interconnected system, where 15% of the annual Transmission System cost is allocated to Generators.

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 II.

The transmission network tariffs for 2007, as approved by the Minister of Development after the opinion of RAE, are as follows:

- Suppliers: € 22,499 MW/Year
- Generators in southern Greece € 496 MW/Year
- Generators in northern Greece € 6,110 MW/Year.

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 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 rent owed by HTSO to PPC SA and the annual operating cost of the System, as well as the calculation of the use of system charges, as performed by the HTSO.

Distribution Network Tariffs

Legal unbundling of the operation of the distribution network has not yet been established. Moreover, 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.

RAE, taking into account the progress achieved in 2005 – 2006 with the unbundling of the accounts of PPC, formulated its opinion for the distribution network charges that were finally approved by the Minister of Development for the year 2007. The regulated Distribution Network Revenue for 2007 was calculated on the basis of the methodology that is applied also to the calculation of the Transmission System Revenue, using figures from the unbundled accounts for 2006 which were issued by PPC in accordance to RAE guidelines. The relevant consumer charges were calculated taking into consideration the main consumer categories of the network with respect to supply voltage level and billing parameters (energy, demand, reactive power).

Approved Distribution Use of System Charges for 2007 are presented in Table 5.

Consumer Category	**Fixed DUoS Unit Charge** (€ per MVA of subscribed demand per year)	**Variable DUoS Unit Charge** (€/MWh)
Medium Voltage Consumer	4800	2.8
Low Voltage Consumer		
Energy (active & reactive) & Demand Billing	2740	14.0
Energy (active) & Demand Billing	2830	16.1
Domestic Consumers	1210	16.1
Other (non-domestic) consumers – Energy (active) Billing only	1520	16.1

Table 5. Approved Distribution Use of System Charges for 2007

Estimated national average network charges

According to RAE's calculations, the average cost of transmission (based on the total energy consumption) on the Interconnected Transmission System in 2007 is 4.65 € / MWh.

Given the 15%-85% G – L split, this cost led to:

- average G charge = 0.70 €/MWh.
- average L charge = 3.95 €/MW/h.

Tariffication for transmission charges, which is currently based only on capacity, is under review (introduction of capacity and energy charges in order to accommodate the various types of consumers and metering/billing capabilities). As a result of transmission charges being only capacity related, in some consumers' categories, especially those with very low load factor, the reported charge per MWh seems to be very high.

Estimates of average network charges for typical consumers are given in the next table.

Typical Customer	Transmission Network		Distribution Network
	Annual Charge (€/year)	Unit Annual Charge (€/MWh)	Annual Charge (€)
Ib	1124	22.50	(a) 893 (b) 971 (c) 920
Ig	89996	3.75	95632
Dc	14.74	4.21	66.00

Ib: commercial customer with annual consumption of 50 MWh/year and maximum demand 50 KW. For distribution network, a LV customer, with a contracted demand of 58 kVA is considered, where:
(a) is for active energy billing,
(b) is for demand & active energy billing,
(c) is for demand & active-reactive energy billing with an average load factor of 0.92.

Ig: industrial customer with annual consumption of 24 GWh/year, with maximum demand 4000 KW. For distribution network, a MV customer, with a contracted demand of 4705 kVA and an average load factor of 0.92 is considered.

Dc: household customer with annual consumption of 3500 KWh/year, of which 1300 KWh charged according to the night tariff. For distribution network, a LV customer, single phase, with a contracted demand of 8 kVA is considered.

Table 6. Estimates of average electricity network charges for typical consumers

It must be noted that there was no separation of charges in retail supply tariffs during 2007.

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 yet 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 so far for the formal evaluation of the quality of service offered either by the Transmission or the Distribution system operators.

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 may 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.

No legal obligations are imposed on the DSO for the publication of data, since neither the Distribution Network Code nor the terms for the Licence of the DSO were available during 2007.

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, since it is considered that the current stage of development of the electricity market, especially regarding the competition on the supply side, does not allow for the establishment of a properly functioning, efficient balancing market. This concept may be reconsidered in the future, should the market evolution and conditions permit.

The administrative balancing arrangements are closely linked to the operation of the mandatory Day Ahead Market, which 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 III.

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 may 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 may be revised up to 5 times prior to gate closure. Revisions are not allowed following gate closure.

Provision of information

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.

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.

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.

Following (ex-post) the Dispatch Day, the HTSO provides market participants with the following information:

- Actual Hourly System Load.
- 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.

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

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 Law 3426/2005, PPC's staff seconded to the HTSO is under the obligation to choose, either to be return to PPC or to remain with HTSO by resigning from PPC. It has to be noted that PPC occupies approx. 1700 employees in the Transmission Network business. All maintenance and expansion works, decided and planned by the HTSO, are executed under PPC´s responsibility, as the owner of the transmission network.

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. RAE would like to remind that the Commission had in the past questioned the greek arrangements regarding the unbundling efforts, and more specifically whether they are in accordance with Directive 54/2003/EC; however, no further action was taken.

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. According to the same Law, this unit had to be transferred to the HTSO by July 1st 2007, and the HTSO would be assigned not later than July 1st 2007 the additional role of the Distribution Network Operator.

PPC would retain ownership of the (distribution) Network and per Article 11 of Law 3426/2005, would continue to receive applications for connection to the network, to 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 would 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, would 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 would be working in the DSO is not fixed 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, under its Distr. Network ownership role.

The foreseen transfer of staff and responsibilities according to the provisions of the Law has not taken place within 2007. This is partly due to the fact that the Distribution Network Code was not in place by July 2007. Moreover, in its effort to develop the Distribution Network Code and to define in particular the tasks, the procedures and the business relationship between the Network Operator and the Network Owner, RAE has identified certain inefficiencies and practical issues arising from the allocation to two entities (Operator and Owner) of duties and responsibilities that are complementary and/or interrelated, as foreseen by current legislation. RAE intends to highlight its findings on this matter and to open the relevant discussion among concerned parties within the public consultation process for the DNO Code.[9]

Unbundling of accounts

As mentioned in last year's 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 may only be modified following

[9] On July 16 2008 the Distribution Network Code was put on public consultation till September 30 2008.

RAE's approval. The wording of the abovementioned provision which provided that RAE is responsible for approving any modification to these rules, lead to a 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. It was amended by Law 3426/2005, which clearly assigns to RAE the authority to cooperate and approve the methodology used for the unbundling of accounts of vertically integrated undertakings.

PPC S.A. has already submitted unbundled accounts for the recent years. Thus, and in view of the assessment of the accounts submitted by PPC, RAE had to approve again 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 principle rules and methodology with its decision no. 86/2007.

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.

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 may impose fines pursuant to article 33 of Law 2773/1999.

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 four private industrial groups are proceeding with the installation of CCGT units of total capacity in the order of 1700 MW, to be completed by the end of the decade, as well as of a 330 MW CHP plant expected to be in operation in the summer of 2008. 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 in 2006 and practically stopped in 2007, since the consumers importing energy found it more profitable to return to the regulated tariffs and sell the imported energy to 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 2007 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 III for a brief description). Bids submitted by generators should be higher or equal to the respective short-run marginal cost, and a uniform upper limit of 150 €/MWh for 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 2007 total consumption of **56.4 TWh** (including losses) and a load peak of **10610 MW** (plus an additional 500 MW of curtailed load) have been measured in the interconnected System, which refers to the mainland of Greece (interconnected islands not included). The fuel mix for 2007 is shown in Table 7 and Figure 1.

