National Report 2017

Regulation and performance
of the electricity market and the natural gas market in Greece, in 2016.

Regulatory Authority for Energy (RAE)

Athens, October 2017.

REGULATORY AUTHORITY FOR ENERGY

132, Piraeus str., 118 54 Athens, Greece

Tel.: +302103727400, Fax: +302103255460

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

The Board of The Regulatory Authority for Energy (RAE):

President

Nickolaos G. Boulaxis

(since 23-6-2015)

A’ Vice President

Sotirios Manolkidis

(since 23-6-2015)

B’ Vice President

Michaella Latta

(since 18-2-2016)

Member

Nektaria Karakatsani

(since 22-6-2015)

Member

Ioannis Anagnostopoulos

(since 19-2-2016)

Member

Apostolos Gotsias

(since 19-2-2016)

Member

Theodoros Zervos

(since 19-2-2016)

The Board of the Regulatory Authority of Energy is firmly committed to fulfilling its mandate from the Hellenic Parliament (Law 4001/2011) of participating in collaboration with the Ministry of Energy and Climate in the medium and long term energy market design in Greece, of promoting the security of energy supply to Greece, of approving and licensing new business activities in the energy sector in Greece, of approving the development of the energy infrastructure in the interconnected system and in the non- interconnected system in Greece, of setting (regulating) transmission and distribution tariffs for the use of the domestic energy networks, of monitoring and analyzing the energy markets in Greece, of protecting the consumers of energy , of promoting cross border energy trade and international cooperation in the energy sector. The Board seeks to explain its energy regulatory role and its activities to the public as clearly as possible. Such clarity facilitates well – informed decision making by households and businesses, reduces economic uncertainty, increases the effectiveness of the regulation and enhances transparency and accountability, which are essential in a democratic society.

The Board of the Regulatory Authority for Energy (RAE) is pleased to submit its National Report 2017 to the Council of European Energy Regulators and to the European Commission.

1. Foreword

A Summary. Current reforms in the energy regulation, in Greece.

Dear Readers,

The purpose of the Current National Report is to provide you with a concise overview of the most important changes in the energy regulation in Greece, in 2016. Regulatory changes always affect the performance of the energy sector. Thus, the current Report illustrates the performance of the energy sector in Greece. The Greek electricity generation mix in the interconnected system (mainland) has a diversified structure considering that lignite units generated 14.898 GWh, natural gas units generated 12.680 GWh, RES units generated 10.191GWh, Hydro (large) units generated 4.843 GWh and import flows supplied almost 10.966 GWh, in 2016. It is noticeable that RES including Hydro for first time, were the largest generators of the Greek power generation mix in 2016, generated 15.043GWh (see ch.3).

The energy system transformation that Greece is undertaking entails significant structural changes for the energy sector through greater energy efficiency, larger contributions from renewable energies while ensuring the continuous low-carbon nature and security of its electricity supply. This transformation has implications for maintaining energy security in the short to medium term given the ageing of the lignite generation units. Therefore, it was necessary for Greece to introduce demand response measures and retain a capacity market mechanism in 2016 with a view to ensuring power system adequacy at peak demand and integrating larger shares of intermittent sources of electricity generation. These measures were proved to be essential for the management of the supply crisis due to the extreme weather conditions in December 2016 (see ch.4).

In attempting to encompass the range of new regulatory developments in the year 2016, this Foreword Summary has the aim to summarize the main regulatory reforms that took place with the positive contribution of RAE, in the electricity and natural gas sectors. We present the main regulatory reforms as follows: a) reforms in the electricity regulation, b) reforms in RES regulation and c) reforms in the natural gas regulation.

Electricity Regulation:

<u>The reorganization of the Greek wholesale market was endorsed by the Greek parliament</u>, in 2016. Law 4425/2016 specifies the steps for the re-organization of the Greek wholesale electricity market towards the implementation of the EU internal market model (henceforth “the Target Model”), meaning among others; a) the establishment of an intra-day electricity market, b) the establishment of a forward electricity market c) the establishment of a balancing market, d) the establishment of regional markets e) the coordination of the operation of the national networks (interoperability, security of supply, common trade rules and procedures), and f) a closer cooperation of the transmission system operators and the national regulators for cross border energy exchanges and for systems’ efficient interoperability.

The first Auctions of wholesale electricity products by the Public Power Corporation (PPC S.A.), the incumbent, to reduce its market share in the wholesale and retail markets took place, in October 2016. Auctions' "philosophy and organization" are based on the French electricity market model "Nouvelle Organization du Marché de l' Electricité" (NOME Law), which was adopted in the French electricity market, in 2010. More specific, first tendering of PPC's offering of its lignite electricity generation to the Independent private producers and suppliers has already taken place. – that is one of the actions/measures taken by the government for the limitation of PPC's share in the wholesale and the retail markets to less than 50% (up to the year 2020). RAE issued the code of auctions and exchanges of future electricity products, in September 2016 (RAE's decision ref. no 329/23.09.2016).

A new Generation Capacity Reserves Mechanism has been set for the period 2016 -2017. The new mechanism has been characterized as a transitional measure for the period 2016 – 2017 towards a Permanent Generation Capacity Reserves Mechanism which must be adopted by RAE in cooperation with the Ministry of Energy by the end of 2018. After the termination of the use of the Capacity Remuneration mechanism in 2015 in attempt to prevent the uninterruptable operation of the electricity system, a transitory remuneration mechanism toward to a permanent one was adopted for the period 2016 -2017. A new permanent capacity remuneration mechanism is prepared taking into consideration: a) the reflections of DG Competition and of DG Energy, b) market operation and efficiency, and c) the special characteristics of the Greek electricity network.

Smaller regulatory changes in the wholesale electricity market took place in 2016 such as; a) the increase of the price cap at the Day Ahead market, b) the introduction of a new methodology for the calculation of the entry price for the hydro - electric power stations based on the opportunity cost, i.e. the weighted average cost of thermal generation, c) the introduction of interruptible Load contracts via auctions for large industrial consumers, d) a new charge on load representatives to remunerate RES production (aggregators) for the benefit they bring to the market by reducing the System Marginal Price.

The Public Power Corporation (PPC) concluded the negotiations on HV tariffs (high voltage tariffs) with all its HV customers by signing the respective contracts, and the adopted tariffs shall be cost-based and consider consumption characteristics. Following extensive negotiations, the Board of Directors of PPC has approved on 28 September 2016 the terms of agreement with Aluminum of Greece (AoG), PPC's largest customer. These terms have been formally approved by the General Assembly on 5 October 2016 and the contract signed directly thereafter. With this signature, except for four cases concerning a company under liquidation and three companies which have ongoing legal disputes with PPC, all PPC's High Voltage (industrial) customers have signed a cost-based and consumption-profile based contract.

RAE approved the Ten Years Network Development program of the Greek TSO, ADMIE S.A. Additionally, RAE Approved the 7 years Electricity Supply adequacy program of the Greek TSO. Furthermore, RAE participates in the discussion for the update of the EU list of projects of common (cross border) interest (PCI) which is published every two years (next publication in 2017).

TSO's full unbundling (separation of business activities) process from the incumbent, PPC S.A., started in 2016 and completed in the beginning of 2017; Government's plan is to privatize part of the TSO ownership and terminate fully PPC ownership of ADMIE but, holding a share of public ownership. The General Assembly of PPC authorized the sale of at least 24 percent of ADMIE S.A. to a strategic investor, in Summer 2016. The General Assembly took place on 11th July 2016 and voted the sale of 24%. The tender was launched by publication on PPC's website directly thereafter. Finally, the new strategic investor, approved by PPC's shareholders, is the State Grid International Development S.A. (China). The transaction was approved by the government, in January 2017.

RAE is taking all the steps for the successful Implementation of the EU regulation (network code) on transmission capacity allocation and congestion management (CACM), meaning that it is preparing and making all the necessary amendments on the domestic network codes. Under the CACM regulation implementation process, ACER took the final decision on the formation of (10) capacity calculation regions. Greece participates in two regions, Region 7 (Italian-Greek border) and region 10 (Greece-Bulgaria-Romania border). In addition, RAE in cooperation with the Ministry and the TSO are preparing the full implementation of the recently adopted European network codes (balancing and forward capacity).

For first time, Demand Side Response measures are applied in the Wholesale and Retail markets: Preparation of the new distribution code to include demand response measures, and simplicity on consumers' switching electricity supplier procedures took place in 2016. Till to the year 2015, consumers could participate in the markets (demand response) only through the option to consume day or night and be charged with the respective daily tariff rate or the night (lower) tariff rate, and from their side TSO/DSO and generators could manage peak demand only through providing multi-band tariff rates (day/night rates). The Greek Law 4342/2015 (Official Government Gazette FEK A' 143/09.11.2015 has integrated EU Energy Efficiency Directive (henceforth EED) 2012/27 into the Greek legal system, which requires among others: a) member states to adopt demand side response measures, b) legal and physical entities to provide balancing and/or auxiliary services and c) the regulator to expand its monitoring role for the successful implementation of the energy efficiency directive in the market.

Further actions for the effective implementation of the EU regulation on the (electricity and natural gas) wholesale markets' integrity and transparency (REMIT) have been taken by the regulator. RAE completed successfully the registration of all market participants in electricity and natural gas markets in the centralized European Register for Wholesale Energy Market participants' platform (CEREMP), in September 2015, and all the requirements for the reporting of market participants' standard contracts transactions, on 7th October 2015. The reporting of market participants' transactions take place through the Registered Reporting Mechanisms which have been certified by RAE. RAE has already recognized as Registered Reporting Mechanisms: The Market operator of the electricity market (LAGIE S.A.), the operator of the electricity transmission system (ADMIE S.A.) and the Public Corporation of Natural gas (DEPA S.A.).

Furthermore, RAE followed all the required steps for the successful completion of the process for the reporting by the market participants, any other transactions that do not take place in organized markets (over the counter transactions), on 7th April 2016. Currently, RAE develops its cooperation with the Hellenic Competition Commission (especially on the fields of: a) common investigation procedure, b) an enforcement law, c) penalties imposed on the markets participants that violate wholesale market rules), and with the Hellenic Capital Market Commission (exchange of information related to the energy companies' activities and their energy products which might be offered in the forward markets in the following years).

In addition, RAE participates in ACER's discussions on the new European Electricity Market Design model proposed by the European Commission in November 2016 (i.e. new regulation on electricity market regulation, a new RES directive, a new ACER governance regulation etc.).

B. RES Regulation.

The Ministry in cooperation with RAE amended the current legislation on ETMEAR (RES levy) and the structure of the RES financial support account to ensure that the debt in the RES' account is eliminated over a 12-months forward looking horizon (not later than June 2017); the account will be kept annually in balance onwards (Law 4414/2016). It also foresees elimination of the debt in the RES account by December 2017, which is longer than the originally envisaged timeframe, but includes a corrective mechanism to prevent further or persisting imbalances of the RES account during this timeframe. Moreover, regular provision of data on the RES account has been agreed with the TSO (ADMIE S.A), DSO (DEDDIE S.A.) and the Market Operator (LAGIE S.A.).

The amendment on renewable energy incentives has also been approved by the referred Law on 4th August 2016 (Law 4414/2016). Further (explicit) amendments on RES incentives have been legislated on 6 October 2016. The main change in the new RES support financial scheme is the abolition of the Feed in Tariff financial support mechanism for new RES projects, larger than 5MW and the adoption of the new mechanism of Feed in Premium. The new financial support scheme was approved by the European Commission (DG Comp), in November 2016.

C. Natural Gas Regulation.

RAE adopted the gas distribution and transmission new tariffs. On distribution, the methodology was published in the Official Gazette on 26th September 2016 (FEK B 3067), and adoption of the actual tariffs has taken place, on 7th October 2016. Transmission tariffs had their methodology changed retroactively through legislation (Law 4009/2016). The new tariff adopted, on 8th October 2016.

For work on unbundling, meaning the separation of business activities of generation from transmission, distribution and supply; the legislation was adopted initially on 4th August 2016 (Law 4414/2016). Legislation will be amended further facilitating the unbundling process of: a) the natural gas TSO (DESFA S.A.) by DEPA and b) the regional natural gas retail corporations (EPAs) separation of the ownership and operation of distribution systems from retail operation activity. Separation of EPAs from DEPA. RAE is working for the completion of this process.

As concerns DESFA SA: the TSO's privatization process, the final Discussions between the government, the Regulator, Socar S.A. (Azerbaijan) and Snam S.A (Italy) took place for the sale of 66% of shares of the Greek Transmission System Operator and the setting of the transmission tariff rates. But, SOCAR S.A. announced its decision to cancel its investment in the Greek TSO, in December 2016.

Regarding the Public Corporation DEPA S. A's release (sale) program of its own natural gas: several necessary amendments were made on gas release (sale) program of DEPA S.A. The authorities (the Ministry and RAE) completed the review of new the gas release (sale) program of Public Corporation of Natural Gas (DEPA S.A.). The new release program improves the conditions of access for alternative suppliers and substantially increases the quantities available. More specific, a written proposal by DEPA with revised commitments omnibus bill, i.e. improved access conditions and increased quantities up to 20% in 2020, sent to the Hellenic Competition Commission (HCC) and endorsed by HCC in 2016.

Regarding the Retail market, RAE took a decision on the free operation of the retail suppliers on the Greek territory meaning the termination of the geographically defined areas of operation, and of exclusivity supply rights. A transition period was set (2017-2018).

Greece- Bulgaria natural gas interoperability agreement: The Greek TSO and the Bulgarian TSO with the approval of the Greek regulator and the Bulgarian regulator signed an interoperability agreement for the Bulgarian – Greek interconnector. The agreement strengthens the cooperation of the TSOs and the coordination of the two national transmission systems.

Infrastructure development: RAE approved the TEN years' development program of the Greek TSO (DESFA) and is working for the update of the European list of the projects of Common Interest (PCI), in 2017. As for the Trans Adriatic pipeline (TAP), the construction of the Greek part started in 2016. In addition, a new Greece – Bulgaria Interconnector (IGB) is planned. A Market test was organized by the ICGB AD (i.e. the company responsible for the construction of IGB) to see the response of the potential market participants and it was successful. After the completion of the second stage of the market test, the Bulgarian and the Greek Regulators will evaluate company's application for exception and they will decide if they will offer an exception right to the ICGB AD. Discussions between the two: the Bulgarian and the Greek regulator continue.

A New LNG terminal. A New offshore LNG Floating and Storage regasification unit (FSRU) near Alexandroupolis. The project is part of the list of the European projects of common Interest (PCI). Bulgaria (Bulgargas) has announced its willingness to participate in the project. The annual capacity of the new LNG project will not be more than 5bcm. The project will give the opportunity to Bulgaria and Romania to have access to new sources of natural gas supply from Qatar, Iran, Algeria, Israel, Egypt, Cyprus and USA. Gas supply diversification will increase security of supply, increase competition and will decrease prices of natural gas and electricity in the region. In addition, it will limit the need for nuclear power use- increasing environmental safety and will strengthen the idea for a North - South natural gas corridor (from Poland to Greece, the Aegean Sea). But for the success of the project other smaller projects should be completed soon such as the IGB, the reverse flow to the existed interconnection pipeline between Greece and Bulgaria. Considering the tensions periodically between Turkey and Russia, Russia and the European Union, Turkey and the European Union, tensions between Turkey and Iran, an LNG terminal in Northern Greece will increase the security of natural gas supply for the region of Central and Eastern Europe.

2. Main developments in the electricity and gas markets

2.1 Electricity

RAE is proceeding with a power market restructuring plan which is the implementation of "the Target Model"[1] in the Greek wholesale electricity market, based on the European Regulations, Directives and Guidelines.