PLANT TYPE	GWh Produced	%
Thermal – brown coal (Lignite)	31092.9	55.15
Thermal – Gas	13211.4	23.43
Thermal – Oil	3262.0	5.79
Hydro – storage (includes pumping)	3142.7	5.57
Other RES	1312.1	2.33
Net Imports	4354.2	7.72
Total	**54586.9**	**100.00**

Table 7. Fuel mix in the mainland system as of 31.12.07

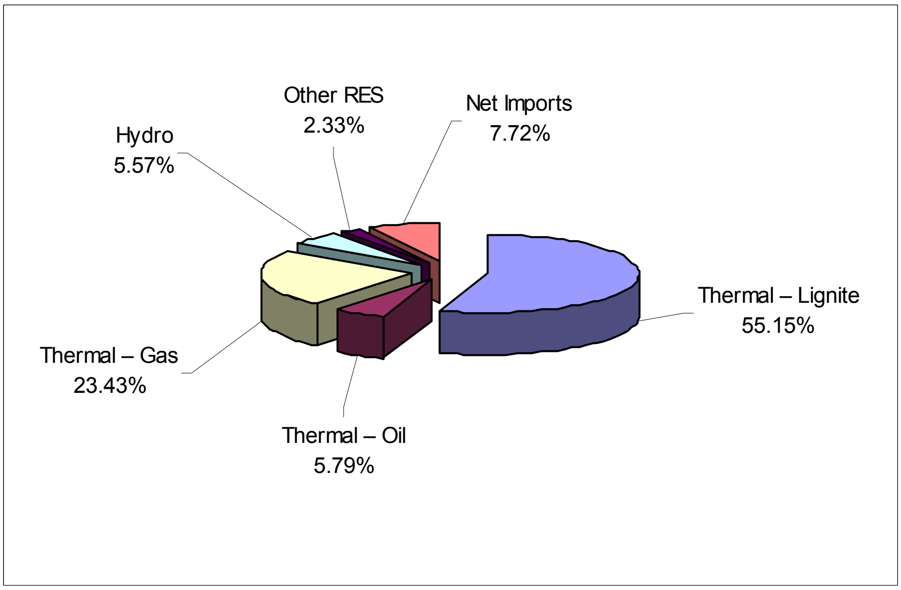

Figure 1. Electricity production by plant type in the interconnected system

The total sum of NTC for import is calculated at 650 MW. Thus the degree of Network interconnection is approximately 5.2%. For the reported period the sum of physical imports was 6.411 TWh, while the corresponding figure for exports was 2.057 TWh.

In 31.12.2007 the total maximum net generation capacity on the mainland interconnected system was 12451.9 MW, distributed as follows:

PLANT TYPE	Gross Installed Capacity (MW)	Net Installed Capacity (MW)
Lignite	5288.0	4808.1
HFO	750.0	718.0
CCGT	2010.3	1962.1
Natural gas - other	507.8	486.8
Hydro plants	3016.5	3016.5
RES and small cogeneration	769.7	769.7
Other cogeneration	109.7	109.7
Total	**12542.0**	**11870.9**

Table 8. Installed capacity in the mainland system (as of 31.12.2007)

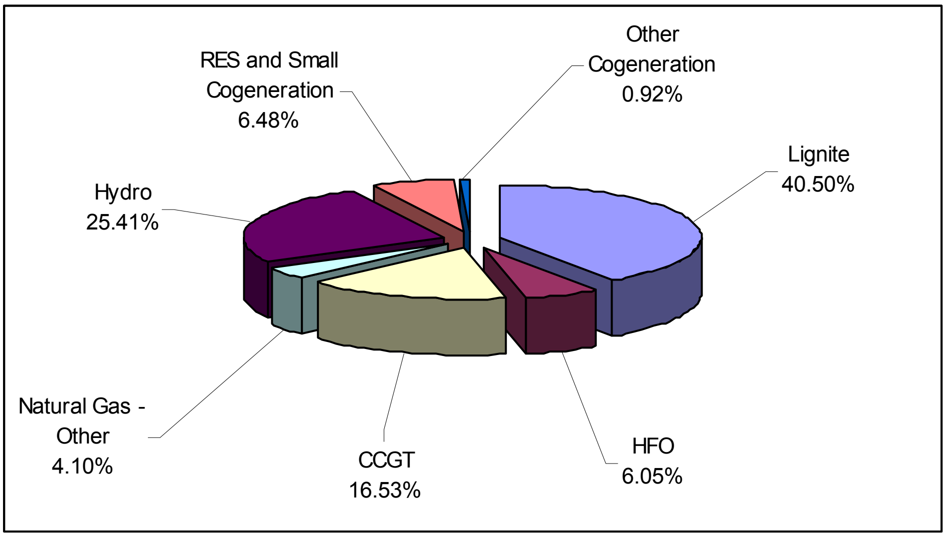

Figure 2. Net installed capacity per plant type

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, natural gas, oil and large-hydro)*. Its competitors (T-Power, IRON) hold the remaining 4.7%. If we also consider the RES and small cogeneration not owned by PPC (but also not participating in the competitive wholesale market), then its market share falls to around 90%.

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

Table 9. Total installed capacity and dominant utility's market share.

Company	Capacity (MW)	Year of Commissioning	Unit Type
T-Power S.A.	390	2005	CCGT (single shaft)
IRON S.A.	148	2004	Gas Turbine

Table 10. Thermal generating capacity owned by IPPs

From the above, it is concluded that the proportion of installed capacity owned and the net generation volume produced by the **largest three** companies is equal to 100% and 96.8% respectively[10]. Still, only PPC holds more than a 95% share of both installed net generating capacity and net generation volume, since the installed net generating capacity of the two IPP's was 538 MW (4.64% of total installed net capacity), while their net generation volume (which are both natural gas units) was 2103.6 GWh (3.85% of total net generation).

Due to the aforementioned market share of PPC S.A. in terms of generating capacity and volume in the mainland (interconnected) system, the HHI index is estimated close to the upper bound of 10,000.

The market for ancillary services:

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.

The volume of electricity traded:

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. The active traders in the pool are PPC, T-Power, IRON, as well as thirteen companies who are active strictly as importers and/or exporters.

Demand-side participation in the wholesale market

There is no formal demand side participation in the wholesale market in Greece. Demand's involvement to the market is minimal and may only be affected indirectly, through the minimization of the use of electricity by a limited number of industrial customers during peak hours, when the price of

10 Please note that we always refer to the companies participating in the market, thus excluding RES and small cogeneration.

electricity is high. Nevertheless, although these measures do reveal some elasticity of the consumers to the high prices during peak hours, in general they are considered as adequacy-of-supply measures.

Integration with neighbour member-states:

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, imported from the Balkans region. The price differentiation between the Balkans (rough estimate of 50 €/MWh) and Greece (wholesale price from the daily market is around 64.94 €/MWh) and Italy (70.99 €/MWh) creates favourable conditions for electricity trading. Nevertheless, trading arrangements over the interconnections were not sufficient to enhance trading activity during 2007.

Mergers and aquisitions:

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

Tables 11 and 12 present the consumption of final customers in 2007 broken down by sector and connection voltage, for the interconnected system and the non-interconnected islands respectively. Total consumption was 61.3 TWh, 99.99% of which was supplied by PPC, with a very small amount (511.52 MWh, i.e., less than 0.01% for the interconnected system) being supplied by Heron SA.

Up to today, except for PPC SA, supply licenses have been granted to 26 other companies. None of these companies are affiliated to the HTSO or DSO businesses. It should be noted that most suppliers are active in trading rather than retail supply. The licensed suppliers are listed in Annex IV.

Voltage level	Net consumption (GWh)							Losses (GWh)	Total
	Residential	Industrial	Commercial	Agricultural	Public sector	Traction	Mines & pumping		
Low	16235.0	1315.4	9949.1	2259.9	1496.1	0	n.a.	2616.8	**33872.3**
Medium	0	5821.1	3703.2	376.9	942.1	142.0	n.a.	332.8	**11318.1**
High	0	7761.7	0	0	0	0	2189.5	1231	**11182.2**
Total	**16235.0**	**14898.2**	**13652.3**	**2636.8**	**2438.2**	**142.0**	**2189.5**	**4180.6**	**56372.6**

Table 11. Electricity consumption in the interconnected system

Voltage level	Net consumption (GWh)							Losses (GWh)	Total
	Residential	Industrial	Commercial	Agricultural	Public sector	Traction	Mines & pumping		
Low	1722.3	123.8	1667.9	211.8	279.9	0	n.a.	n.a.	**4005.6**
Medium	0	207.7	556.0	32.7	179.2	0	n.a.	n.a.	**975.5**
Total	**1722.3**	**331.5**	**2223.9**	**244.5**	**459.1**	**0**	**n.a.**	**n.a.**	**4981.2**

Table 12. Net electricity consumption in the non-interconnected islands

In 2007, the amount of electricity supplied by suppliers other than PPC S.A. was insignificant. This volume presents a decrease compared to previous years, due to the fact that certain customers that in the past purchased electricity in the competitive retail market switched back to the regulated retail tariffs offered by PPC. These prices are more attractive to customers compared to prices available in the competitive market, because regulated retail prices have not increased to the extent necessary to cover increases in fuel prices and resulting increases in generation costs. This is a distortion which has hindered the development of competition in the retail market in Greece.