For this purpose, RAE in cooperation with the TSO (ADMIE S.A) and the wholesale market operator (LAGIE S.A) made their proposals and recommendations to the Ministry of Energy and Environment for the necessary legislative reforms and amendments in line to the European electricity target model. We recall that the electricity target model aims to the establishment of the following 4 (sub)markets: the establishment of a day ahead market, an intra-day market, a balancing services market and a forward market. Thus, a new Law was issued (Law 4425/2016) for the transposition of the European electricity target model to the legislative framework of the domestic wholesale market, in September 2016. For the implementation of Law 4425/2016, RAE after its consultation with ADMIE S.A., and LAGIE S.A. and an open to the public consultation, issued a Decision (Ref no. 67/2017) about the Regulator's Guidelines to the TSO and to the Market Operator for the development of the necessary network codes for the operation of these 4 markets. Per the restricted timeframe of the RAE's Guidelines/Decision, the completion of the network codes is expected to take place, in 2018. RAE is following and monitoring the procedure. The responsible entity for the development and completion of the network codes for: a) the intra-day market, b) the day ahead market and c) the forward market, is the domestic market operator LAGIE S.A. The responsible entity for the development and completion of the network code for the electricity flows' balancing is the domestic TSO, ADMIE S.A.

<u>Regarding the implementation of the European Regulation 2015/1222</u>, Guidelines for the Capacity allocation and congestion management, RAE issued decisions about the European common methodologies and common rules for the joint operation of the cross - border network interconnections. Per the Regulation 2015/1222, these common methodologies and rules are

---

[1] The Target Model is the common vision for a European electricity market and for a European natural gas market which regulators, the European Commission and the Transmission System Operators are seeking to put in place. The Third Package of the European Regulations and directives for the energy markets (2010) went further than previous initiatives to restructure the European energy markets, in the direction the national markets to become more integrated among each other, more competitive and more efficient. Thus, the third energy package set out a process to develop the rules (network codes, additional regulations) which allow the completion of the internal electricity and natural gas markets (henceforth the Target Model).

decided jointly by the national regulators of the cross - border interconnectors in coordination with the European Agency for the Cooperation of the Energy Regulators (ACER).

Although no changes in the rules of the wholesale market (i.e. a day ahead mandatory pool) were introduced during 2016, the supply support mechanisms (Cost Recovery Mechanism and the Transitional Capacity Assurance Mechanism) which exerted a substantial impact on market outcomes, had already revised in crucial aspects in 2015. Both mechanisms take the form of a Transitional Flexible Remuneration Capacity Mechanism (FRM), in 2016.The new mechanism will be operational only for the period 2016-2017. As a result, the European Commission approved, finally, the new mechanism (FRM) for one more year as a transitional measure to the target model C (2016)1791 final/31.03.2016.

With the law 4389/2016, the approved by the European Commission Transitional Flexible Remuneration Capacity Mechanism (FRM) was transposed into the Greek legislation. According to the Law 4389/2016 and the commitments of the national authorities to the European Commission for the transitional character of the FRM in the domestic wholesale market, RAE in cooperation with ADMIE SA had to proceed to:

a) amendments to the network code
b) amendments to the market clearing procedures
c) establish a list of eligible generation units which may participate in the capacity reserves mechanism
d) establish a methodology of imposed sanctions.

In this context, since the adoption of this (transitional) mechanism is linked to the commitments by Greece to reform various aspects of the wholesale electricity market, RAE took the initiative to set up an expert group, consisting of members of the Regulator, the System Operator (ADMIE S.A) and the Market Operator (LAGIE S.A.), which refined the relevant commitments and constructed a roadmap for their implementation. These commitments include the following measures:

- Increase the maximum bid price limit of the day ahead market scheduling (DAS) from 150€/MWh to 300€/MWh.
- Require Statements of capacity generation availability of hydroelectric power plants.
- Increase the limit of the secondary backup offers.
- Introduce a Pricing Methodology for the hydroelectric generation (unit) cost.
- Compensate (and) the tertiary reserves
- Re-evaluate the framework of charges for electricity exports to charges of the Uplift Accounts (settlement accounts from market clearing – i.e. imbalance settlements in the wholesale market of the day of the system operation).

Furthermore, RAE fulfilled its commitment to reassess the framework of charges for electricity exporting activity with its Decision 471/2015 according to which, from 01/01/2016 exports are exempt from the charges of the Uplift Account UA-2, UA-5 and UA-6, because these charges are not directly related to an inherent and integral part of the production costs themselves for exported electricity nor concern financial costs such activity is causing or likely to cause, by direct causation, the Transmission System Operator.

For the permanent Generation Capacity Reserves' Remuneration Mechanism, whose implementation is the responsibility of Greece in accordance with the provisions of paragraph 4.3 of Section III of Article 3 of Law 4336/2015 (Government Gazette 94 / 09.14.2015), RAE set up a relevant Working Group in 2015. RAE in cooperation with the TSO (ADMIE S.A) analyzed the options for the design of the new mechanism. There was an agreement on the basic principles of the mechanism and an agreed explicit document of the mechanism was released for public consultation and pre-notification to the European Commission (DG D / Directorate of Competition).

Regarding the Auctions of wholesale electricity products by the Public Power Electricity Corporation (PPC SA): based on law 4336/2015 which detailed the Greek Government's responsibility to reduce PPC's market share by 25% and fall below 50% by 2020, while system marginal prices will cover the cost of production, RAE submitted to the Ministry of Energy and to the Central Unit for State Aid, a proposal for the creation of a forward market based on NOME type auctions: an auction process with a regulatory-defined starting price that reflects the full cost of efficient lignite production in Greece. The basic concept for the product design, as introduced in RAE's latest document, provides the opportunity for the whole spectrum of consumers to be supplied by other suppliers as an alternative to PPC. The starting point is designed to be the current level of end-prices for all customer categories. The quantity to be auctioned concerns 1200 MW of baseload lignite and hydro generation. The auctions are organized on an annual and quarterly basis for each year, for 4 years (2016-2020). The auctions are transitional and designed so that by 2017 (EU Target Model will be in place), "there will be similar products traded on market basis that will provide the opportunities for suppliers and generators to manage in a long-term basis their positions". In September 2015, a joint working group was formed by a Ministerial Decision (39229/16.09.2015) with the purpose of organizing and managing the implementation of NOME type auctions. Thus, RAE issued the code of auctions and exchanges of forward electricity products in September 2016 (RAE's decision ref. no 329/23.09.2016). The initial price for the auction (the reference price) was decided with a Ministerial Decision in September 2016 and the first auction was organized successfully by PPC S.A, on 25th October 2016.

Smaller regulatory changes in the wholesale electricity market took place in 2016 such as: a) the increase of price cap at the Day Ahead market (it has already been referred above), b) the introduction of a new methodology for the calculation of the entry price floor for the hydro - electric power stations based on the opportunity cost (i.e. the weighted average cost of thermal generation), c) the introduction of interruptible Load contracts via auctions for large industrial consumers (for more explanation see the next paragraph), d) a new charge on load representatives to remunerate RES production (the aggregators) for the benefit they bring to the market by reducing the System Marginal Price.

Regarding Demand side response measures in cases of supply crisis' situation: interruptible load services (ILS) were provided to the market for first time, in 2016. The Greek Law 4342/2015 (Official Government Gazette FEK A 143/09.11.2015 has integrated EU's Energy Efficiency

Directive (henceforth EED) 2012/27 into the domestic legal framework, and requires among others: a) member states to adopt demand side response measures, b) legal and personal entities to provide balancing and/or ancillary services and c) the regulator to expand its monitoring role for the successful implementation of the energy efficiency directive in the market.

In 2016, the Greek TSO (ADMIE), organized 5 auctions of two types of interruptible load services (ILS). ADMIE defined two offered types of interruptible load services, as follows:

Table 1: Interruptible Load Services in 2016.

Types of Interruptible load services (ILS)	**Warning time**	**Maximum time of order**	**Maximum time per year**
1*	2 hours	48 hours	144 hours
2**	5 minutes	1 hour	24 hours

*Minimum time between two successive orders for the type 1 interruptible load services (ILS) is 1 day. Maximum no of orders of type 1 ILS is 3orders/month.
**Minimum time between two successive orders for the type 2 ILS is 5 days. And the maximum no of orders of the type 2 ILS, is 4orders/month.

The first two auctions (one auction for each type of ILS), were organized by the Greek TSO (ADMIE) and took place on 29th February 2016. The two auctions covered the period from March 1st to March 31st ,2016. For every auction, the offered load capacity was 500MW. The second two auctions (one auction for every type of ILS) were organized by the Greek TSO (ADMIE) in March, both auctions covered the period from 1st April to 30.04.2016. for the type 1 ILS auction, the offered load capacity was 650MW and for the type 2 ILS the offered capacity was 850MW. The third two auctions were organized by the TSO on April and took place on 27/4/2016. Both auctions covered the period from May 1st to September 30th. For the type 1 ILS auction, the offered load capacity was 750 MW. For the type 2 ILS auction the offered capacity was 900MW. The fourth two auctions for the year 2016 were organized by the Greek TSO and took place on 27/9/2016. Both auctions covered the period from October 1st 2016 to December 31st 2016. For the type 1 ILS auction, the offered load capacity was 550MW, and for the type 2 ILS auction, the offered load capacity was 650MW. The fifth two type auctions were organized by the TSO, in December. Both auctions covered the period from 1st January 2017 to 31st March 2017. For the type 1ILS the offered load capacity was 750MW and for the second type ILS auction the offered capacity was 900MW. The allowed minimum bid offer of each participant was not less than 3 MW. All auctions were successful, (demand excessed supply).

Regarding the continuous monitoring of the market liquidity level across the electricity supply chain in 2016: the cash flows' liquidity conditions in the domestic energy market remained extremely critical, due to the overall adverse conditions in the Greek economy in general and the continuous severe lack of financing and credit for the energy sector. The core problem remains the unpaid receivables of PPC: as the dominant supplier (retail market share >98%), the rate by which PPC collects its receivables has a major impact on the whole electricity value chain and the relevant cash flows. Despite its efforts to improve its collection procedures, eventually, PPC was not able to improve its rate and at the end of 2016 it estimated unpaid receivables of €2,4 billion.

Regarding the wholesale market performance and the electricity generation's used fuel mix in 2016: the steady level of consumption in 2016 (46,4TWh) compared to the level of consumption in 2015 (-0,3% decrease only), and the increase in imports in the second half of the year, boosted domestic electricity generation particularly from natural gas plants from 8,3TWh in 2015 to 13,6TWH in 2016 (63% increase)[2] . More specifically, the lignite production showed a further substantial fall -23% (-4,6TWh) in 2016 compared to the year 2015. The lignite production was 14,9TWh in 2016, 19,4 TWh, in 2015 and 22,7 TWh in 2014. In 2016, the imported electricity volumes decreased moving from 11,3 TWh in 2015 to 10,9TWh in 2016 (net trading volumes were 8,7TWh in 2016 from 9,68TWh in 2015). Although the growing rate of building new RES capacity has dropped drastically, due to changes in the legal framework during 2013 and 2014 and to the domestic economic depression, the share of RES in total consumption was 24%. That calculated number for the share of RES does not consider the share of large hydroelectric plants in total generation and in total consumption. In the retail market, PPC also remained by far the dominant supplier, as it held almost the entire retail market (97,6% of the total number of customers and about 89% of the total electricity supplied). Although 13 other suppliers were active, the switching rate remained very low (see ch.3).

Regarding the non-interconnected islands (NIIs): in 2014, RAE adopted the Operation Code for Non-Interconnected Islands (NII Code), which largely completed the secondary legislation that regulates the operation and the transactions at the NII electrical systems, setting the grounds for open competitive markets, in both the production and the supply activities on these islands. At the same time, the European Commission, acknowledging unique conditions, granted to Greece derogation from the provisions of Chapters III and VIII of Directive 2009/72/EC for the NIIs: a) for the refurbishing, upgrading and/or expanding of PPC's existing power plants until 1.1.2021, but not for new capacity, b) for a maximum of five years after the adoption of the NII Code, until the necessary infrastructure is in place, for the activity of supply (EU Decision 2014/536). In 2016, the EU Decision was transposed into the Greek Law (4014/2016). The EU Decision and the new Law granted also the right to "alternative electricity suppliers" to participate in NIIs. Thus, the year 2016 is the first year that (9) other suppliers (additionally to PPC) participated in the NIIs' market (island of Crete).

[2] Due to the mandatory physical trading in this market, the traded volume of electricity is equal to the total production (the DAS outcome) plus the net interconnection balance. This value was equal to 51,2TWh in 2016 (51,3TWh in 2015), reflecting a marginal decrease of -0,28% relative to 2015. These numbers (the real consumption) both based on the grid metering (demand at the grid level) plus the PVs connected to the distribution network (i.e. prosumers and small producers at the distribution level) for more, see Table 21 and Figure 5.

2.2 RES

The Ministry of Energy in cooperation with RAE amended the current legislation of RES. A new support scheme for renewable energy resources (RES) and high efficiency combined heat and power (HECHP) installations published on 9th August 2016. The national Legal basis is Law 4414/2016 on a new support scheme for RES and HECHP. The support scheme intends to incentivize electricity production from RES to contribute to the achievement of the target set by Directive 2009/28/EU on the promotion of the use of energy from renewable sources at 20% share of energy from RES sources on the EU overall gross energy consumption in 2020. Directive 2009/28/EU, set this target for Greece, based on GDP/capita, energy consumption and other indicators, at 18% share of RES on Greece's overall consumption in 2020.Based on data from Eurostat 2014, Greece's RES share on total final gross energy consumption was 15,32% in 2014, with electricity from renewable sources (RES-e) representing almost 24% of the total electricity generation. Significant new investment still required to reach the above mention achievement national RES target. It is estimates that, in terms of electricity generation capacity, the current gap which must to be covered by the year 2020, if nothing change, is currently moving between 2.000MW and 2.500MW. In Table 2 we report the total number of RES projects with a license approved by RAE by the end of the year 2016.

Table 2: Projects with a license/permission of generation (non- operational) approved by RAE, end of year 2016.

Technology	No of Licenses	Capacity Power (MW)
Wind	1128	23.717,02
PV	908	4.184,07
Hydro (small)	436	976,23
Geo	1	8
Biomass	87	381,61
Solar	82	442,2
Hybrid	20	345,05
Co-generation (electricity & heat)	66	416,92
Total	2.728	30.471,1

Technology	Table 3: Number of RES applications and number of generation licenses							
	2015				2016			
	Number of Applications for generation license		Decisions/ Permissions approved by RAE		Number of Applications for generation license		Decisions/ Permissions approved by RAE	
	No	Power Capacity (MW)	No	Power Capacity (MW)	No	Power Capacity (MW)	No	Power Capacity (MW)
Wind	20	183,70	25	467,00	79	429,6	15	178,6
P/V	2 *	3,66	13	185,80	0	0	3	16,89
Hydro small	6	8,31	6	5,30	33	79,52	5	7,62
Biomass	18	85,50	3	31,19	10	27	1	1,5
Cogeneration electricity& heat	1	4	2	32,00	1	4,54	0	0
Solar	0	0	0	0	0	0	0	0
Hybrid	1	1,80	0	0	56	294,31	1	0,96
(Tele) heating	1	9,80	0	0	0	0	0	0
Total	49	296,77	49	721,30	179	834,79	25	205,57

The main change in the new RES support financial scheme is the abolition of the Feed in Tariff financial support mechanism for new RES projects, larger than 5MW and the adoption of the new mechanism of Feed in Premium. In addition, the new legislation amended the RES' levy (ETMEAR) and the structure of the RES financial support account to ensure that the debt in the RES account is eliminated over a 12-months forward looking horizon (not later than June 2017); the account will be kept annually in balance onwards. The initial amendment on renewable energy incentives had been approved on 4 August 2016 (Law 4414/2016). An amendment which brings several points in line with the milestone has been legislated on 6 October 2016. It also foresees elimination of the debt in the RES account by December 2017, which is longer than the originally envisaged timeframe, but includes a corrective mechanism to prevent further or persisting imbalances of the RES account during this timeframe. Moreover, regular provision of data on the RES account has been agreed with the transmission system operator (ADMIE S.A), the distribution system operator DSO (DEDDIE S.A), and the market operator (LAGIE S.A). The new financial support scheme for new RES projects was approved by the European Commission, in November 2016.

The main objective of the new RES support mechanism is to achieve an efficient integration of renewables' generation into the electricity market. The fields of energy and environment were included in the EU Guidelines on State Aid, notably, the "Guidelines on State Aid for environmental protection and energy 2014-2020" (EEAG), issued on 9th April 2014, and applicable from 1st July 2014. The EEAG clarify the assessment rules of State Aid cases, regarding compatibility with internal market (Art. 107[2&3] of the EU Treaty). Specifically, the Guidelines spell out the conditions to be met, inter alia by the support schemes to ensure compatibility with the rules on State Aid, with a view to strengthen the internal market, promote more effectiveness in public spending, introduce a greater scrutiny of the incentive effects and limit the aid to the minimum necessary, to avoid the potential negative effects of the aid on competition in the internal market

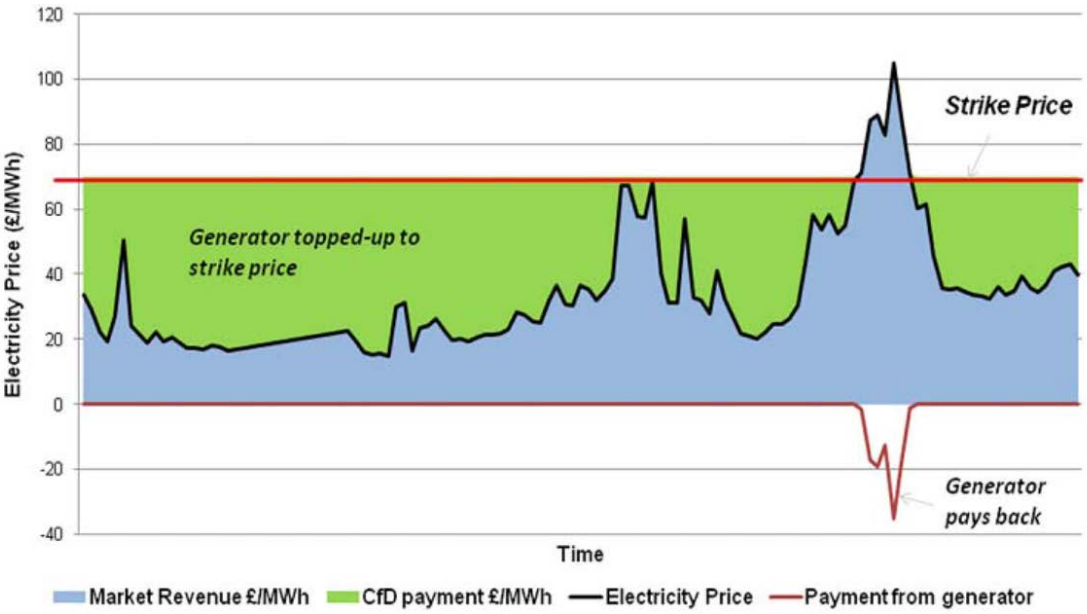
The new scheme is designed to support revenue based on cost reflective, market-based Operating Aid, which will ensure that both phenomena of *over-compensation* and *under-compensation* of power generation from RES and HECHP are minimized. A technology-specific **Sliding Scale Feed in Premium (FiP)** will be added as a premium, to the revenues received by the RES producers, through their participation in the wholesale electricity market, for the relevant Operating Aid to reach an acceptable level of support, measured against **a Reference Tariff (RT)** per renewable energy technology. The RTs will be initially administratively determined for all technologies and from 2017 will be set through competitive bidding for most producers, on a project-by-project basis.

As from 1 January 2016, all RES and the small combined heat and power plants (henceforth HECHP power plants) with generation capacity less or equal to 30MW that commence (commissioning or commercial) operation in the interconnected system, participate in the electricity market, and are included in a support mechanism in the form of *Operating Aid* based on a *Differential Compensation Price* (*Sliding Premium*), for the power they generate and is absorbed by the interconnected system. The *Sliding Premium* is expressed in a monetary value per measurement unit of the generated power that is injected, and which is cleared, billed and its transactions are settled monthly, in accordance with Article 5 of the Law.

The *Sliding Premium* shall be calculated monthly, as the difference between on the one hand, the **RT** applicable for the *"Contracts of Difference"* (Feed in Premium Contracts FiPC), and on the other hand, the **Special Market Price for Renewables (SMPRES)** for the specific RES, or HECHP technology: **FiP = RT – SMPRES**. The FiPCs are signed between the producer and the Hellenic Electricity Market Operator (known by its Greek initials as "LAGIE"), for the power generated from RES and HECHP plants under Article 10 of the Law, and which is defined per RES and HECHP power plant technology and category, or per RES or HECHP power plant, in case this results from the conduct of competitive processes, in Euro per megawatt hour (€/MWh). The SMPRES will be calculated differently for *intermittent* (i.e. wind power, solar PV and small hydro power plants) and *non-intermittent* (i.e. biomass, biogas, geothermal, solar thermal including storage facilities, and highly efficient co-generation of heat and power plants) renewable energy projects. The type and contents of the FiPC, as well as the conclusion procedure, will be set out in a Ministerial Decision on the proposal of LAGIE and the opinion of the Greek Regulatory Authority for Energy.

The duration of the Operating Aid is 20 years for all RES and HECHP technologies, apart from small rooftop PV installations up to 10 kW and CSP installations for which the duration is set to 25 years.

The new Support Scheme in a snapshot.



The RTs for all renewable energy technologies and categories of projects stipulated in the new Law, other than solar PV with an installed capacity more than 500kW, are set administratively for 2016 (remaining however, applicable for the term of the relevant FiP or FiT Contract signed in 2016).

Table 4: Reference Tariffs of Law 4412/2016, Table 1 of Article 4.1(b)		
Renewable technologies and project categories	**RT (€/MWh)**	**Project IRR**
Onshore wind parks in the Interconnected System	98	9%t
Onshore wind parks in the Non-Interconnected Islands	98	9%
Small hydropower ≤ 3MW	100	9%
Small hydropower > 3MW and ≤ 15MW	97	9%
Solar PV < 0.5MW [*Roof-top solar PV installations are regulated by special legislation and hence excluded from the present briefing.*]	1,1 * wholesale electricity market price of the previous calendar year	-
Solar PV ≥ 0.5MW	Competitive bidding	-
Biomass (or bioliquids) from thermal processing ≤ 1MW (excluding the biodegradable fraction of urban waste)	184	9%
Biomass (or bioliquids) through gasification ≤ 1MW (excluding the biodegradable fraction of urban waste)	193	9%
Biomass (or bioliquids) from thermal processing (including gasification) > 1MW and ≤ 5MW (excluding the biodegradable fraction of urban waste)	162	9%
Biomass (or bioliquids) from thermal processing (including gasification) > 5 MW (excluding the biodegradable fraction of urban waste)	140	9%
Landfill gas and biogas from anaerobic digestion of the biodegradable fraction of urban waste ≤ 2MW	129	9%
Landfill gas and biogas from anaerobic digestion of the biodegradable fraction of urban waste > 2MW	106	9%
Biogas released from anaerobic digestion of biomass (energy crops, rural waste and residues, etc.) ≤ 3MW	225	10%
Biogas released from anaerobic digestion of biomass (energy crops, rural waste and residues, etc.) > 3MW	204	9%
Solar thermal without storage system (unless bioliquids are used, in which case see above)	257	9%
Solar thermal with storage system (minimum two hours) (unless bioliquids are used, in which case see above)	278	9%
Geothermal power ≤ 5MW	139	10%
Geothermal power > 5MW	108	10%
Other renewable energy technologies	90	10%

2.3 Natural Gas

Like in the electricity Market, RAE is proceeding with a natural gas market restructuring plan which is the implementation of the target model in the Greek wholesale gas market based on the European regulations, directives and guidelines. Currently, the Greek gas market is based on the execution of bilateral contracts between the (main) supplier of the importing natural gas (DEPA S.A) and its eligible customers (i.e. industries and retailers); no organized wholesale market exists yet. Transactions that have been recorded so far are the result of the following mechanisms: a) wholesale trade of LNG quantities in-tank, b) resale of gas to eligible customers, and c) the gas release (sale) program by DEPA S.A. per the provisions of the Hellenic Competition Commission (HCC) Decision 551/VII/2012.

A balancing services trading platform is planned by the Greek TSO to be operational in 2017. The launch of a balancing trading platform is taking place in response to the interim measures that were approved by RAE in 2015, based on the provisions of the European Network code on balancing. The operation of the platform will allow all shippers active in the market to trade their imbalance positions (demand-supply) and it is expected to increase the liquidity (transactions) in the Greek natural gas market.

The current state of the wholesale market.

RAE has repeatedly stressed that, under the current operating conditions of the Greek gas market such as: a) the lack of alternative suppliers of natural gas to the Greek market, b) the limited storage capacity of the transmission system, and c) the restrictions imposed by the existed importing supply contracts such as commitments on “destination clause” and on “take or pay clause”, DEPA’s commitment to its own gas release (sale) program is currently, the main option for gas supply to third parties - consumers and suppliers - and hence, currently, the only way possible to develop competition in the wholesale gas market, in Greece.

During 2015 and 2016, RAE provided an extensive opinion to HCC on ways to improve the operation of the gas release (sale) program in the framework of an extensive consultation run by HCC whereby all major gas market players participated in. Thus, to offer Suppliers and Customers the ability to put together a flexible portfolio for the supply of natural gas and in addition to the current system of quarterly auctions, DEPA has undertaken commitments to release part of its own natural gas on an annual basis through electronic auctions, i.e. with an absorption period of one calendar year (annual auctions). Additionally, to further reduce dependence of Customers on DEPA and to equally treat all market participants, DEPA undertook the commitment to make all quantities available through the annual and quarterly auctions solely at the Virtual Nomination Point (VNP) of the National Natural Gas System (NNGS), in 2015.

Transparency in the gas market.

RAE, within the framework of its competences regarding monitoring of the Greek energy market, is publishing data on the calculated Weighted-Average Import Price (WAIP) of natural gas in the NNGS, monthly (monthly review). The publication of data on WAIP, in combination with the publication of data on daily prices of balancing gas (HTAE) on the TSO's (DESFA) internet site, allows current and potential market participants to gain a better understanding of the price formation in the Greek market, and, therefore, to exploit business opportunities and enhance competition, to the benefit of consumers. Furthermore, the publication of wholesale prices constitutes a necessity, at a subsequent stage, of an organized competitive wholesale gas market. RAE presents the monthly WAIP against the daily price of balancing gas (HTAE) for the same month, as announced on the internet site of DESFA, from January through December. Data are published on RAE's website and updated on a regular basis (see ch.4).

Market participants' needs: absolute metric values.

The National Natural Gas System (NNGS) transports Natural Gas to consumers connected to the NNGS in the Greek mainland from the Greek-Bulgarian border, the Greek-Turkish border and the Liquefied Natural Gas (LNG) terminal, which is installed at Revithoussa island at Magara (Athens/Attica region). More specific, there are three entry points into the national gas system: 1) the entry point "Sidirocastro" (Greece-Bulgaria border) with an interconnection technical transmission capacity 121.600 MWh/day, 2) the entry point in "Agia Triada" (LNG terminal) with an interconnection technical transmission capacity 150.000 MWh/day and 3) the entry point in "Kipi" (Greece-Turkey border) with an interconnection transmission capacity 49.000MWh/day.

During the year 2016, the total natural gas deliveries at NNGTS entry points amounted to 44,7 TWh compared to 34,3 TWh in 2015 and to 31,8 TWh in 2014. Sixty four percent (64%) of total deliveries came from the interconnection point "Sidirokastron" (from Bulgaria), sixteen percent (16%) came from the interconnection point "Kipi" (from Turkey), and twenty (20%) percent from the LNG terminal station "Agia Triada" (i.e. deliveries at Agia Triada include LNG for balancing purposes).

Until recently, there was no considerable competition in imports of natural gas in Greece, as the share of DEPA gas imports corresponded to more than ninety percent (90%) of total annual imports. In specific, the share of DEPA gas imports in 2014 reached ninety-five percent (95%) of total annual imports, and ninety-two percent (92%) in 2015. Only one (1) other company (big industrial consumer), beyond DEPA, imported natural gas in the country in 2014 and in 2015, representing the remaining five percent (5%) in 2014 and eight percent (8%) in 2015 of total imports.

In the year of 2016, DEPA reduced its annual contracted quantity in the GazProm Contract and a new importer has become active in the Greek gas market. The effect of this change on the wholesale market is not yet evaluated by the Regulatory Authority but according to current estimates the share of DEPA gas imports may drop significantly (below eighty percent) because of this evolution in the year 2017 and onwards.

Identification and description of the steps that will be implemented to improve wholesale market functioning.

As defined in January 2015, ACER Document entitled: "European Gas Target Model-Review and Update" a wholesale gas market is defined as the sum of gas trading activities (including spot, prompt and forward) with delivery agreed at one specific point and concluded using a transparent trading venue (i.e. exchange, broker platforms). It should be noted that the main delivery points are the virtual points of the entry/exit systems. Distinct delivery points are considered as separate markets.

In order to establish a fully functioning wholesale gas market four main actions are needed: a) The establishment of a day ahead (transmission rights) capacity and product markets, b) The establishment of an intraday capacity and product market, c) The establishment of a forward capacity and product market, and d) The establishment of a balancing services market.

Several actions have been completed in the year 2016 along the four main actions above and more actions will be taken by RAE to promote sustainable competition and create a more liquid gas wholesale market in the year 2017 and onwards. We refer some of the actions below:

The interconnection Point Kulata-Sidirokastro Agreement (Greece-Bulgaria Border)

The Interconnection Agreement for the IP "Kulata (BG)-Sidirokastro (GR)" signed between the TSOs of Greece and Bulgaria, in June 2016. The active support of RAE and EWRC and the guidance by the European Commission, enabled finally commercial gas flows from Greece to Bulgaria starting the 1st of July 2016.

The Commission has welcomed the agreement as a crucial step towards implementing EU rules on one of the cross-border points within the EU where historic transit arrangements, dominated by a single company, prevailed. Therefore, thirty years after the operation of the interconnector (IP) Kulata-Sidirokastro (Greece-Bulgaria), there is currently an Interoperability Agreement (IA) in place for the operation of the IP according to the provisions of the Network code (NC) on Interoperability. The agreement strengthens the cooperation of the TSOs and the coordination of the two national transmission systems as well the ability of the two TSOs to implement the network code on capacity allocation (NC CAM) on the Interconnection point.

Implementation of NC CAM - Capacity auctions through the regional trading booking platform RBP

In 2016 both TSOs of Greece and Bulgaria selected the Regional Trading Booking Platform as their preferred capacity trading booking platform for the implementation of the European Network code on Capacity Allocation Mechanism (CAM) at the IP. The first capacity auctions for reserving capacity at the IP Kulata-Sidirokastro were successfully performed on the Regional Booking Platform on 9th December 2016.

No bundled capacity was offered since Bulgartransgaz S.A. announced zero capacity available on a firm-forward basis to the IP because all technical capacity at the Bulgarian side, in the flow direction BG→GR, has already been booked on a long-term basis. On the Greek side, all technical capacity of the IP minus 10% reserved for short term products was auctioned off. Nine six percent of the capacity offered on the Greek side was bided on and contracted by several shippers (105.000 MWh out of 109.196 MWh), indicating an increased participation of market participants in the capacity auctions compared to one shipper holding capacity on that point.

Further capacity auctions for quarterly, monthly and daily products are scheduled at the IP per the auction schedules announced on RBP, DESFA and Bulgartransgaz websites. In general, per the available data published on RAE's website in the National Natural Gas System Registry (NNGS) registry, including parties interested to ship gas in Greece, there is currently registered interest of fifty entities of which approximately fifteen to twenty have been active. The NNGS Registry is continuously being processed and updated by RAE.