Another significant barrier to the development of competition in the retail market is the fact that the retail tariffs have not yet been unbundled and there are no explicit charges for the use of the transmission and distribution systems for the customers connected to MV and LV networks. In order to remove this barrier, during 2007 RAE proposed (and the Minister approved) a transitional methodology and charges for the use of the distribution system (see Section 3.1.3) which is in place until the Distribution Code (including methodology for setting DUoS) is in place (planned for the end of 2008).

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.

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 signed 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 October 1st, 2005.

Retail Price Levels

Given the significant market share of PPC in the Greek retail electricity market (above 70% as stipulated in the Supply Code), retail tariffs are regulated. Tariffs are set by decision of the Minister of Development, following an opinion by RAE. In November 2007, the Minister of Development issued a decision regarding the regulation of the tariffs for customers connected to the high voltage network. HV customer retail tariffs cease to be regulated as of July 1st 2008. The Ministry will then set a maximum level for the HV tariffs, following an opinion by RAE.

As mentioned earlier, the underlying costs of supplying electricity to retail customers have been increasing while regulated retail tariffs have not been allowed to increase at similar rates. For example, during the period between 2004 and 2007, PPC fuel costs increased by 87%, cumulative inflation was around 9% whereas average retail electricity tariffs increased in total by 15%. In order to move to more cost reflective levels, three price increases were implemented in 2007, in April, July and December (although not always being applied to all tariffs).

As a result, the average level of the (all inclusive) regulated PPC tariff for industrial consumers in 2007 was 0.05 €/kWh for high voltage industrial customers, 0.068 €/kWh for medium voltage and 0.103 €/kWh for low voltage. The average price for commercial customers was 0.086 €/kWh for medium voltage and 0.12 €/kWh for low voltage. Finally, average revenue from domestic customers was 0.092 €/kWh, with energy charges in December 2007 ranging from 0.072 to 0.179 €/kWh depending on the consumption level.

Retail tariffs are still bundled and include all elements (wholesale, transmission, distribution, supply margin and levies). Only the RES levy and VAT (9%) currently appear separately on customer bills. All necessary actions for the unbundling of the tariffs have been scheduled to take place during 2008 and therefore tariffs are expected to be fully unbundled from 1 January 2009. Since the unbundling of the retail tariffs is not yet complete, 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, levies and taxes.

In November 2007, the Minister approved a further price increase of 10% for HV tariffs, an average 7% increase for MV and LV tariffs to take effect on 1 July 2008, and the introduction of an automatic tariff adjustment mechanism from January 2009 to reflect fuel price fluctuations. These changes, combined with the unbundling of the tariff elements, aim to remove the current distortions of cross-subsidies between consumer categories and result in fully cost-reflective levels which will promote the development of healthy competition in the retail electricity market.

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

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 S.A.. 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, as well as the LNG Terminal on Revithoussa Island.

No major developments were recorded in the supply of natural gas. The incumbent company, DEPA, remains the only gas importer and supplier of large customers (consumption over 9 Mm^3/year), power producers, and the local distribution companies (EPA). In distribution, the three EPA companies (which operate in the areas of Attica, Thessaloniki and Thessaly), remain the only suppliers of domestic, commercial and industrial customers, each being a monopoly in its area of operation. DEPA holds 51% of the shares in EPA's, through its 100% subsidiary Gas Distribution Company, EDA S.A., while private investors hold 49% and exercise the management. EDA S.A. was established in January 2007, also following the implementation of law 3428/2005. DEPA is in the process of establishing three new Gas Supply Companies, which will cover the areas of Central Greece, Central Macedonia (excluding Thessaloniki) as well as Eastern Macedonia and Thrace. The process of preparing the international tenders is already underway, aiming to invite the participation of private investors for the setting up of new companies.

Figure 3 depicts the current ownership status of all the companies involved in the natural gas market.

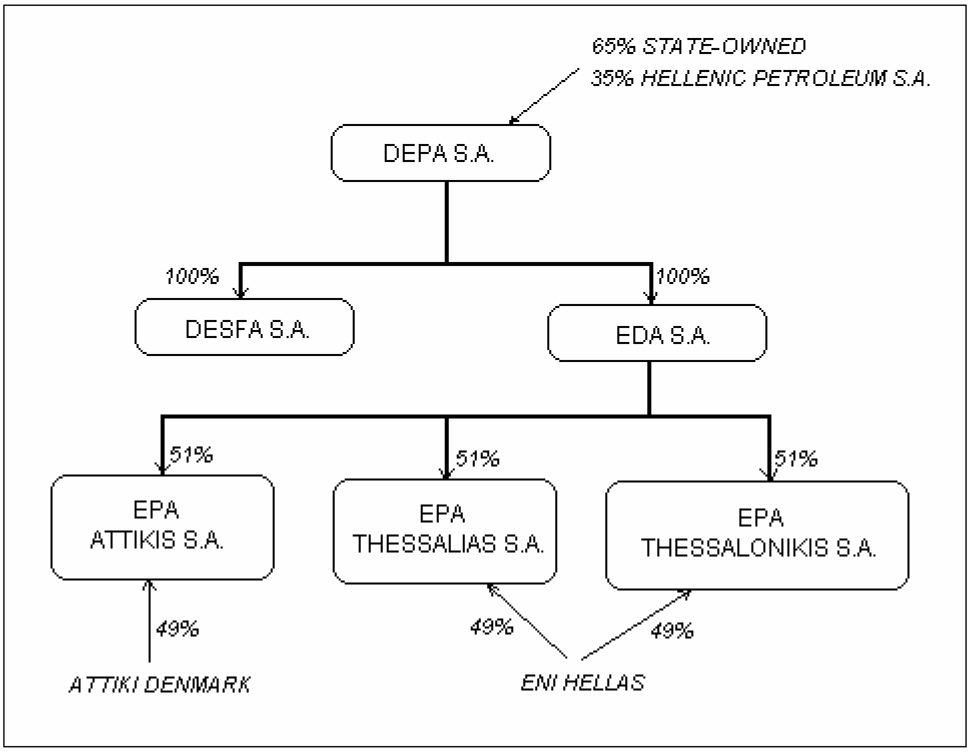

Figure 3. Ownership status of the companies in the natural gas market.

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 at the latest within three years after the expiry of the derogation period (i.e. November 2009), subject to the milestones set therein. In addition, existing 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 Mm^3/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 these 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 Gas Law has come into force will also be eligible customers by the date of their incorporation.

Currently, eligible customers represent approximately 73.5% of the total gas demand in Greece, based on the actual 2007 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

For the time being, the main interconnection of the Greek NGS is the one 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 the Bulgarian national network. This is also the case for the transit pipelines upstream of Bulgaria.

The new interconnection with Turkey became operational at the end of 2007. The capacity of this new interconnection, which is greatly dependent upon the technical capacity of the Turkish system, is expected to rise gradually within the next few years. 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 at 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 Gm^3/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 has been assigned the responsibility of monitoring and supervising the actual application of such rules, in cooperation with the other 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

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 DESFA and a public consultation. Actual tariffs will be set on the basis of the Tariff Regulation by DESFA 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 DESFA 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), provision has been made to recover 95% of the required revenue for the LNG terminal through the transmission tariff applied for natural gas transportation via the high-pressure pipeline running through mainland Greece, while 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	

Table 13. Natural gas transmission tariff coefficients

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	

Table 14. Natural gas tariff coefficients

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.

Two Ministerial Decisions amended the tariff MD 4955/2006:

i. 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.

ii. 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 their 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 follows a different methodology in order to calculate its 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

Table 15. Natural gas national average network charges

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- 31.12.07
D3	15.15
I1	14.44

Table 16. Indicative charge for transmission and distribution of Natural Gas in the Thessaloniki area

D. Storage charges

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

Balancing

As already mentioned, in June 2007 RAE approved the annual balancing plan, elaborated by DESFA, for year 2008. Responsible for the balancing of the natural gas system is DESFA, which is delegated, by law, to enter into contracts with natural gas suppliers in order to obtain the necessary quantities of gas. According to the balancing plan and in line with the provisions of Gas Law 3428/2005, the necessary quantities of gas will be acquired from DEPA – specifically, DEPA will supply DESFA with LNG quantities. 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 S.A.”. 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 Revithoussa 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 January 31st of each year, DESFA 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 DESFA. On the basis of that report, RAE shall evaluate annually the extent of independence of DESFA 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 S.A., the Greek incumbent, has not published unbundled accounts as yet. The gas distribution companies (EPAs) are preparing for the accounting unbundling process and are expected to publish unbundled account for the financial year 2008. For this purpose, during 2007 the distribution companies prepared the rules for accounting unbundling.

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

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

5 Security of Supply

5.1 Electricity [Article 4]

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.

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

Table 17. Energy and peak power demand for the interconnected system

Forecasts for energy and peak power demand for the years 2008-2012 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 according to 3 scenarios, as shown in the following tables: a reference, a low-demand and a high-demand scenario. During the recent years it has been observed that the yearly rate of demand increase is slightly lower than the yearly rate of increase of the country's GDP. The reference scenario was calculated assuming a continuation of the previous years' trend, based on a conservative forecast for the GDP increase. The high-demand scenario assumes an optimistic rate of increase for the GDP, while the low-demand scenario assumes that the rate of demand increase remains the same as that of the last 3 years (2.5%).

	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)
2007	55254			55254			55254		
2008	56635	2.5	1381	56910	3.0	1656	57190	3.5	1936
2009	58050	2.5	1415	58620	3.0	1710	59190	3.5	2000
2010	59500	2.5	1450	60380	3.0	1760	61260	3.5	2070
2011	60990	2.5	1490	62190	3.0	1810	63400	3.5	2140
2012	62520	2.5	1530	64050	3.0	1860	65620	3.5	2220

Table 18. HTSO scenaria / forecasts for yearly energy demand in the interconnected system

Year	Low (MW)	Reference (MW)	High (MW)
2008	10420	10900	11580
2009	10660	11150	11840
2010	10910	11400	12110
2011	11150	11660	12380
2012	11400	11900	12640

Table 19. HTSO scenaria / forecasts for yearly peak demand in the interconnected system

5.1.2 Generation Capacity and Licensing

On 31.12.2007 the total 11989.4 MW of total net generation capacity in the interconnected system was distributed as follows:

Plant type	Net installed capacity (MW)	%
Lignite	4808.1	40.10
HFO	718.0	5.99
GTCC	1962.1	16.37
Natural gas - other	486.8	4.06
Hydro plants	3016.5	25.16
RES and small Cogeneration	889.9	7.42
Other Cogeneration	108.0	0.90

Table 20. Installed capacity as of 31.12.2007 in the interconnected system

<u>Licensing & Tenders for new capacity in the interconnected system</u>

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; four private industrial groups have announced their intention to install CCGT units, of total capacity in the order of 1700 MW, before the end of the decade.

Furthermore, interest for developing plants has appeared: three applications for generation license concerning approximately 1600 MW of total capacity have been submitted to the Regulator during 2007.

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.[11]

Concerning RES, the situation is presented in the following Table. By 31.12.2007, the RES capacity installed amounted to approximately 867 MW (large hydro not included).

RES TYPE	COMMERCIALLY OPERATING		WITH INSTALLATION LICENSE		WITH GENERATION LICENSE		RECALLED		APPLICATIONS FOR GENERATION LICENSE	
	MW	%	MW	%	MW	%	MW	%	MW	%
WIND	734.0	84.6	946.7	88.0	6481.5	90.5	544.6	81.6	34125.6	86.5
BIOMASS	32.1	3.7	22.3	2.1	94.8	1.3	24.5	3.7	451.6	1.1
GEOTHERMAL	0.0	0.0	0.0	0.0	8.0	0.1	0.0	0.0	335.5	0.9
SMALL HYDRO	100.2	11.6	105.5	9.8	512.5	7.2	98.0	14.7	1883.5	4.8
PVs	0.8	0.1	0.9	0.1	67.7	0.9	0.1	0.0	2668.6	6.8
TOTAL	**867.1**	**100.0**	**1075.4**	**100.0**	**7164.5**	**100.0**	**667.3**	**100.0**	**39464.8**	**100.0**

Table 21. Licensed RES plants as of 31.12.2007

For the interconnected system, the fuel-mix situation during the last 3 years is as follows:

[11] In July 2008 the respective contract was signed between HTSO and the successful bidder.

	2005		2006		2007	
	GWh	%	GWh	%	GWh	%
Lignite	32056.6	60.0	29165.2	53.43	31092.9	55.15
Fuel Oil	3302.2	6.2	3309.1	6.06	3262.0	5.79
Natural Gas	7944.6	14.9	10169.1	18.63	13211.4	23.43
Large Hydro	5420.6	10.2	6229.4	11.41	3142.7	5.57
RES	894.8	1.7	1511.7	2.77	1312.1	2.33
Net Imports	3780.9	7.1	4202.4	7.70	4354.2	7.72
Total	**53399.7**	**100.0**	**54586.9**	**100.00**	**56375.3**	**100.00**

Table 22. Generation Fuel Mix 2005-2007 ***(Source: HTSO)***

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

Non-interconnected islands

Each of the non-interconnected islands is supplied by a small autonomous power system. Therefore, a synchronised peak-demand cannot be calculated since the load profiles are quite different between the islands.

As shown in the following tables, on these islands 90% of the electricity is produced by HFO and LFO units. More specifically, a total of 760,000tn of mazut and 523,000m^3 of diesel were consumed in these power plants in 2007, adding up to a cost of 525 million €. The percentage of RES (mainly wind) on the islands, 9.73%, is worth noting. More than 99% of the RES installed capacity on the islands comes from wind plants.

Plant Type	GWh produced	%
Thermal – diesel & mazut	5004.9	90.27
RES	539.7	9.73
Total	**5544.6**	**100.00**

Table 23. Electricity production by plant type on the non-interconnected islands

Plant type	Net installed capacity (MW)
Thermal (Diesel & Mazut)	1588.4
RES (mainly Wind)	218.6
Total	**1807.0**

Table 24. Installed capacity as of 31.12.2007 on the non-interconnected islands

PPC S.A. is the only supplier and generator (with the exception of RES, CHP and autoproducers) on these islands (see Section 3.1).

The electricity production cost of these small thermal plants is very high, especially after the recent increase of oil prices. However, as a measure to promote social cohesion, consumers located on non-interconnected islands enjoy electricity supply service at the same tariffs as any other customer regardless of the cost of their connection and supply (regulated tariffs). 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. According to preliminary calculations of the PPC (not yet approved by RAE), the PSO cost amounts to 442 million € for 2007.

A secure way to reduce the additional cost for the supplying the non interconnected islands is their interconnection with the mainland system. National Technical University of Athens carried out a study on behalf of RAE about the technical and economic feasibility of interconnecting the islands with each other and with the mainland system. The study showed that there are no serious technical problems against the project. Although the estimated cost is high (2-3 billion €), it may be amortized within a few years and the benefits, apart from lower electricity prices for all consumers in the country in the long-run, are expected to be manifold:

- increased security of supply in the long-run. Note that most of these islands are tourist attractions, where the inhabitants often object to the construction of new polluting plants, although the demand for electricity increases fast over the last years.
- improvement of the quality of the supplied electricity over the small and usually old autonomous plants
- reduction of GHG emissions
- decrease of the country's dependence on oil, which becomes more important with the continuous rise of oil price
- further exploitation of excellent RES potential (especially wind) of islands.

RAE will further assess the results of the study in 2008.

5.1.3 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 (e.g., 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 environmental effects, and the rest of the economy are studied using specific analytical models.

5.1.4 Incentives to build capacity

The 2005 *Grid and Market Operation Code* 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 may 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 may 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.

5.1.5 Transmission system development

According to the Grid & Market Operation Code, HTSO is responsible for the development of the transmission system on the mainland and the interconnected with this system islands. The set of criteria applied by the HTSO in planning the development of the transmission system aim to achieving, at all times, the transmission of electricity in a secure, reliable and most economic manner, applying transparent, unbiased and non-discriminatory criteria, while taking into account the principle of providing access to anyone wishing to connect to the transmission system[12]. Critical parameters are the foreseen power demand, new generation in the system, and the interconnection needs with other systems. In this framework, HTSO elaborates and publishes annually the five-year plan for the development of the interconnected transmission system (Transmission System Development Study – TSDS), 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 TSDS 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, 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 may undertake this project.