Product trade at the Virtual Nomination Point

With the second amendment of the Gas Network Code in Greece in December 2013 to allow for the implementation of an entry-exit system and disentangle entry capacity booking from exit capacity booking a virtual nomination point (VNP) was established. The establishment of the VNP along with the proposal of the Greek Regulator for the quantities released by the incumbent DEPA to be offered at the VNP resulted in more trade taking place at the VNP in the last couple of years, as evidenced in the table below which has been submitted to DG ENER by the Greek TSO for the CESEC meetings and workshop that took place, in November 2016.

TABLE 5: TRADING VOLUMES AT THE VIRTUAL NOMINATION POINT

Trading volumes (in GWh)	Gas year 2015/2016	% change GY15-16/GY14-15	Monthly Average (for 12 months ending September 2016)	Monthly minimum (for 12 months ending September 2016)	Monthly Maximum (for 12 months ending September 2016)	Daily Average (for 12 months ending September 2016)	Monthly minimum (for 12 months ending September 2016)	Monthly Maximum (for 12 months ending September 2016)
OTC Spot (Day-ahead, Intraday)	19.562	**222**	1.630	883	2.760	53	15	108

TABLE 6: NUMBER OF TRADES AT THE VIRTUAL NOMINATION POINT

Number of trades	Gas year 2015/2016	% change GY15-16/GY14-15	Monthly Average (for 12 months ending September 2016)	Monthly minimum (for 12 months ending September 2016)	Monthly Maximum (for 12 months ending September 2016)	Daily Average (for 12 months ending September 2016)	Monthly minimum (for 12 months ending September 2016)	Monthly Maximum (for 12 months ending September 2016)
OTC Spot (Day-ahead, Intraday)	4929	**72**	411	342	499	13	8	17

Source: DESFA, Greek TSO

The trades/transactions were executed at the Virtual Nominations Point (VNP) according to Users' Daily nominations submitted to the TSO. Though the TSO has no information regarding the trades' period agreed between the Users. As evidenced by the referred data above this is the over the counter (OTC) spot (day-ahead, intra-day transactions) trade occurring among shippers at the Virtual Nomination Point. Per the provided data by the Greek TSO there has been a two hundred twenty two percent (222%) increase in the OTC trade volumes and a seventy two percent (72%) increase in the trade number from GY 2014/15 to GY 2015/16.

Balancing Network Code and a future Balancing market

At the end of the first quarter of 2015 DESFA submitted to RAE's interim measures report according to the provisions of Chapter X of the European Network Code on Balancing 312/2014 (NC on BAL), as the absence of sufficient (transactions) liquidity in the Greek natural gas market was not conducive to the full application of the provisions of the European Network Code on Balancing in 2015. RAE evaluated the interim measures report according to the provisions of articles 46 and 27 of the NC on BAL and approved the TSO's report with its 274/2015 Decision in September of 2015.

The proposed interim measures include the continuation of the existing balancing scheme, the creation of a balancing platform according to article 47 of the European network code on balancing (NC on BAL) that can evolve into a trading platform and further proposals in the regulatory framework with the purpose of alignment with the Balancing Regulation. The full implementation of the Balancing Regulation is expected on 16th April 2019 when NC on BAL shall enter full force. Therefore, in the meantime, the TSO has a primary role in balancing the system with balancing services acquired by a market-based procedure (international tender). All costs arising from the provision of balancing services are recovered by the TSO through relevant charges paid by the users, so that the TSO is cash-neutral. RAE is responsible for approving the balancing costs and the methodology for allocating these costs to the Transmission System users. All balancing charges and the methodology for their calculation, as well as the Daily Balancing Gas Price, are published on DESFA's website, in both Greek and English.

In the framework of the interim measures the TSO is planning to launch and operate a balancing services trading platform in the second semester of 2017. The operation of the platform will allow all shippers active in the market to trade their imbalance positions and increase liquidity in the Greek gas market. The TSO is also provided to participate in the balancing platform to acquire natural gas for balancing purposes and therefore increase liquidity on the platform. RAE is monitoring the implementation of the approved interim measures with the intention to have a full implementation of NC BAL by April 2019.

Natural Gas release (sale) program by the Public Corporation DEPA S.A., improvements.

Several necessary amendments were made on the gas release (sale) program of DEPA S.A. The authorities (the Ministry and RAE) completed the review of the gas release (sale) program by the Public Corporation of Natural Gas (DEPA S.A.), improving conditions of access for alternative suppliers and substantially increasing the quantities available. A written proposal by DEPA with revised commitments omnibus bill, i.e. improved access conditions and increased quantities up to 20% in 2020, was sent to the Hellenic Competition Commission (HCC) and was endorsed by HCC in the year 2016.

Identification and description of potential market reforms:

Unbundling, the separation of TSO from the incumbent; the legislation was adopted initially on 4th August 2016 (Law 4414/2016). Legislation will be amended, further facilitating the unbundling process: a) of the natural gas TSO (DESFA SA) by DEPA and b) the regional natural gas retail corporations (EPAs) – meaning the separation of the ownership and operation of distribution systems from the retail operation activity. With regard the Separation of EPAs from DEPA; RAE is working for the completion of this process. These actions will lead to the development of a wholesale market.

Strengthening the wholesale market by Opening the Retail market: decision on the free operation of the retail suppliers on the Greek territory meaning the termination of geographically defined areas of operation and of exclusivity supply rights (Law 4336/2015). The transition period to the new market organization started in 2016 (transition period 2016 -2018).

Infrastructure development as means for the wholesale market development:

a) Upgrade of the LNG Terminal of Revithoussa (LNG). Currently there are no storage facilities and the two storage tanks on the island of Revithoussa are used exclusively for temporary LNG storage. The Revithoussa LNG terminal remains the main channel/opportunity for the entrance of new market participants in the Greek gas market. The second upgrade of the Revithoussa LNG terminal is expected to be commissioned by 2018 and this will offer spare capacity for storage and trade in the Greek market.

b) A new Interconnection pipeline Greece – Bulgaria pipeline (IGB). A Market test (capacity offer) was organized by the ICGB AD (the company for the construction of IGB) to see the response of the potential market participants and it was successful. After the completion of the second stage of the market test, the Bulgarian and the Greek Regulators will evaluate company's application for exemption per the provisions of article 36 of the Gas Directive.

c) Trans Adriatic Pipeline development (TAP), the construction of (the Greek part) the Trans Adriatic pipeline (TAP) started on the Greek territory, in 2016. The Trans Adriatic Pipeline will be connected to the National Natural Gas System and therefore it opens the Greek market to natural gas being transmitted through TAP.

d) New offshore LNG Floating Storage and Regasification Unit (FSRU) near Alexandroupolis.

The project is part of the list of the European projects of common Interest (PCI) with an estimated capacity of 3-5 bcm/y. The realization of this project will grant the opportunity to Greece, Bulgaria and Romania to have access to new sources of natural gas supply from Qatar, Iran, Algeria, Israel, Egypt, Cyprus and USA. Gas supply diversification will strengthen the security of supply, will increase competition and will decrease prices of natural gas and electricity in the region.

Implementation of market reforms.

In 2015, Law 4001/2011 (implementation of Gas Directive 2009/73) was amended by Law 4336/2015 which promotes the reform of the gas market and supports the openness of the natural gas market in Greece through the removal of the monopoly power of the 3 regional distribution companies EPAs for an exclusive right of natural gas supply in the three main distribution areas in Greece. According to the new Law, by 1.1.2018, all customers in Greece become eligible and have the right to switch suppliers. The transition period to the new market organization started in 2016 (transition period 2016 -2018).

Expected state of wholesale market functioning in 2017

Based on the assessment of the current state of wholesale market operation and considering the key drivers towards improved wholesale market functioning, it is expected that the Greek gas wholesale market will not reach to the gas target model by 2017. But, there will be several improvements both in capacity market and product market liquidity (increase of transactions).

These improvements will be the result of: a) capacity auctions through RBP regional platform for the Interconnection entry point into the natural gas Greek system in Sidirokastro b) spare capacity available for trade in Agia Triada (LNG terminal in Revithousa interconnection point). c) the operation of a balancing platform by the Greek TSO where both DESFA and shippers will trade gas and imbalance positions.

Although the Greek gas market has not developed an intra -day market (a spot market), a day ahead market and a forward market yet, the Greek gas market has developed a well- diversified supply structure. Currently, the Greek market has three supply route sources with the prospects to add three additional supply route sources (i.e IGB/TAP/LNG terminal in Northern Greece). The increasing number of supply route sources shows a high potential for competition to develop in the domestic wholesale market.

With the operation of TAP pipeline in the year 2020 the Greek market will also be connected to the Italian market thereby allowing active trading of gas (including reverse flows) and the entrance of new suppliers in the market. By that year with the full implementation of the Network Codes the Greek gas market could be expected to reach the Gas target model.

3. Regulation and Performance of the Electricity Market

3.1 Network Regulation

3.1.1 Unbundling

One crucial foundation of the European Energy Law is the idea of unbundling, meaning separating out network management from energy generation and supply activities. The EU's third and last legislative package from 2009 introduced "ownership unbundling" for transmission system operators (TSOs – owners of high-voltage networks), but for distribution system operators (DSOs – owners of low-voltage or "last mile" networks), the third energy package maintains requirements for a weaker type of unbundling, "the legal and functional unbundling".

3.1.1.1 Certified Transmission System Operator - ADMIE S.A.

ADMIE S.A., the Independent Transmission System Operator (ITO) is a 100% subsidiary of the Public Power Corporation, PPC S.A. and is responsible for the development, operation and maintenance of the national transmission system, in Greece. Based on the Energy Law 4001/2011, the ITO model has been applied in the Greek market for the Transmission System Operator. In December 2012, RAE, with its final Decision 692A/2012 and after taking into consideration the Opinion of the European Commission, certified ADMIE as an Independent Transmission System Operator (ITO). ADMIE S.A. perform independently the three areas covered by the ITO model, namely: (a) the independence of management, (b) the independence of financial resources, and (c) the independence of operational activities. There was no change in the status of the ITO during 2016, despite Government's plans to privatize and/or terminate fully PPC S.A. ownership of ADMIE S.A.

3.1.1.2 Distribution System Operator - DEDDIE S.A.

The Hellenic Electricity Distribution Network Operator (HEDNO S.A. or DEDDIE S.A.), which is the independent Distribution Network Operator since May 2012, is a 100% subsidiary of PPC S.A. and is responsible for the development, operation and maintenance of the Hellenic Electricity Distribution Network (HEDN). PPC S.A. remains the owner of the Distribution Network assets (herein the "Distribution Network activity of PPC S.A."). HEDNO is also the Power System and Market Operator for the Non-Interconnected Islands of the country. There was no change in the status of the DSO during 2016.

3.1.1.3 Accounting unbundling

Per the provisions of the Energy Law 4001/2011 and the European Directive 2009/72, vertical integrated utilities are obliged to keep separate accounts and report unbundled financial statements (Balance Sheet and Profit & Loss Account) for each activity. The Regulatory Authority for Energy (RAE) approves the unbundling rules and methods, based on the company's proposal.

3.1.2 Technical functioning

Law 4001/2011 identifies ADMIE S.A. as the owner of the national transmission system. The national transmission system includes: a) high Voltage Lines, b) cross border interconnection Lines, and c) the total facilities and equipment necessary for the uninterruptible flows of electricity and security of supply into High Voltage lines of 150kV to 400kV, in Greece. In addition, the national electricity transmission grid includes projects of interconnection of the non - interconnected islands to the interconnected (mainland) system (i.e. subsea interconnections HVAC or/and HVDC). The total length of the national transmission system is 16.698km.

According to the Law 4001/2011, the owner of the national electricity distribution system is PPC SA (the incumbent). The distribution system includes: a) the lines of Medium and Low Voltage and few High voltage lines which are part of the distribution system, b) the total facilities and equipment necessary for the uninterruptible flows of electricity and the security of supply into Medium and Low Voltage lines, in Greece and c) the lines of the non - interconnected system of the islands. The total length of the distribution system is 237.248Km (2015).

3.1.2.1 Security and reliability standards, quality of service and supply

In what concerns Network Performance and Quality of Service, in December of 2010 RAE published an integrated set of Regulatory Instructions for the reporting of the Transmission System performance. Following these instructions, the TSO published reports on the performance of the Transmission System for the years 2010 till 2015. These reports provide availability indices for overhead lines, underground cables and autotransformers, as well as indices for the impact of the system unavailability to customers (system minutes) [3].

Performance and quality-of-service standards and obligations, as well as the respective monitoring processes, have not yet been set for the Distribution System Operator (DSO); therefore, currently, the DSO does not report any Quality of Service (QoS) indicators. Relevant requirements are to be developed under the umbrella of the Distribution Network Code. The proposal of RAE for the Distribution Network Code envisages a penalty/reward scheme for QoS regulation. The new distribution network code is expected to be applied in 2017.

In this new context, the role of the Regulator will include the followings:

- Setting, per regulatory review period, the regulated service quality dimensions, the corresponding overall and individual minimum quality standards, as well as the respective penalties/rewards, in conjunction with the allowed revenue for the distribution activity.
- Approval of rules, procedures and methodologies for monitoring, assessing and reporting service quality levels.
- Validation of data completeness and accuracy.

[3] Additionally, RAE participates in the annual CEER Benchmarking report on the quality of electricity and gas supply. These reports evaluate, in a comparative analysis, the technical functioning of the national electricity grids and of the natural gas transmission and distribution networks. See: "The 6th CEER Benchmarking Report on the quality of electricity and gas supply, in 2015", CEER Publication.

Until the Code is finally come into force in 2017, substantial preparatory work has already been completed. Review of the rules, procedures and data of PPC (that acted as the DSO until May of 2012), regarding QoS dimensions monitored to date, have been carried out by the Regulator since 2008. So far, this has allowed the Regulator to report on the overall service quality level (SAIDI, SAIFI, connection times, service at customer centers), based on available, non-audited, data provided by the DSO and to formulate and publish its opinion on them, as well as on current DSO practices regarding service quality monitoring and reporting, and on necessary improvements thereof. The new distribution code was developed and completed by RAE in cooperation with the Distribution System Operator (DEDDIE), in December 2015. The results of the second public consultation on the review of the Distribution code were published in the first quarter of 2016. In addition, the Regulatory Authority for Energy in cooperation with the other national regulators of the EU (CEER) are working together to ensure greater protection of consumers through guaranteed indicators with automatic compensation for the retail customers.

3.1.3 Network Tariffs for connection and access.

Network access tariffs in Greece are of the 'Postage Stamp' type, with the 'G' component (Generation component) being equal to 0% and the 'L' component (Load component) equal to 100%. Since 2011 (Law 4001/2011, article 140), RAE approves the tariffs for access to the national electricity networks (Transmission System and Distribution Network), one month before their entry into force, based on the proposals submitted to the Regulator by the Electricity Transmission System and Distribution System Operators (ADMIE S.A. and DEDDIE S.A, respectively).

3.1.3.1 Transmission Network operation:

<u>Network's operational Required Revenue and users/consumers' charges/tariffs:</u>

Developments regarding network company revenue regulation methodology in 2015/2016; In June 2014, following extensive public consultation, RAE approved the new methodology for setting the <u>TSO's allowed revenue</u> (Decision no 340/2014). The most critical changes, in comparison with the previous applied methodology (a cost-plus methodology)[4] are:

- A multi-year regulatory review period; the regulator sets the allowed revenue for 4 years, starting with a 3 years' regulatory period for the interim period 2015-2017, and following a 4 years' regulatory review period thereafter.
- Calculation of the TSO's Allowed Revenue based on real historic terms (not estimated).
- A Detailed methodology for the calculation of Return on Capital Employed based on real pre-tax Weighted Average Cost of Capital (WACC).
- Calculation of assets' depreciation using economic rules instead of accounting, assets' useful life.
- Smoothing the volatility of revenues within and between regulatory periods, to minimize the impact of such volatility to consumers' prices.