The projects that refer to extensions of the transmission system in order to connect new facilities, may 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 using scenarios with forecast demand over a 5-year period, in order to assess the ability of the system to serve the expected load, to identify potential weak points, and to determine the necessary system development to secure reliable and economic operation. Additionally, a market splitting mechanism will be introduced in the Day Ahead Dispatch Schedule on January 1st 2009, according to the Grid & Market Operation Code. This mechanism, based on a two-operational zone consideration of the Greek System, is expected to provide an accurate evaluation of the cost of internal congestions.

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[12] 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 with regard to the necessary system reinforcements

Major projects planned for the following years according to TSDS are:

- Expansion of the 400 kV system to the northeast part of the interconnected system for the interconnection of the Turkish system with Greece (more details in the next section), as well as accommodation of generation by wind parks and new thermal power stations. The full project will be in operation by year 2009.
- Expansion of the 400 kV system to the south part of the interconnected system. Three new EHV substations will be erected for this purpose in the Peloponnesus area. By year 2012, a large part of this project is expected to be in operation. The reinforcement of this area will provide increased security as well as additional transmission capacity for new RES in Peloponnesus.
- Connection of the Cyclades islands with the interconnected system through a DC or AC submarine link. Aim of this project is not only reduced PSO charges for the supply of these islands but also transfer of power from wind parks to the interconnected system. The project is planned to commence in year 2010. Figure 4 graphically shows the existing and planned connections of Cyclades. The connections of the islands of Andros and Tinos to the interconnected island of Evia already exist; the other islands are powered by small autonomous systems.

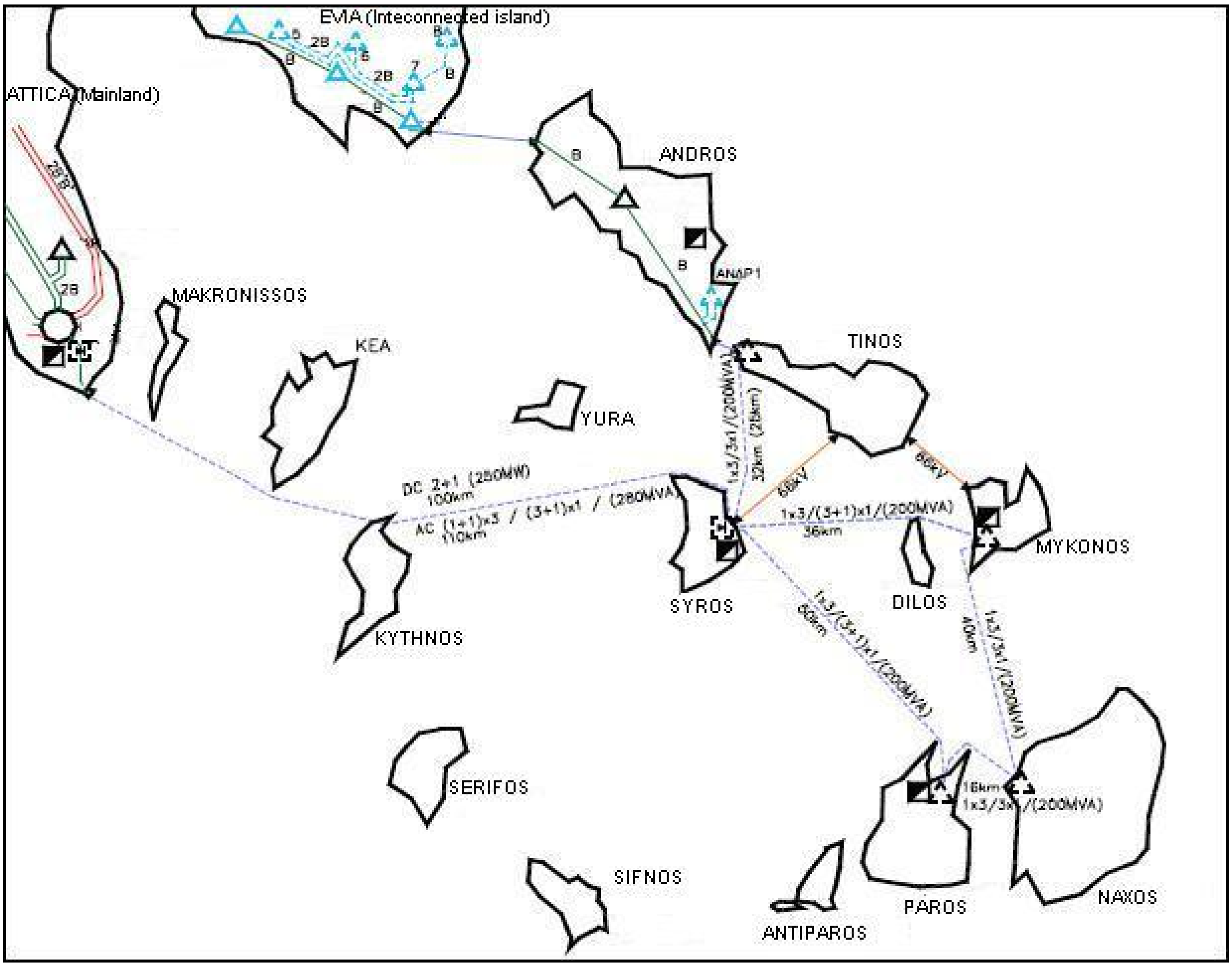

Figure 4. Planned connection of Cycladic islands to the interconnected system

5.1.6 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. Construction was completed in February 2008. However, synchronization of Turkey with the UCTE system will not take place before improvements in the frequency control of the Turkish system take place, in order to comply with UCTE rules. For summer 2008, a temporary connection, using this line, of Greece with an electrical island of the Turkish System is planned. Imports to Greece of up to 250 MW are expected through this connection.

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 depending on the imports of the neighboring countries, 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.

New interconnection with Bulgaria: 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 TSO has requested to investigate the alternative construction of a 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 related cost will be recovered through Transmission Use of System charges.

5.2 Natural Gas [Article 5] and 2004/67/EC [Article 5]

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

5.2.1 Current levels of gas consumption and expected future demand

The demand for Natural Gas in 2007 was 4 bcm, out of which approximately 75% served the Power Generation Sector, as shown in Table 25.

	bcm @ 15°C	Mtoe (HHV)
Power Generation	3.0	2.4
Industry	0.7	0.6
Commercial & Domestic	0.3	0.3
Total	4.0	3.3

Table 25. Sectoral demand in 2007

Demand for the next three years is expected to rise according to the expansion plans of the Gas Distribution Companies (GDC's) and the introduction of three new gas fired powerplants by 2010. Expected future demand for the next three years is presented below in Table 26.

	2008		2009		2010	
	bcm	Mtoe	bcm	Mtoe	bcm	Mtoe
Power Generation	3.50	3.10	3.80	3.50	4.00	3.60
Industry	0.76	0.69	0.79	0.72	0.84	0.77
Commercial Domestic	0.44	0.40	0.54	0.49	0.65	0.60
Total	4.70	4.20	5.10	4.70	5.50	5.00

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

The values of this table are RAE estimates taking into consideration:

- the submitted expansion plans of the 3 GDC's currently operating in Greece,
- the forecasts of the sole supplier of Natural Gas, DEPA S.A.,
- the expected Introduction of new gas fired generation capacity, and
- the electricity demand forecasts for the next 3 years.

Outlook for demand ten years ahead can be very inaccurate, particularly due to uncertainties on global issues such as the EU ETS, the oil prices, as well as local issues such as the participation of Coal and Renewable Energy Sources into the energy mix within this time frame. Given the uncertainties, we doubt the significance of providing one single figure and therefore provide two different assessments, one coming from DEPA S.A., assuming business as usual and increasing sales, and three different figures based on a Long-Term Planning study (LTPS) published last year by the Ministry of Development. The data refer to five year intervals extending to 2020. The presented data refer to the interval between 2015 and 2020 which includes year 2017.

Scenarios		2015		2020	
		bcm	Mtoe	bcm	Mtoe
1	DEPA S.A.	8.5	7.8	9.3	8.5
2	LTPS 1st scenario	6.3	5.8	7.5	6.8
3	LTPS 2nd scenario[1]	6.8	6.2	7.2	6.5
4	LTPS 3rd scenario[2]	6.3	5.7	5.2	4.7

Table 27. Ten year outlook

[1] *Increased RES and CO_2 abatement*
[2] *2nd scenario + Increased Oil prices*

5.2.2 Supply - Demand Situation

Indigenous production during 2007 was zero in Greece. Currently the sole supplier in the NGTS, DEPA, imports gas primarily through long term contracts from 3 different sources, namely Russia, Algeria and Turkey. In 2007 several spot LNG cargoes were unloaded at the LNG Terminal of Revithoussa, supplementing the quantities supplied via long term contracts. Figure 5 shows the Natural Gas sources and their participation to the total imported quantities, as reported by the TSO.

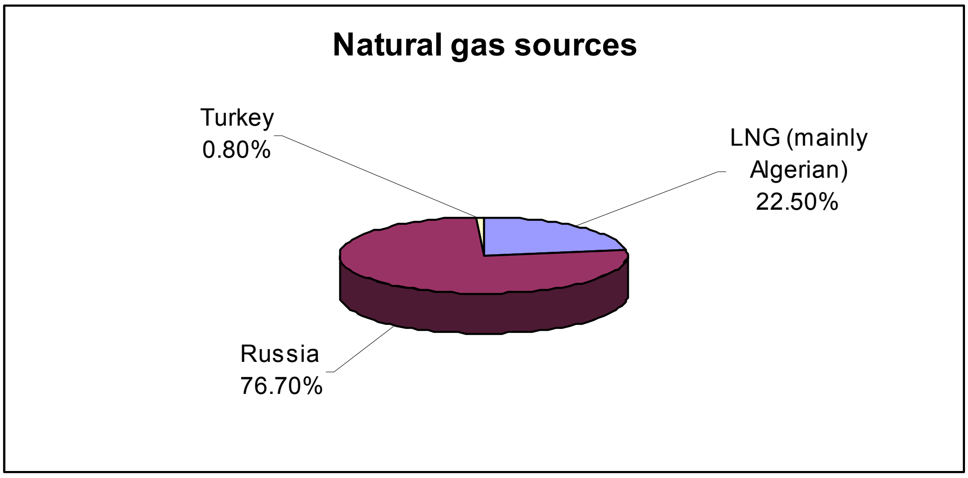

Figure 5. Natural gas sources

The aggregate of the contracted annual quantities according to the three existing supply contracts is shown in Table 28:

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

Table 28. Natural gas contracted annual quantities

Based on information received from the TSO, we estimate that approximately 92% of the demand in 2007 was served by gas procured through DEPA´s aforementioned long-term contracts. The remaining gas, approximately 0.3bcm was apparently provided from LNG cargoes procured on the spot market.

Table 29 presents the anticipated supply gap for the next three years based on the expected demand and the existing long-term supply contracts.

	2008		2009		2010	
	bcm	Mtoe	bcm	Mtoe	bcm	Mtoe
Demand	4.7	4.2	5.1	4.7	5.5	5.0
Supply Contracts	4.1	3.7	4.4	4.0	4.4	4.0
Supply Gap	0.6	0.5	0.7	0.6	1.1	1

Table 29. Expected Supply-Demand balance

According to DEPA, the supply gap is expected to be filled with gas from:

a. LNG from the spot market

b. New long-term supply contracts to be concluded by DEPA

c. New suppliers entering the Greek Market

As yet, RAE has not received concrete information regarding the last two possibilities. However, the TPA regime designed for the LNG terminal of Revithoussa aims to facilitate the entry of new gas supplies to the Greek Market.

Figure 6 below shows the expected demand - supply balance projected to 2018 according to the scenarios presented in Table 27. The high-demand curve corresponds to DEPA’s demand forecast, while the low-demand curve corresponds to scenario No 3 of the above table.

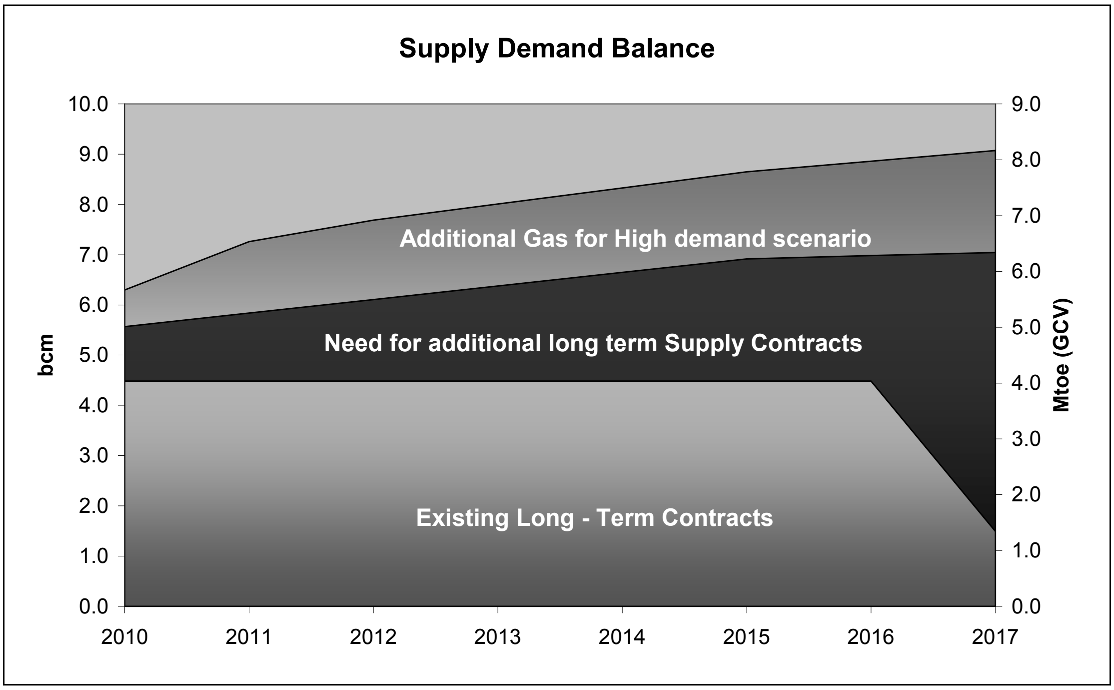

Figure 6. Natural gas supply-demand balance 10-year forecast

5.2.3 Quality and level of maintenance of the networks

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

5.2.4 Emergency measures

Load shedding is the primary measure foreseen in the event of an emergency. According to the provisions of Law 3428/2006 the TSO enters into contracts with customers who choose to be interruptible, and by default with all Dual Fueled Power plant Operators.

As the implementation of the scheme requires the clarification of detailed procedures provisioned in secondary legislation, namely the Operating Code, which is still in the drafting stage, the contracts have yet to be finalized and signed at least between the TSO and the powerplant Operators. However, progress worth mentioning has been achieved during a three-month outage period of the Revithoussa LNG Terminal in 2007, during which the provisions of the Law were enacted with a Ministerial Decision prepared by the Regulatory Authority for Energy. Many of the provisions enacted during that period are considered by RAE valid to be agreed upon contractually.

Furthermore, it is foreseen that load shedding is conducted according to a priority list. On top of the list which includes all customers are Power Installations with dual fuel capability and other interruptible customers that have entered into supply interruption contracts with the TSO. Last on this list are domestic customers. This, being a demand measure is primarily aimed at satisfying peak demand as well as an eventual short term supplier shortfall.

Longer term supply shortfalls however may not be addressed by the above measures and an evaluation of different approaches to enhance security of supply of gas will be conducted by the end of 2008 on the basis of a methodology proposed by RAE. The various approaches that will be evaluated are:

- supplementary LNG storage space at Revithoussa and elsewhere
- underground storage facility
- extension of the Dual Fuel obligation to all NG fired powerplants
- operational Balancing Agreements with adjacent TSOs

5.2.5 Import capacity

The Hellenic Gas Transport System has 3 Entry Points, two at the North and North-eastern borders - Sidirokastro and Kipoi - connecting with the Bulgarian and Turkish gas networks respectively, and one at the Southern part where gas from the LNG terminal is imported to the System. Table 30 lists the entry capacities after the upgrades scheduled for completion in 2008. Annual quantities are derived from maximum hourly flow, considering a load factor of 90%.