[4] "A cost-plus methodology": the regulator approves the annual cost of operation of a transmission network (or a distribution network) plus a reasonable profit (%) over the approved cost.

- Additional incentives for the investment in projects of major importance, particularly those which offer a significant benefit to consumers. Further details on the methodology can be found on RAE's webpage.

RAE's Decision (Ref no 404/2016), defined and approved the calculated TSO's annual transmission cost and TSO's required (operational) revenue at € 202,6 million (see table 7).

Table 7: Annual Transmission Cost and Required Revenue for 2017 in 000 Euro *	
	2017
Total Cost/ Allowed Revenue (AR)	260.966
Projects costs financed by third parties	7.596
Revenue for the use of the system in the previous year	-6.394
Clearing and depreciation	-3.426
Revenue from transmission rights	-45.749
Revenue from ITC mechanism	2.122
Revenue from non-regulated activities	-12.517
Tot Required Revenue (RR)	202.600
*to the closer integral number	

The approved return was based on the basic year (2014) values as follows:

- Regulatory Asset Value (Capital employed) of €1,398 m (including an estimate of €121.7m for new investments).
- Allowed Rate of Return (nominal, pre-tax): 8.5%.

In approving the Allowed Revenue, RAE validates the TSO proposal against historic performance and future trends. No formal methodology or benchmarking has been used in the cost assessment.

The total required revenue is then allocated to the different consumer categories. The methodology for setting charges (tariffs) on the use of the Transmission System (TUoS) for HV customers/users is set out in the System Operation Code, while the one for customers/users connected to the Distribution Network (MV and LV) is set out in a related Manual approved by RAE.

Tariffs for HV-connected customers follow a €/MW structure, charged on the customer's average hourly demand during the following three hours: system summer peak, system winter peak and the maximum of the two.

Transmission system cost is further allocated between MV and LV connected customers based on the contribution of each users/customers' category to the transmission system summer and winter peak demand.

For the purposes of the transmission system use charging (TUoS), the following four (4) customer categories are classified: 1. Medium Voltage (MV) customer, 2. Residential customer, 3. Residential customer with Social Tariff (KOT), 4. Other Low Voltage (LV) and Public Lighting Use LV, excluding Agricultural MV and Agricultural LV that have zero charges.

For MV customers, there is only a capacity charge (no energy charge for TUoS) based on the monthly maximum metered demand (MW) during peak hours (11am-2pm).

The Residential customers with Social Tariff (KOT) are charged a simple €/MWh energy charge (no capacity charge for TUoS). For Residential customers (except for Residential customers with Social Tariff), 10% of the allocated cost is recovered through capacity charges, which are charged based on the connection capacity (kVA), given the lack of metered demand (MW), whereas the remaining is recovered through a simple €/MWh energy charge.

For other LV customers, 20% of the allocated cost is recovered through capacity charges, which are charged based on the connection capacity (kVA) given the lack of metering (MW), whereas the remaining amount of the total cost is recovered through a simple €/MWh energy charge.

Based upon the above-mentioned classification, RAE's Decision Ref no 456/2016 approved the following tariffs for 2017 (see table 8):

Table 8: Regulated Tariffs applied for the use of the transmission system in 2017

Consumers Category	Capacity charge	Energy charge (cents €/ kWh)
Large Consumers HV	24.103 €/MW /per year	-
Consumers MV	1.3329 €/MW Peak time/ month	-
Households LV,	0,13 €/kVA per year	0,527
LV – Vulnerable customers	-	0,586
LV others	0,53 €/kVA per year	0,477

3.1.3.2 Distribution Network operation:

Network's Required Operational Revenue and users/consumers' charges:

In accordance with RAE's Decision 454/2016, RAE approved the total Required Revenue by the DSO (DEDDIE S.A) and its parent company PPC S.A. for the operation of the Distribution Network for 2017, as follows:

Table 9: Annual cost and Required Revenue for 2016

	PPC S.A (the owner)	DEDDIE S. A	Total
operating expenses		419.430	419.430
annual depreciation	124.416	8.000	132.416
Return (RAV*r)	197.456	14.472	211.928
Other (rent)	-10.092		-10.092
Total Cost/Allowed Revenue	311.780	441.902	753.682
Total Required Revenue	301.918	439.867	741.785

The approved return was based on the following values:

- Regulatory Asset Value (Capital employed) of €2,968m. (including an estimate of €292m for new investments).
- Allowed Rate of Return (nominal, pre-tax): 7%.

Distribution network operation cost is allocated between MV and LV connected customers based on the contribution of each class to the distribution network summer and winter peak demand.

For calculating charges on consumers using the Distribution System (DUoS), consumers are classified based on their connection voltage and metering capabilities. More specifically, consumers were classified into five categories: MV consumers, LV consumers with subscribed demand >25 kVA (with and without reactive power metering), LV residential consumers, and other non-residential LV consumers.

For MV consumers, 50% of the cost is recovered through a capacity charge and 50% through an energy charge. For residential consumers (households), 10% of the cost is recovered through a capacity charge and 90% through an energy charge. These percentages for the Other LV customers are 20% and 80%, respectively.

The final resulting "Use of the distribution System/ unit charges and consumption charges" in 2016, per consumer category, are presented in the following table 10.

Table 10: Regulated tariffs applied for the use of the distribution system in 2016		
Consumers Category	**Capacity Charge. (fixed charge per unit of consumption)**	**Energy charge (cents €/kWh)**
Consumers MV	1.179 €/MW Peak Demand /month	0,29
Consumers LV (over 25 kVA), based on the calculation of the maximum supply and taking into consideration the non-used power	3,78 €/kV agreed and charged per year	1,67
Consumers LV (over 25 kVA), based on the calculation of the maximum supply and non-taking into consideration the non-used power	3,17 €/ Kva Agreed and charged per year	1,9
Consumers LV	0,54 €/kVA Agreed and charged per year	2,13
Consumers (vulnerable customers)	-	2,37
Others LV (maximum 25 kVA)	1,47 €/kVA	1,9

3.1.3.3 Transmission network connection tariffs.

Only "shallow" connection costs, i.e. connection costs from the production plant site to the appropriate connection point of the Transmission System, are charged to producers. The charges are applied by the TSO, for specific tasks carried out by the Operator that are related to the connection works performed by the generators themselves (e.g. review of connection works studies, acceptance tests for built connection networks, etc.). Such charges have not yet been formally approved by the Regulator. Per the provisions of Law 4001/2011, a detailed price list is to be submitted by the TSO to RAE for final approval.

3.1.3.4 Distribution network connection tariffs

A methodology for setting connection tariffs has not yet been approved by the Regulator. The methodology is part of the Distribution Network Code which was approved by RAE in 2016 (Ref. no 395/2016), after conducting public consultation, during 2015.

3.1.4 Cross-border issues

Access to cross-border infrastructure including the procedures for the allocation of capacity and congestion management and the use of revenues for interconnectors:

In 2016, the interconnection capacity available for trade remain at a high level. The annual import interconnection electricity trading (inflows) decreased by -3,5% in respect to the total imported volumes of the previous year. The total exports (outflows) increased by 25% in respect to the total exported volumes in the previous year. However, the total scheduled imported volumes (10,9TWh) were much larger than the exported volumes in real terms (2,2TWh). The Net trading imports was - 8,7TWh in 2016 compared to the net trading equals to - 9,3TWh in 2015 (-8,46%), see Figure 1.

Table 11: Interconnection power capacity and scheduled trade in 2016

Description	Turkey	Albania	FYROM	Bulgaria	Italy	Total
Interconnections Voltage (kV)	1 line 400Kv	1 line 400kV, 1 line 150kV	2lines 400kV each	1 line 400kV	1 line 400kV (HVDC)	
Exported Energy (GWh)	795	386	212	292	518	2.204
Imported Energy (GWh)	187	1.859	2.617	4.091	2.211	10.966

The scheduled maintenance of the DC interconnector Greece – Italy that took place during the months October, November and December, the economic crisis in Greece and the imposed capital controls by the government, decreased the trends for further increase of the imported volumes. It must be noted that the interconnection (negative) imbalance had already increased significantly the previous years from 2,1 TWh in 2013 to 8,8 TWh in 2014 (+319%).

Table 12 presents the monthly performance of the import interconnection trading in years 2016, 2015 and 2014 and table 13 presents the cross - border allocation of the interconnection trading in 2016 and its performance compared to the year 2015.

Table 12: Monthly performance of the import interconnection trading 2016, 2015 & 2014. Total import interconnection trading (MWh)			
	2014	**2015**	**2016**
January	497.402	1.248.828	864.626
February	391.532	951.577	1.009.649
March	755.354	1.249.082	1.112.279
April	533.212	1.042.495	984.648
May	681.667	990.553	1.005.412
June	746.006	983,489	925.503
July	1.068.206	939.518	1.125.023
August	1.130.011	1.003.102	1.117.745
September	884.476	928.903	919.373
October	861.433	724.582	729.860
November	1.141.45	586.631	634.984
December	1.166.455	714.818	537.485
Total	**9.856.899**	**11.363.578**	**10.966.587**

Table 13. Cross border allocation of interconnection trading, (2016,2015)									
Import share									
Turkey		**Albania**		**FYROM**		**Bulgaria**		**Italy**	
2016	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**
1,71%	6,61%	16,95%	15,53%	23,87%	20,15%	37,31%	40,61%	20,16%	17,10%

Imports in real volumes from all countries, decreased significantly. The highest percentage share observed in the interconnection with Bulgaria, it was 37,3%. Imports from Turkey recorded the lowest percentage by 1,71%, while imports from FYROM, Albania and Italy percentage shares in total imports were 23,8%, 17% and 20% respectively.

Exports increased from 1,05 TWh in 2014 to 1,7TWh in 2015 (68%), to 2,2TWh in 2016 (25%), Tables 14 & 15

Table 14: Total export interconnection trading (MWh) , 2016 – 2015 -2014				
	2014	**2015**	**2016**	
January	41668	98336	161.563	
February	23535	70952	44.971	
March	32493	50191	58.222	
April	94329	72688	99.082	
May	82712	39974	92.375	
June	68011	71275	117.328	
July	73212	438313	229.501	
August	97889	347476	206.166	
September	114150	210450	237.229	
October	171813	131062	408.292	
November	145252	82932	210.395	
December	106281	152629	339.198	
Total	1.051.345	1.766.278	2.204.322	

Table 15: Export share									
Turkey		**Albania**		**FYROM**		**Bulgaria**		**Italy**	
2016	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**
36,09%	26,52%	17,51%	11,15%	9,65%	11,14%	13,24%	2,23%	23,51%	48,96%

Overall, the (net) trading volumes (flows) across borders decreased by 0,7 TWh (-8,46%, decrease), in 2016 compared to the previous year.

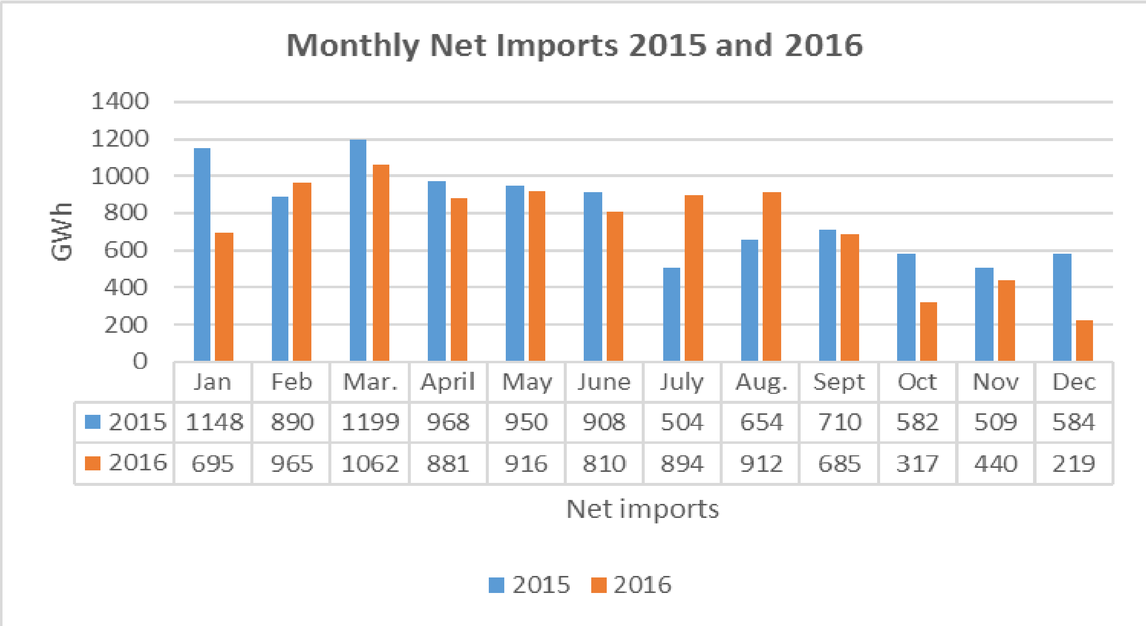


Figure 1 Monthly net transmission (trading) capacity imports.

The transmission capacity allocation rights for the Greece - Italy border, within the Central – South Europe (CSE) Region, are operated (since April 1st, 2011) by the Capacity Allocation Service Company (CASC S.A.), which also performs the capacity allocation functions for the Central Western Europe (CWE) Region borders. During 2014, RAE approved (Decision 653/2014) new Capacity Allocation Auction Rules for the borders with Italy, with amendments for promoting the further harmonization of auction rules.

With Decision 675/2014, RAE approved the Auction Rules in the borders with Albania, FYROM, Bulgaria and Turkey, which describe no significant change compared to the Auction Rules that were approved for 2014. These Auction Rules will be applied across the borders of Greece to Albania and Turkey until the Auction Rules of South East Europe Coordinated Auction Office – SEE CAO, which have been approved by RAE with Decision 475/2014, took effect in 2015. However, the Bulgarian Transmission Operator (ESO EAD) decided not to participate in SEE CAO; therefore, the Auction Rules approved by RAE remained unchanged in 2015 and 2016. Similarly, MEPSO (the Transmission Operator of FYROM) has not made a definitive decision yet concerning the participation in SEE CAO, hence the Auction Rules for the interconnection with FYROM were valid for the whole 2016.

At Greece – Bulgaria border; Common Transmission Capacity Allocation Rights' Rules are being applied at the cross - border Greece – Bulgaria interconnector since 2011 for joint auctions for the allocation of the total transmission capacity, with the Bulgarian TSO performing the monthly auctions, while the Greek TSO performs the yearly and daily ones, along with the secondary market management. The rules remained basically unchanged compared to the previous ones, approved for 2016.

Regarding Greece – Turkey cross border grids' interconnection: Greece – Turkey interconnector entered its commercial operation in June 2011, but full implementation of the 714/2009 EU Regulation has not been possible yet. Independent rules have been adopted for the capacity allocation, with the scheme of 50%- 50% management applied by the two national TSOs, and rules that are the same as the ones applied for Greece- Albania and Greece – FYROM interconnector. There are no yearly products, as the current trial operation phase of the interconnection does not ensure the actual availability of the rights. ADMIE manages the agreed net transmission capacity (NTC) in monthly auctions and, then, allocates in daily auctions only the monthly rights that were not declared (the Turkish TSO does not hold daily auctions). In April 2013, the ENTSO-E Regional Group Continental Europe (CE) decided to increase the capacities for commercial power exchanges between CE and Turkey. Hence, for 2015, the capacity for imports from CE to Turkey was 550 MW and the capacity for exports from Turkey to CE was 400 MW. According to the relevant agreement, these capacities are split by a ratio of 2/3 for the Bulgaria-Turkey border (266MW) and 1/3 for the Greece-Turkey border (133MW)[5]. The main principles of interconnection congestion management rules in 2016 remained the same as in 2015 in 2014 and 2013, namely:

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

[5] for more explanation see table 11.