Entry points	Theoretical [1]		Actual [2]	
	bcm	**Mtoe**	**bcm**	**Mtoe**
Kipoi	7.1	6.5	N/A	N/A
Sidirokastro	5.5	5.0	3.3	3.0
AG. Triada (LNG Terminal of Revithoussa)	4.8	4.4	4.8	4.4
Total	17.4	15.8	>8.1	>7.4

Table 30. Natural gas entry point capacities

The capacities in columns [1] refer to the max technical capacity at the border, according to the TSO, and do not take into consideration neither the upstream network capacity, nor the downstream constraints. In contrast, data in columns [2] state the known capacity that the upstream network can provide. The data regarding the Turkish network have not yet been provided to the Greek TSO by its Turkish counterpart.

However, due to downstream bottlenecks, not all of the quoted Northern border entry capacities of Table 30 could be delivered at any system exit point. The actual flow that could be injected from any northern entry point depends on the geographic distribution of the demand, the limit being quoted by the TSO at around 10 mcm/day, (equivalent to approximately 3.3 bcm/year given a 90% load factor) assuming a 40/60% North to South demand distribution. When demand is higher than the above figure or the demand distribution increases further in favor of southernmost exit points, the LNG terminal must balance the remaining gas, in order to maintain system pressure within operational limits.

A compressor station scheduled for installation at N. Mesimvria by the end of 2010 will remove the bottleneck along the main pipeline, thereby allowing the transportation of the quoted entry capacities in Table 30 to southern system exit points.

The following Table 31 lists the TSO's investment plans which are planned to add import capacity to the NGTS.

Project	Realization by
Sidirokastro metering station	2008
Ag. Triada metering station	2008
Compressor station	2010
3rd LNG Tank at Revithoussa	TBD

Table 31. Natural gas TSO investment plans

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

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

5.2.6 Security of supply standards

Law 3428/2006 does not make explicit reference to Security of Supply Standards. However, the whole matrix of provisions seeks to provide uninterruptible supply of Natural Gas to all uninterruptible customers during a supply interruption event which may extend to a 5 day loss of all gas supplies from either of the three entry points of the NGTS. The provisions include the following:

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

Supply to Domestic and other small customers is safeguarded in the event of a more extensive supply shortfall, by shedding further loads according to the interruption priority list which will be part of the forthcoming Operating Code.

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

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

5.2.7 Storage capacity

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

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

5.2.8 Extent of long-term gas supply contracts concluded by companies established in Greece

As already mentioned in Section 5.2.2, DEPA has concluded three long-term contracts for the supply of Natural gas from Russia, Algeria (LNG) and Turkey. As the information submitted by DEPA has been classified as sensitive, the graph below lists the contractually available gas in the time frame 2014-2022.

Figure 7. Contractually available Natural Gas through 2022

5.2.9 The degree of liquidity of the gas market

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

5.2.10 Incentives for new investments

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

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

The provisions of the Greek gas legislation are such that allow for the provision of specific incentives for the development of infrastructure that might be proven necessary for the development of the natural gas market. For the time being, there has been no need for the provision of such incentives.

DESFA is currently implementing the investments already included in its initial Development Plan and incorporated into the existing network tariffs. These include, besides the already operational new interconnection with Turkey and the increase of the sent out capacity of the LNG Terminal at Revithoussa, the construction of a compressor station and high pressure branches to new consumers (mainly power plants)

As mentioned in section 4, Greece currently has interconnections with Turkey and Bulgaria from which gas is imported to Greece. In both entry points gas is delivered to the importer (DEPA) directly on the border, by Gazprom Export (Bulgaria) and Botas (Turkey) respectively. There is no regulated third party access regime for Greek entities in the upstream transmission systems of both neighbouring countries, since Turkey has no obligation to implement Directive 2003/55/EC and Bulgaria is not implementing it for the transit pipelines through the country. It should be noted that the entry points of the Greek network are simultaneously exit points for commercial reverse flow, thus providing third party access to the Greek network (e.g .the LNG Terminal) to entities from the neighbouring countries.

New interconnections to neighbouring countries are also in the phase of planning or implementation:

- The Interconnection Greece Italy (IGI), meant to transport gas from the Caspian region through Turkey and Greece to Italy, has shown interesting development in 2007. The project comprises of an onshore part, from the Greek-Turkish border to the western coast of Greece in the prefecture of Thesprotia, and an off shore part (Poseidon pipeline) linking Thesprotia to Otranto in Italy. The onshore part of the project will be built as part of the Greek National Transmission Network under a long-term transportation contract and the regulated third party access regime applicable to it. The sponsors of the project (Edison from Italy and DEPA from Greece) have applied for an exemption for the offshore part of the project, according to the provisions of Article 22 of the Directive 2003/55/EC. The application has been assessed and finally the exemption was granted to the Poseidon pipeline and approved by the European Commission, under specific conditions. Under this scheme, the offshore part of the IGI project has an exemption for the physical flow from Greece to Italy up to a maximum of 8 bcm per year for a maximum period of 25 years. An obligation was imposed to the sponsors to perform, within one year from the approval of the exemption, an open season for an additional 0.8 bcm of capacity, as a minimum, to be offered to third parties, under terms and conditions which will be approved by the Regulatory Authorities of Italy and Greece, while there are additional obligations imposed on the sponsors, with the view to enhance competition and prevent capacity hoarding. Finally, the commercial (virtual) reverse flow from Italy to Greece for the total final capacity of the off shore pipeline, will be available under a fully-regulated TPA regime, under terms and conditions to be approved by the two Regulatory Authorities. The pipeline has to be put in operation in 2012[13].

- An application of a Greek-Russian joint venture has been filed in August 2007, for the construction of an Independent natural gas pipeline linking the Greek and Albanian networks. This application will be assessed as soon as the Licensing Code, anticipated in autumn 2008, is put into entry[14].

- EGL, a Swiss company, have expressed their interest for the construction of a transit pipeline through the Greek territory, with the view to transport gas from the Caspian region to Italy, through Turkey, Greece and Albania. Evolutions to this respect are anticipated[15].

- Finally, discussions have started between the governments of Russia and Greece, for the conclusion of an Interstate Agreement for the development, in the Greek territory, of the part of the transit pipeline which will bring gas from the Russian coast in the Black Sea to the European Union, known as the South Stream[16].

[13] The open-season procedure has been announced in June 2008 and is currently in progress. A detailed report on this will be included in the Report for 2008.

[14] RAE has put its proposal for the Licensing Code in public consultation until the end of September 2008 (http://www.rae.gr/K2/Consult_GasAuthReg.html). Following the conclusion of the public consultation, RAE will issue its opinion to the Minister of Development for the approval of the Code.

[15] In June 2008, an application for this project has been filed to RAE and the Ministry of Development, by Trans Adriatic Pipeline (TAP) AG., a Swiss-Nordic joint venture. The application is being assessed. However, the approval of the Licensing Code is required for the conclusion of the assessment. Details on the issue will be provided in the Report for 2008.

[16] This Interstate Agreement was finally concluded in April 2008.

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 may 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 and/or 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, within three months of the decision on 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 should include in a transparent way the economic rent owed to the PSO provider, as well as the charges allocated to the end users concerning the PSO expenses.

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 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 the PSO should receive.

More specifically, 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 the 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. RAE recently undertook a study on the the appropriate treatment of vulnerable customers and the associated PSO cost. The results of the study will be evaluated in 2008.

6.1.2 Supplier of Last Resort

PPC is obliged to supply eligible customers who are not 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.

For the time being, PPC SA is obliged to supply electricity to all consumers on the non-interconnected islands.

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 intends to apply 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 national daily newspapers and in one local newspaper. Additionally, the licensee should publish any modifications on the terms and conditions (tariffs, method of 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 may not 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 is referred, from either party, to arbitration by RAE. Suppliers are obliged to provide customers with all information needed to complete the switching process (e.g., 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. Moreover, PPC SA is expected to unbundle 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 may withdraw from the contract no later than 30 days and not earlier than 10 days from each cycling period (i.e., 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/she should pay the rest of the fixed fees. However, these 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 an 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; 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 the eligibility or not of the customer.