Daily Physical Transmission Capacity Rights are firmed by the TSO. Under this scheme, during 2016 ADMIE S.A managed capacity allocation at the interconnection points and the flows' directions, as follows:

Table 16a. Capacity Allocation at Interconnections		
Counterpart Country	**Imports to Greece % of NTC***	**Exports from Greece % of NTC***
Bulgaria	100% yearly and 100% daily	100% yearly and 100% daily
FYROM	50%	50%
Albania	50%	50%
Turkey	50%	50%
Table HTSO responsibility for capacity allocation on interconnections		

*NTC: net transmission (trading) capacity.

Table 16b: Greece's cross border interconnections transmission capacity in 2016			
Interconnections	**Transmission lines power (KV)**	**Transmission Power Capacity (MW)**	**Transmission Trading Capacity (real) MW*.**
Greece - Bulgaria	1 line 400 KV	500 - 600MW	500MW
Greece - FYROM	2 lines 400Kv	2X (500-600MW)	0-250MW
Greece - Albania	1 Line 400 KV	500- 800MW	0-100MW
	1 Line 150KV	100MW	0MW
Greece - Italy	1 Line 400KV (HVDC)	500MW	500MW
Greece - Turkey	1 Line 400KV (HVDC)	500-600MW	130MW
Note: Trading available transmission capacity is lower than the nominal transmission capacity due to technical and legal barriers,			
*Transmission trading capacity are defined by the TSOs based on real flows (indicated year 2012)			

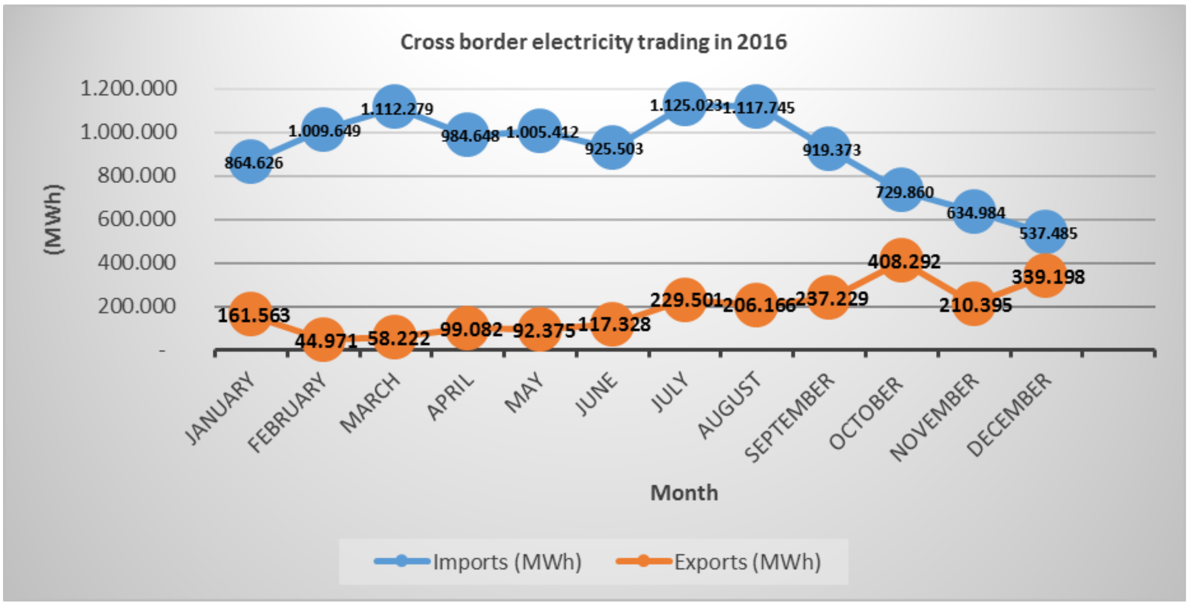


Figure 2. Cross border electricity trading in 2016 (scheduled flows, see real inflows in Figure 1)

3.2 Promoting Competition

3.2.1 Wholesale market

3.2.1.1 Description of the wholesale market.

The Greek wholesale electricity market is based on a pure day ahead mandatory pool mechanism. Generators, auto-producers and importers must state an offer price for each hour of the following day for their available capacity to supply electricity to the system. Currently a cap of EUR 300/MWh applies to all generators' offers. At the same time, all buyers of electricity; retailers, exporters pumped storage hydro and self- supplied consumers must submit demand declarations for each hour of the following day but, they do not submit price based offers. The day ahead market clears on an hourly basis according to a system marginal price (SMP), corresponding to the economic offer of the block lastly accepted in the economic merit order to meet demand.

The TSO runs the system using an algorithm which co-optimizes energy provision, ramping and ancillary services and runs at day ahead in real time. To address the load fluctuations (a rapid increase in net demand) the algorithm suggests calling upon fast ramping generation. These plants are obliged to operate to provide flexibility services to the TSO, remaining on a stand by at their minimum stable level, rapidly increasing or decreasing generation, and are therefore called to operate as "must run" plants. As lignite generation, has not sufficient ramping up capability, the system must be based on natural gas fired generation (in the older times in oil fired generation) and hydroelectric generation.

However, per the regulation in force the SMP of the wholesale market continues to be set by the lignite generation bid and not by the fast ramping plants, even for the hours during which the service is being provided, as these plants are viewed technically not as purely meeting electricity demand but rather as discharging a specific service.

The Greek wholesale electricity market continue to operate as a day ahead mandatory pool mechanism since its inception in 2005, to allow competition to emerge in a context with a severe constraint up to now: no structural reforms were implemented about PPC, the incumbent vertically integrated monopoly utility, such as plant divestments or consumer release, as elsewhere in Europe. The incumbent (PPC), remains dominant in both the generation and retail sectors, retaining exclusive access to cheap lignite and hydro resources, while retail prices, despite the gradual removal of cross-subsidies, were not linked to wholesale costs, but rather regulated at PPC's average cost, to transfer the benefit of the generator surplus to consumers. This combination of market features posed severe obstacles to new entry in the early years of market liberalization, giving a strong signal for upcoming capacity shortages in the following years.

The current market design (the mandatory pool) incorporates two distinct "settlement processes":

- The day-ahead market, in which generators' payments (suppliers' charges) are calculated, based on the System Marginal Prices (SMP) and the plant schedules derived from the day-ahead dispatch (load declarations submitted with a gate closure one day ahead of real time).

- “The settlement of imbalances”, in which deviations from day-ahead schedules are charged or compensated, based on the Marginal Imbalance Price (IMP/OTA), depending on whether they reflect the TSO dispatch orders (the real operated time) or plant-specific reasons. The marginal Imbalance Price (IMP) which is the Diverted marginal price distinguished by the System Marginal Price of the day ahead market, it can also be called as the operating marginal price of the system.

In the non-interconnected islands, 32 autonomous power systems currently operate without any wholesale electricity market. In all these autonomous power systems, the Public Power Corporation (PPC) is the only conventional power producer using oil and heavy diesel as a fuel. There are several RES power producers (including a PPC subsidiary) but only one existing supplier (PPC) in all islands, except Crete where the market is open to other suppliers from June 2016. The network operator in the non - interconnected islands is DEDDIE SA (Hellenic Distribution Network Operator). In the non - interconnected 32 autonomous systems, neither producers or suppliers submit daily offers for their production or for their customers loads thus, there is no system marginal price but an estimated clearance price of energy. The estimation is done monthly, based on the variable cost of the conventional power units for each of all these autonomous power systems, pursuant to Law 4001/2011 and the code of micro-grid operation of the non - interconnected islands, PPC as the only supplier buys all electricity including RES.

3.2.1.2 Installed Capacity and Generation

The capacity certificates introduced in 2006 created incentives for new investment, which turned out to be adequate. More specifically, following the introduction of the Generation Capacity Adequacy Mechanism (CAM), 2024 MW of new, IPP gas capacity was added to the system by the end of 2012, whereas in March 2013 a new CCGT plant by PPC also granted the status of commissioning. In 2014, there was only a small increase in installed capacity given the commissioning of a new PPC 155MW hydro plant (iIlarionas). In 2015, there was an increase in installed capacity of natural gas plans from 4906MW in 2014 to 5751 in 2015 (mainly due to a rise of PPC CCGT units installed capacity). In 2016, there was a decrease in the lignite installed generation capacity from 4.456MW to 3.912MW and the final closure of the oil generation units of PPC (698MW). For the same period RES performed only a small increase in the installed generation capacity, from 4464MW in 2014 to 4594MW, in 2015 to 4872MW, in 2016 (see Table 17).

Table 17. Installed Capacity by Producer/Fuel				
By producer/fuel	**Installed Capacity 2016 (MW)**	**Installed Capacity 2015 (MW)**	**Installed Capacity 2014 (MW)**	**Installed Capacity 2013 (MW)**
PPC Lignite	3912	4456	4456	4456
PPC Hydro	3173	3173	3173	3018
PPC CCGT	2669	2843	1998	1998
PPC OCGT	0	339	339	339
Elpedison CCGT	799	799	799	799
Heron II CCGT	422	422	422	422
Korinthos Power CCGT	434	434	434	434
Protergia CCGT	433	433	433	433
Heron I OCGT	148	148	148	148
Alouminion CHP	334	334	334	33
PPC Oil	0	698	698	698
Total Thermal+Large Hydro	12.323	14.077,9	13.232,9	13.077,8
Renewables	4872,5	4593,5	4463,2	4295,2
Total	17.196,5	18671,4	17696,5	17373

Table 18. Installed Capacity by Fuel				
By fuel	**Installed Capacity 2016 (MW)**	**Installed Capacity 2015 (MW)**	**Installed Capacity 2014 (MW)**	**Installed Capacity 2013 (MW)**
Lignite	3912	4456	4456	4456
Natural Gas	5239	5751	4906	4906
Oil	0	698	698	698
Hydro	3173	3173	3173	3018
RES	4873	4594	4464	4295
Total	17.197	18671,4	17696,5	17373,0

Table 19a. Installed Capacity and Production, including RES, in 2016.					
Installed capacity and production by producer and by fuel, in 2016	**Installed capacity (MW)**	**Total annual production (GWh)**	**Share in produced volume (%)**	**Share in produced volume including RES (%)**	**Capacity factor (%)**
PPC Lignite	3912	14898	44,65%	34,2%	43,4%
PPC Hydro	3173	4843	14,52%	11,10%	17,4%
PPC CCGT	2669	5603	16,79%	12,8%	24,0%
PPC OCGT	0	0	0,00%	0	0
Elpedison CCGT	799	2488	7,46%	5,71%	35,5%
Heron II CCGT	422	1343	4,03%	3,08%	36,3%
Korinthos Power CCGT	434	1563	4,68%	3,58%	41,1%
Protergia CCGT	433	1475	4,42%	3,38%	38,8%
Heron I OCGT	148	5,1	0,02%	0	0,3%
Aluminum CHP	334	1145	3,43%	2,62%	39,1%
PPC Oil	0	0	0,00%	0%	
Other		0,976	0,00%	0%	
Total Thermal+Large Hydro (1)	12.323	33.367	100%	76,5 %	31%
Total RES (Grid + Network) (2)	4873*	10.191		23,5%	24%
Total (1+2)	17.197	43.558		100%*	29%
To the closer integral					
Including Aluminum Generation					

Monthly production by Generation fuel in Greece, in 2016													
	Jan	Feb	Mar	Apr	May	June	July	Aug.	Sept	Oct	Nov	Dec	Total
Lignite	1679	1167	1016	792	875	984	1485	1368	1181	1270	1396	1687	14900
Natural gas	1065	691	701	726	745	1318	1280	1037	1030	1192	1095	1633	12513
Hydro	396	314	514	423	343	463	503	420	281	326	382	478	4843
RES	804	825	892	850	863	845	937	984	763	755	786	887	10191
Total	3944	2997	3123	2791	2826	3610	4205	3809	3255	3543	3659	4685	42447
Note: excluding Aluminum S.A generation 1100 GWh for the year 2016.													

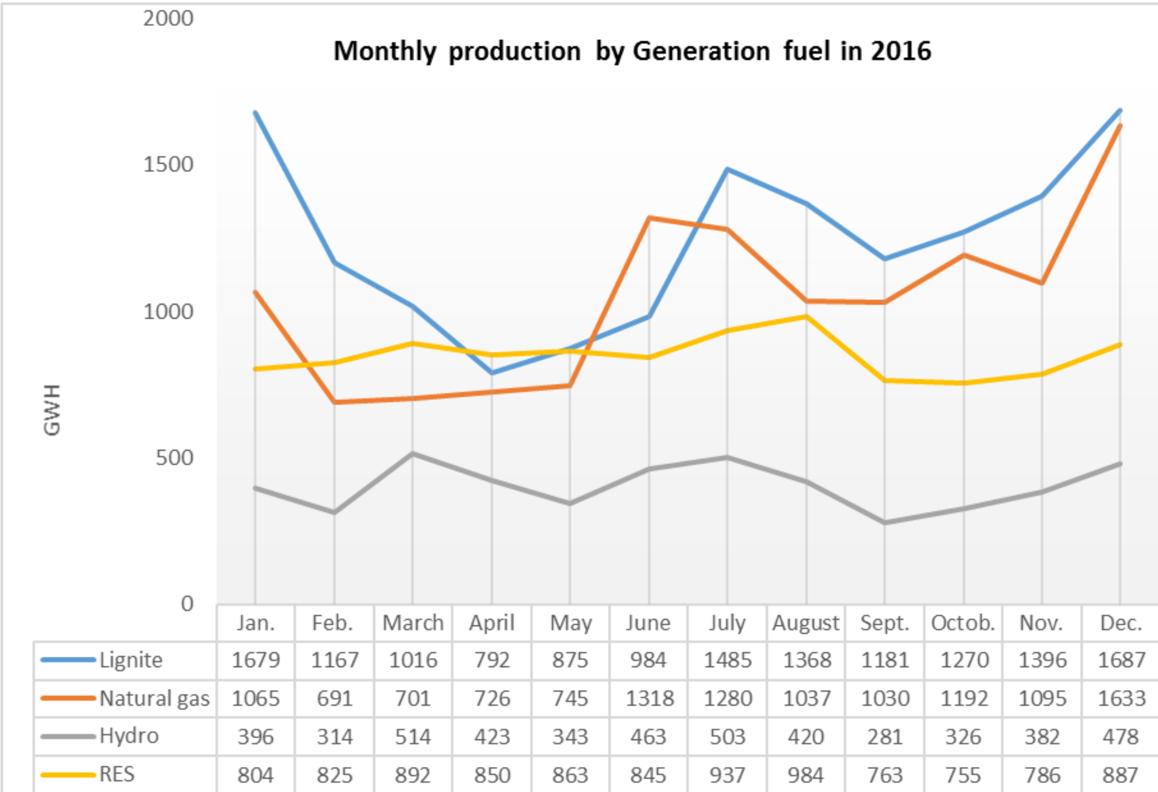


Figure 3. Monthly Production by Generation Fuel in 2016

Early projections for strong and prolonged growth of electricity demand (around 2.5% annually) were disrupted in 2009, when demand sank by 7% in a single year, due to the erupting economic crisis, and has not recovered since then. Hence, a substantial capacity surplus has emerged, with limited export possibilities and limited cost-reduction flexibility. In addition to diminished demand levels, the increasing penetration of renewables steadily curtails gas generation to an extent that may even expose them to the take-or-pay penalties set in their gas supply contracts. Following the formation of the Market Operator (LAGIE) and the System Operator (ADMIE) in February 2012, and the allocation of tasks between these two companies, the core of the market design and the settlement process involved remained unchanged during 2014 and 2015, while supply support mechanisms (capacity mechanisms) were refined to lead to more competitive market outcomes and reduce operational inefficiencies that had emerged.

As we have already referred, the current market design (the mandatory pool) involves two distinct settlement processes:

- The settlement of the day-ahead market, in which generators' payments (suppliers' charges) are calculated, based on the SMP prices and the plant schedules derived from the day-ahead dispatch (load declarations submitted).

- The settlement of imbalances, in which deviations from day-ahead schedules are charged or compensated, based on the Imbalance Price, depending on whether they reflect the TSO dispatch orders or plant-specific reasons.

There is also a provision for imbalance penalties, if certain limits are violated, regarding the magnitude and the frequency of the deviations. It should be noted that the System Marginal Prices (SMP), computed by LAGIE, and the imbalance prices, computed by ADMIE, are derived by solving the same cost-minimization algorithm with respect to the same technical and network constraints, based on the offers and bids submitted by generators and suppliers. In the former case, the values inserted for the various stochastic inputs (demand, plant availabilities and renewables output) are declared (day-ahead expected) values, while in the latter case, they are actual, metered, values. In the day-ahead market, uniform pricing still applies, reflecting the offer of the most expensive unit dispatched to provide energy (and not reserves), so that predicted demand is satisfied along with plant technical constraints and reserve requirements. Zonal pricing, intended to reveal congestion problems and signal the location for new capacity, has not been activated yet, although two zonal prices (for northern and southern Greece), applicable to generators, are explicitly derived, currently only as an indication. Participants may enter bilateral financial contracts (CfDs), but physical delivery transactions are constrained within the pool and related contracts do not exist. At the same time the lowest offer accepted on all generators (lower) offers to the mandatory pool (the day ahead market) equals to the defined variable cost of every generation unit of the generator.

Table 20: Day ahead market schedule and imbalances positions settlement of the market participants									
	DAY AHEAD SCHEDULE			IMBALANCES			TOTAL		
NAME	QUANTITY (MWh)	AMOUNT (€)	price (€/MWh)	QUANTITY (MWh)	AMOUNT (€)	Price €/MWh	METERED PRODUCTION (MWh)	TOTAL AMOUNT (€)	AVERAGE PRICE (€/MWh)
ELPEDISON S.A (CCGT)	2.528.359	113.009.829	44,7	-71.454	-774.534	10,8	2.488.455	-112.235.296	45,1
PROTERGIA POWER S.A. (CCGT)	1.519.613	69.875.753	46,0	-46.803	-737.695	15,8	1.475.216	-69.138.058	46,9
ALUMINIUM S.A	1.125.302	48.163.066	42,8	19.247	908.396	47,2	1.145.594	-49.071.462	42,8
PPC	24.578.497	1.086.206.746	44,2	341.022	21.831.639	64,0	25.344.903	-1.108.038.385	43,7
HERON I (CCGT)	1.655	82.799	50,0	3.442	316.619	92,0	5.102	-399.418	78,3
HERON II (CCGT)	1.406.122	63.627.426	45,3	-64.491	-1.734.522	26,9	1.343.770	-61.892.904	46,1
KORINTHOS POWER A.E. (CCGT)	1.654.910	74.851.983	45,2	-94.019	-2.322.576	24,7	1.563.239	-72.529.407	46,4
TOTAL	**32.814.457**	**1.455.817.602**	**44,4**	**86.943**	**17.487.327**	**201**	**33.366.279**	**-1.473.304.929**	**44,2**

3.2.1.3 Auxiliary and Generation capacity reserves mechanisms (market).

Due to the dominant position of PPC in the wholesale market and RES increasing share in generation, additional capacity generation mechanisms have also been introduced by the Regulator for the efficient operation of the market. Auxiliary and capacity generation mechanisms exerted a substantial impact on market outcomes, but were revised during 2013, 2014, 2015 in crucial aspects so as yield to more competitive outcomes.

The following rules of auxiliary and reserve capacity generation mechanisms (henceforth the supply support mechanisms or supplementary mechanisms) were revised during 2013, 2014, 2015 and 2016:

- *A lower limit is imposed on generators' offers*, equal to the minimum variable cost of each unit in each trading period. This limit had been introduced because, in the current structure, the incumbent has a strong incentive to suppress wholesale prices. An exception to the previous rule is the so-called "30% rule", which allows generators to offer 30% of their plant's capacity at a price below its minimum variable cost, if the total weighted average of their bids is still at or above their minimum variable cost. The “30% rule” was abolished on 31.12.2013.

- *A price cap offer.* A cap of 150 €/MWh has been imposed on all generators’ offers up to 2015. With a new decision RAE, has increased the imposed cap on all generators’ offers: from 150 €/MWh in 2015 to 300 €/MWh in 2016.

- *A cost-recovery mechanism* ensures that generators dispatched by the TSO, beyond the day-ahead schedule, are remunerated based on their declared minimum variable costs plus a margin. This margin had been set previously to 10%, but it was abolished in July 2013, being considered a market distortion, as generators used the mechanism to get dispatched over prolonged time intervals, exhibiting stable profiles (of limited sensitivity to the demand level), but imposing unnecessary costs on the system. After this distortion was corrected, the mechanism better expressed its objective as a safety net that averts producers’ losses when dispatched due to reserve requirements (not necessarily energy balance requirements) and inter-temporal technical constrains. Nevertheless, the mechanism was removed on 01.07.2014. In 2015 however, RAE evaluated the implications of the mechanism abolition and with its Decision 392/2015, (re)introduced a more stringent version of the cost recovery mechanism.

- *A Generation Capacity Adequacy Mechanism (CAM)* is applied for the partial recovery of capital costs of generating plants, with suppliers being obliged to buy capacity certificates from generators. In 2014, the value of these certificates remained regulated, due to the very high market share of PPC in the retail market (>97%) and the consequent lack of liquidity and ability for contracting between suppliers and generators. The value of the capacity certificate was set in July 2013 from 45,000 €/MW/year (a level set back in November 2010) to 56,000 €/MW/year. The transitory regulated mechanism expired 31.12.2014 and in line with the recent European Guidelines a new market-based methodology (Transitory Flexible Remuneration Mechanism, TFRM), was elaborated in 2016.

3.2.1.3.i *Provisions of Balancing Services.*

The Imbalance Settlement Mechanism. Balancing is not performed through a separate balancing market, but as an extension of the day-ahead market (a second submarket), through the Imbalance Settlement Mechanism, per the following rules:

- All imbalances – referring to deviations between the day-ahead schedule and the real production or withdrawal of electricity – are settled through the Imbalance Settlement Mechanism.
- The imbalance settlement is conducted for each hourly trading period.

- During real-time operation, balancing energy is provided by the responsible body, based on the economic merit order of the offers that are submitted by the committed units on the day-ahead market.
- As soon as the relevant meter measurements are available, the imbalances are settled. Without explicit reference to technical details, the main concept is that each imbalanced party pays or receives an amount, depending on whether it injected or withdrew energy from the System, considering whether the change of its output compared to its day-ahead schedule is consistent with the TSO's instruction, or is caused due to other, plant-specific reasons. The final amount is mainly determined by three (3) parameters: a) the ex-post clearing price, b) the imbalance quantity (TSO instructed or not), and c) the real (metered) quantity.
- The ex-post clearing price results from the re-run of the day-ahead scheduling algorithm under the realized values of the stochastic variables and corresponds to the "Market Clearing Price" (i.e. uniform price).
- Moreover, a cost recovery mechanism is included, to ensure that generators will receive at least their marginal cost whenever they operate. The objective of the imbalance mechanism setting is to minimize the total cost of operation of the System, while reimbursing plant flexibility

The Balancing Settlement is performed by the TSO. Under certain circumstances (emergency cases), it is possible to use "balancing energy" from abroad, by using the residual capacity of interconnectors.

In view of the EU Target Model implementation, RAE is elaborating the necessary market design changes, including the introduction of intra-day and balancing markets.

3.2.1.3.ii *The market (mechanisms) for auxiliary services and capacity generation reserves, explained.*

The market for auxiliary services and capacity generation reserves usually called as the "supply support mechanisms" (or supplementary mechanisms) for balancing services. Capacity mechanisms are measures taken by Member States to ensure that electricity supply can match demand in the medium and long term. They are designed to support investment to fill the expected capacity gap and ensure security of supply. Typically, capacity mechanisms offer additional rewards to capacity providers, on top of income obtained by selling electricity on the market, in return for maintaining existing capacity or investing in new capacity needed to guarantee security of electricity supplies. Capacity mechanisms can potentially support not only power generation but also demand response measures (e.g. incentives to households and businesses to reduce electricity consumption at peak times). Therefore, Supply support mechanisms are mechanisms that support the supply of electricity to the grid and provide balancing services (see previous section: Provisions of Balancing Services). The mechanisms support the conventional power generation units through the generation capacity Reserve requirements and generation cost recovery guarantees. They are based on market rules (i.e.

auctions) and regulations (i.e. regulated reference prices and regulated quantities). In Greece, the supply support mechanisms (the Cost Recovery Mechanism and the Transitional Capacity Assurance Mechanism), have been revised in crucial aspects in 2015, to yield to more competitive outcomes taking the form of a Transitional Flexibility Remuneration Mechanism (FRM) in 2016. The supply support mechanisms exert a substantial impact on market outcomes (for more see the section: price monitoring).

Historic evolution of the supply support mechanisms:

With regards to the Cost Recovery Mechanism, the full elimination of the mechanism itself was already announced in the context of RAE's Decisions 338 and 339 of July 2013, to be effective from mid-2014. However, after the abolishment of the "30% rule" (for the submission by generators of bids below the minimum variable cost) in the afore mentioned context from 01/01/2014, RAE has been monitoring the evolution of the mechanism during the first semester of 2014, conducting a relevant analysis and asking ADMIE as well as LAGIE to submit their comments on it, and particularly on four alternatives for the reform of the mechanism. Moreover, ADMIE was asked to conduct a special study on the impact and implications the elimination of the Cost Recovery Mechanism could have in the wholesale market, while the participants were invited to inform RAE, through specific reports, about any effects this elimination could have on their operation. In January 2015, ADMIE submitted the requested technical report and RAE proceeded in 2015 with the re-evaluation of the mechanism, taking also into account the reports sent by the market participants. In its Decision 392/2015, RAE introduced a more stringent set of criteria for Units to be eligible for the Cost Recovery Mechanism. More specifically and to limit the cost of the mechanism and avert abusive strategies, while ensuring, simultaneously, that predatory effects are minimized, and given the limited scale of reserves compensation in the current co-optimization model, the mechanism is applied in the following cases:

(i) For those Units, dispatched in real time following the System Operator's (ADMIE) Dispatch Instructions but not selected in the Day Ahead Market (DAM) scheduling.
(ii) For those Units selected in the DAM for reserve requirements.

It must be noted that this Decision is of a transitory nature and of a limited time frame until the re-organization of the Greek electricity market takes place.

With RAE Decision 474/2014 the Transitional Capacity Assurance Mechanism (CAM) was extended until 31.12.2014, to smoothly proceed in 2015 with the implementation of the new scheme, which was notified to DG Competition in December 2014. More specifically, at the end of July 2014, and in the context of restructuring the CAM, RAE launched a public consultation on a high-level proposal considering the new Guidelines on State aid for environmental protection and energy 2014-2020, as well as the relevant documents issued by the European Committee. The purpose of the CAM was described as twofold: a) to ensure long-term capacity availability, and b) to address market failures, due to structural issues and power concentration. Taking into consideration the high RES penetration, that is expected to increase further, and the special system needs that follow it, RAE's proposal was based on the of identification of the generation capacity availability characteristics that are defined as system requirements. After integrating the comments from the first consultation and comments from the discussions with DG Competition, RAE launched a second public consultation in January 2015, with a proposal for a Transitional Flexibility Remuneration Mechanism (FRM), setting also the high-level design for the permanent auction-based FRM, while in parallel, the Greek Government notified the scheme of the Transitional FRM to DG Competition. For a smooth integration in the market, the Transitional FRM will not exceed 12 months (see section 3.3.2.2).

Following the disclosure of the above mechanism, RAE, firmly and consistently contributed to the evaluation process by the European Commission, responding with promptness in repeated requests to provide additional information and to clarify relevant data

In this context, considering the connection of the adoption of this mechanism with the commitments by Greece to reform various aspects of the wholesale electricity market, RAE took the initiative to set up an expert group, consisting of members of the Authority, the System Operator and the Market Operator, which refined the relevant commitments and constructed a roadmap for their implementation. These commitments will be implemented, considering studies' results about the impact assessment in preparation of the following measures in the Greek market:

- Increase the maximum bid price limit of the Day Ahead market Schedule (DAS).
- Require Statements of availability of hydroelectric power plants.
- Increase the limit of the secondary backup offers.
- Introduce a Pricing Methodology for the hydroelectric plants.
- Compensate the tertiary reserves

- Re-evaluate the framework of charges for electricity exports to charges of the Uplift Accounts. (settlement accounts from market clearing – i.e. imbalance settlements in the wholesale market of the day of the system operation).

Furthermore, RAE fulfilled its commitment to reassess the framework of charges for electricity export with its Decision 471/2015 according to which, from 01/01/2016 exports are exempt from the charges of the Uplift Account UA-2, UA-5 and UA-6, because these charges are not directly related to an inherent and integral part of the production costs themselves for exported electricity nor concern financial costs such activity is causing or likely to cause, by direct causation, the Transmission System Operator.

For the permanent Generation Capacity (Reserves) Mechanism, whose implementation is the responsibility of Greece in accordance with the provisions of paragraph 4.3 of Section III of Article 3 of Law 4336/2015 (Government Gazette 94 / 09.14.2015). As it has already referred above, RAE in 2015 set up a relevant Working Group RAE which in cooperation with the ADMIE analyzed the options for the design of the new mechanism. The objective was agreed on the basic principles of the mechanism and was released for public consultation and pre-notification to the European Commission (DG D / Directorate of Competition) to implement the mechanism within the 2016.

- The determination of the opportunity cost of hydro resources, explicitly linking this cost to reservoir levels and to the cost of the substitution fuel mix, as its main parameters. The development of a related methodology started in 2013 through a close collaboration between RAE and the Market Operator, LAGIE, and continued in 2014. The methodology, as modified in 2013, based on the results of LAGIE's simulations, was set to public consultation by RAE between 13.12.2013 and 20.01.2014. After evaluating the comments submitted during the public consultation, and taking into consideration additional analysis and comparative calculations, LAGIE adjusted the methodology, to account also for the recent regulatory reforms, and a second consultation was launched by RAE on 15.12.2014 until 15.01.016. A decision is expected in 2016.
- The modification of the Transmission Network Code and the Market Operation Code was focused on: a) harmonizing them with the provisions of the Non-Interconnected Island Power Systems Management Code, particularly in regards with PSO charges as well as the special account of Article 143 of L.4001/2011 (RES Account), and b) clarifying their provisions with regards to the unit reimbursement, the calculation of critical hours, the availability estimation of dispatched High Efficiency Heat-Power Cogeneration Units, the parameter approval.
- Continuous monitoring of the liquidity (the level of transactions) across the electricity supply chain. In 2015, the liquidity conditions in the domestic energy market remained extremely critical, due to the overall adverse conditions in the Greek economy in general and the continuous severe lack of financing and credit for the energy industry. The core problem remains the unpaid receivables of PPC: as the dominant supplier (retail market share >98%), the rate by which PPC collects its receivables has a major impact on the whole electricity value chain and the relevant cash flows. In 2015, despite its efforts to improve its collection procedures, eventually, PPC was not able to improve its rate and at the end of 2015 it estimated unpaid receivables of €2.4. Regulatory measures regarding the above issues were either adopted during 2014 or carried over to 2015 via public consultations or reviewing processes. The implementation of market reforms, along with further elaboration of their key features, will continue in 2016.