6.1.6 Primary energy-source labelling

No obligation for primary energy-source labelling exists so far. Nevertheless, recent Law 3468/2006 provides for a procedure that RES 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 RAE.

6.2 Natural 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 DESFA 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) may be imposed to DESFA by means of a Ministerial Decision. DESFA'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 may be imposed to all authorization holders by means of a Ministerial Decision issued after RAE's opinion. Additional obligations may 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 9 Mm^3/year) are obliged to continue the supply of gas to all such consumers, i.e. irrespectively of whather they are their customers, following the instructions of DESFA. 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 the end of 2008.

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/her premises and to the meter, due payment of bills, connection fees etc.

The duration of the supply contract is one year and is automatically renewed unless the customer notifies the company otherwise. The customer may 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.

ANNEX I – Wholesale electricity market SMP graphs

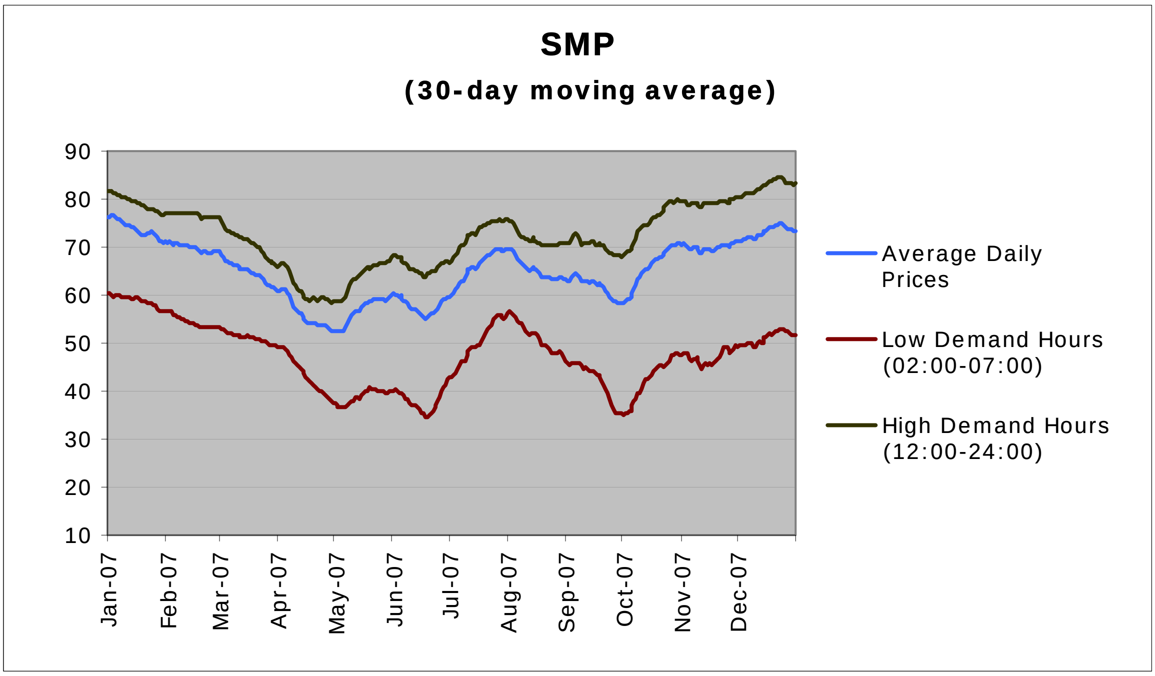

Figure 8. SMP – wholesale electricity market (30-day moving average)

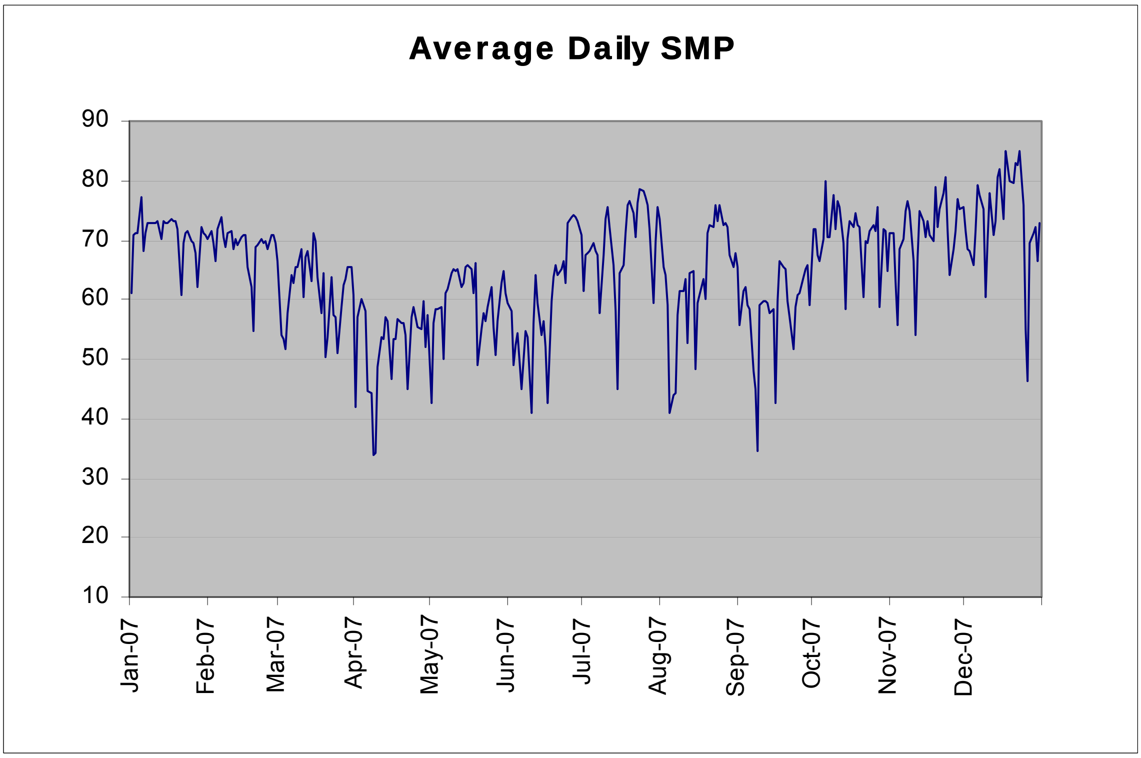

Figure 9. Average Daily SMP – wholesale electricity market

ANNEX II – 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 cost,
- E1 the annual rent 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 rent 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 user connection assets.

- A is the annual depreciation of transmission assets, as are budgeted using the account 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 €/MW. The charge to generation units for using the System does not change during 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 rent 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, before October 31st of 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.

ANNEX III – 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 the 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 Regulator. 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 Pool 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 service 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. Thus, 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 Imbalanced 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 may 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.

ANNEX IV – List of licensed suppliers

1. PPC S.A.
2. ATEL HELLAS S.A.
3. ENEL TRADE S.p.A
4. CINERGY GLOBAL TRADING LTD
5. EDF TRADING LIMITED
6. E.ON SALES & TRADING GMBH
7. RWE TRADING GMBH
8. ENTRADE GMBH
9. VERBUND AUSTRIAN POWER TRADING AG
10. EDISON TRADING S.P.A
11. IRON THERMOILEKTRIKI SA
12. NECO S.A.
13. EFT HELLAS S.A
14. HELLENIC PETROLEUM S.A.
15. EGL HELLAS S.A.
16. INTERNATIONAL ATHENS AIRPORT SA
17. MYTILINEOS ELECTRICITY GENERATION AND SUPPLY SA
18. TERNA ENERGY SA
19. EUROPEAN ENERGY TRADE
20. VERBUND AUSTRIAN POWER TRADING – ENERGA HELLAS S.A.
21. TCB SA
22. ITA ENERGY TRADE LTD.
23. ELECTRICITY TRADING COMPANY HELLAS SA
24. EHOL HELLAS SA
25. ENER SA
26. VIVID POWER EAD
27. ILEKTRIKI THRAKIS SA