In 2016, the European Commission approved finally a Transitional Flexibility Remuneration Mechanism (FRM) for one more year as a transitional measure to the target model C (2016)1791 final/31.03.2016. With the law 4389/2016, the approved by the European Commission Transitional Flexibility Remuneration Mechanism (FRM) was transposed into the Greek legislation (see section 3.3.2.2). Per Law 4389/2016 and the commitments of the national authorities to the European Commission for the transitional character of the FRM in the domestic wholesale market, RAE in cooperation with ADMIE SA had to proceed to:

e) amendments to the network code
f) amendments to the market clearing procedures
g) establish a list of eligible generation units for participation in the mechanism
h) establish a methodology of imposed sanctions.

In this context, considering the connection of the adoption of this mechanism with the commitments by Greece to reform various aspects of the wholesale electricity market, RAE took the initiative to set up an expert group, consisting of members of the Authority, the System Operator and the Market Operator, which refined the relevant commitments and constructed a roadmap for their implementation. These commitments will be implemented, considering studies' results from about the impact assessment in preparation of the following measures in the Greek market:

- Increase the maximum bid price limit of the day ahead market scheduling (DAS).
- Require Statements of capacity generation availability of hydroelectric power plants.
- Increase the limit to the secondary backup offers.
- Introduce a pricing Methodology for the hydroelectric generation.
- Compensate for the tertiary reserves
- Re-evaluate the framework of charges for electricity exports to charges of the Uplift Accounts (settlement accounts from market clearing – i.e. imbalance settlements in the wholesale market of the day of the system operation).

(for the capacity generation mechanisms see also sections: 3.3.2.1, 3.3.2.2, 3.2.3)

The implementation of the capacity mechanisms including the demand response mechanisms, is a learning process for all actors, with several open questions such as how capacity reserves held abroad, and thus interconnection capacity, can be considered and how the level of the estimated peak capacity will need to evolve over time. Currently (2017), the European Commission has opened an in-depth investigation to assess whether German plans to set up an electricity capacity reserve comply with EU state aid rules. The Commission has concerns that the measure may distort competition and favor power plant capacity reserves' operators over demand side response operators. Similarly in Italy; critical points raised by the competition directorate within the European Commission in recent discussions with the Italian regulator include: the mechanism to determine the bidding curve at the capacity market auctions, and b) the modality in which demand side response will be able to take part in the auction, the participation of capacity located beyond Italy's borders (admit to the scheme with less favorable conditions) , the level set for the strike price of the reliability call options around which the Italian capacity market would be designed (June 2017).The level of the strike price is key. Setting it at the costs of an OCGT or a lignite unit or a unit would have a direct impact on the way prices are formed on the spot markets. However, Regulators have usually underlined that strike price will be "technological neutral". The year 2018 has been indicated as the starting year for a permanent capacity market mechanism, in Greece.

3.2.1.3.iii *Electricity Producers' Cost from natural gas due to fines in the gas market*

RAE launched a public consultation for the compensation methodology of gas units that cover charges arising in the gas market (i.e. Charges Daily Scheduling and deviations charges from the Reserved Transmission Capacity Gas Receipt) due to issued distribution orders that vary the operating level of incremental points compared to the level resulting from the resolution of the DAS. RAE decided to amend Article 116 of the Transmission Grid Code for Electricity (Decision

467/2015) to consider additional commands that result in decreased production. The decision on the detailed compensation methodology was taken in 2016 because there was a need to investigate further the alternatives expressed in the public consultation.

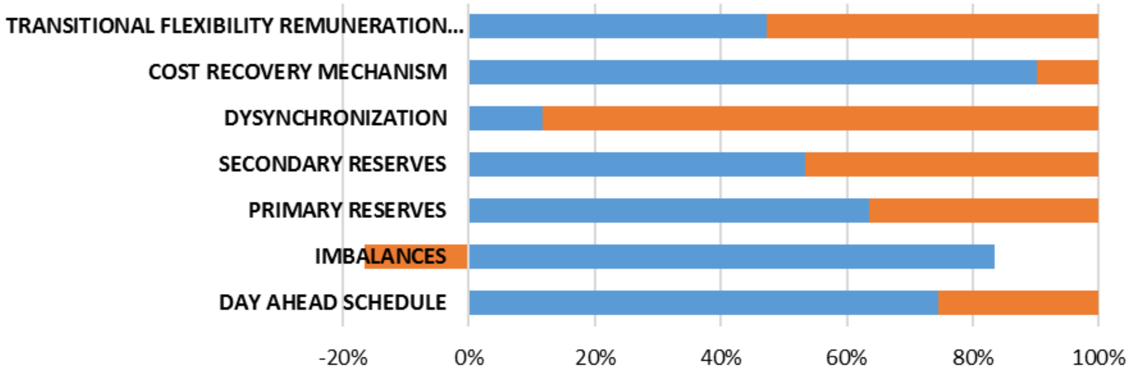
3.2.1.4 Market Settlement

2016 was the sixth year of the implementation of the market design that allowed for the settlement of imbalances, and the third year of the reform package for the wholesale market, as described above. The remuneration through the day-ahead market represented 87% of generators' cash flows, as compared to 95% in 2015, to 77% in 2014 and 63% in 2013. More specifically, the generators' annual revenues from the day-ahead market amounted to €1,44 billion in 2016 as compared to €1,77 billion in 2015, while ex-post settlements and supplementary mechanisms amounted to € 232 million. Hence, the turnover of the wholesale market reached €1,68billion in 2016 as compared to €1,86billion in 2015, €2.7 billion in 2014 and €3.02 billion in 2013.

The Cost Recovery Mechanism was zero in 2015 and when it was abolished on 30.6.2014, amounted to only €57 mil. in 2014 (essentially in the first half of the year), compared to €556 mil. in 2013. In 2016, however the reintroduction of the cost recovery mechanism amounted to 32 million. Primary and secondary reserve payments amounted to €665.000 and "desynchronization" payments amounted to €54,5 million.

For PPC, the day-ahead market reflected almost 90% of its income as a producer (86% in 2015, 79% in 2014), while for the Independent Power Producers (IPPs), the corresponding percentage was 76% in 2016 (68% in 2015, and 44% in 2014). Hence, ex-post settlement amounts and supplementary mechanisms are still crucial for the viability of the new independent plants in 2016, contributing another 24% to their cash flows. The differentiation regarding the allocation of cash-flows across PPC and IPPs is evident, reflecting various structural asymmetries, which although have blunted after the reforms of Decisions 338/2013 and 339/2013, are still present. Perhaps the most crucial factor is that, settlement mechanisms (imbalances, "desynchronization", primary and secondary reserves) translate into cash flows for IPPs and that PPC remained as the dominant supplier in 2016.

FIGURE 4 : Generators' Revenue by Source (in mil. € and in %)



	DAY AHEAD SCHEDULE	IMBALANCES	PRIMARY RESERVES	SECONDARY RESERVES	DYSYNCHRONIZATION	COST RECOVERY MECHANISM	TRANSITIONAL FLEXIBILITY REMUNERATION MECHANISM FRM
PPC	1.086,21	21,83	0,0038	0,35	6,44	28,08	53,20
IPPs	369,61	-4,34	0,0022	0,31	48,16	3,08	59,37

Although no significant changes in the rules of the wholesale market (a mandatory pool) were introduced during 2016, the supplementary mechanisms (Cost Recovery Mechanism and the Transitional Capacity Adequacy Mechanism) which exerted a substantial impact on market outcomes, had already revised in crucial aspects in 2015, to yield more competitive outcomes taking the form of a Transitional Flexibility Remuneration Mechanism (FRM). Thus, the European Commission approved finally a Transitional Flexibility Remuneration Mechanism (FRM) for one more year as a transitional measure to the target model C (2016)1791 final/31.03.2016.

With the law 4389/2016, the approved by the European Commission Transitional Capacity Mechanism (FRM) was transposed into the Greek legislation.

According to the Law 4389/2016 and the commitments of the national authorities to the European Commission for the transitional character of the FRM in the domestic wholesale market, RAE in cooperation with ADMIE SA had to proceed to:

i) amendments to the network code
j) amendments to the market clearing procedures
k) establish a list of eligible generation units for the participation in the mechanism
l) establish a methodology of imposed sanctions.

In this context, considering the connection of the adoption of this mechanism with the commitments by Greece to reform various aspects of the wholesale electricity market, RAE took the initiative to set up an expert group, consisting of members of the Authority, the System Operator and the Market Operator, which refined the relevant commitments and constructed a roadmap for their implementation. These commitments will be implemented, considering studies' results from about the impact assessment in preparation of the following measures in the Greek market:

- Increase the maximum bid price limit of DAS.
- Require Statements of availability of hydroelectric power plants.
- Increase limit secondary backup offers.
- Introduce Pricing Methodology hydro.
- Compensate tertiary reserves
- Re-evaluate the framework of charges for electricity exports to charges of the Uplift Accounts. (settlement accounts from market clearing – i.e. imbalance settlements in the wholesale market of the day of the system operation).

Furthermore, RAE fulfilled its commitment to reassess the framework of charges for electricity export with its Decision 471/2015 according to which, from 01/01/2016 exports are exempt from the charges of the Uplift Account UA-2, UA-5 and UA-6, because these charges are not directly related to an inherent and integral part of the production costs themselves for exported electricity nor concern financial costs such activity is causing or likely to cause, by direct causation, the Transmission System Operator.

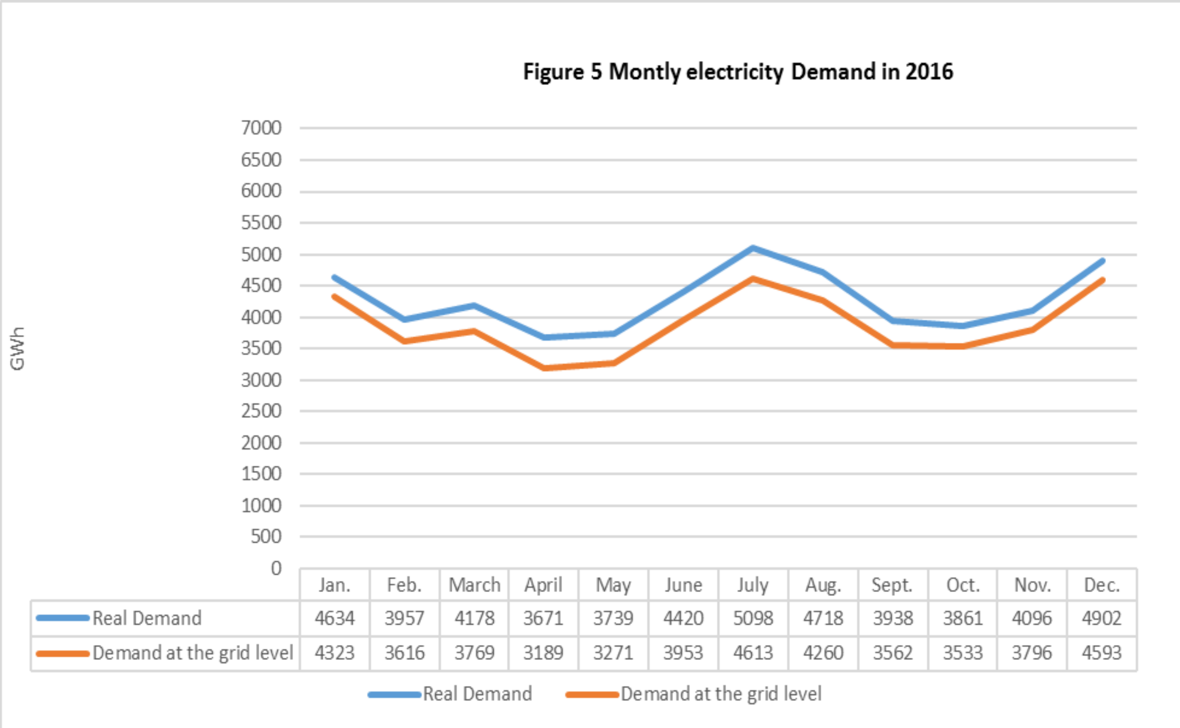
For the permanent Remuneration Mechanism, whose implementation is the responsibility of Greece in accordance with the provisions of paragraph 4.3 of Section III of Article 3 of Law 4336/2015 (Government Gazette 94 / 09.14.2015), RAE in 2015 set up a relevant Working Group. RAE in cooperation with the ADMIE analyzed the options for the design of the new mechanism. The objective was agreed on the basic principles of the mechanism and was released for public consultation and pre-notification to the European Commission (DG D / Directorate of Competition) to be implemented within the year 2017.

3.2.1.5 Market Size with respect to Quantity.

The day-ahead market yields the reference price for the industry, as it constitutes the major component on which generators' cash-flows are based. Due to the mandatory physical trading in this market, the traded volume of electricity is equal to the total production (the DAS outcome) plus the net interconnection balance. This value was equal to 51,2TWh in 2016 (51,3TWh in 2015), reflecting a marginal decrease of -0,28% relative to 2015.

Figure 5 displays the demand fluctuations at the aggregated monthly level, both based on grid metering and, also, by considering the PVs connected to the distribution network (real demand level). A forward market with a future delivery products has not been developed yet, while the over the counter trading (OTC) has not been activated either.

Table 21: Monthly electricity Demand													
	Jan	**Feb**	**March**	**April**	**May**	**June**	**July**	**Aug.**	**Sept.**	**Oct**	**Nov.**	**Dec**	Total
Real Consumption (GWh), in 2016	4634	3957	4178	3671	3739	4420	5098	4718	3938	3861	4096	4902	51212
Consumption at the Grid level (GWh), in 2016	4323	3616	3769	3189	3271	3953	4613	4260	3562	3533	3796	4593	46478
Real Consumption in 2015 (GWh)	4810	4321	4496	3800	3853	3971	5032	4700	4085	3816	3876	4595	51355
Difference between real consumptions in 2015, 2016 (GWh)	-176	-364	-318	-129	-114	449	66	18	-147	45	220	307	-143
% change in real consumption 2016-2015	-3,66	-8,42	-7,07	-3,39	-2,96	11,31	1,31	0,38	-3,60	1,18	5,68	6,68	-0,28



The installed capacity at the end of the year, as well as the annual production shares across fuels and imports, are presented in Section 3.2.1.2

3.2.1.6 Monitoring market shares

Regarding the market structure, PPC retained in 2016 its dominant position. The previous two years, on the generation side, reflecting the addition of a new hydro station of 155 MW in 2014 and CCGT plans in 2015 (845MW), PPC's market (generation) share increased, reaching a level of 88% (excluding RES, in terms of conventional technologies (thermal and large hydro) in the interconnected system in 2015. However, the reduction of PPC's lignite generation units and as a result the reduction of PPC's total installed lignite generation capacity from 4.456MW to 3912MW in 2016, PPC's market generation capacity share was 75%. In respect to the installed capacity the incumbent's market share was 79% in 2016 as compares to 81,7% in 2015. In terms of conventional technologies (thermal and large hydro) in the interconnected system plus RES, the incumbent's (PPC's) market generation capacity share was 56,7% if renewable generation capacity is also considered. Additionally, the incumbent's market generation share was 58% if renewable generation is also considered. It should be emphasized that in the generation sector, a less concentrated structure has been emerging gradually since 2010, when two new IPP units start to operate.

This change was reinforced in 2011, with the addition of two more IPP plants, and subsequently, in 2012, with the addition of a fifth plant, all being similar in terms of capacity and technology (gas CCGT of about 400 MW capacity each). In terms of thermal capacity, this direction of market evolution seems to converge towards an equilibrium point. More specifically, all private plants have now been completed, while, in terms of the incumbent's new capacity investments, a new CCGT plant (Aliveri V, 417 MW) entered the market in March 2013 and the last on-going CCGT project (Megalopoli V) is expected to become operational in the next few years. Although investment has reached a saturation point, given the suppressed demand levels, the market structure could change, however, if: a) plant divestments, included as a prerequisite in the Greek MoU on Specific Economic Policy. Conditionality, or b) alternative measures on PPC's capacity allocation are implemented by the government in the coming years. The formation of a new vertical company, consisting of a portfolio of PPC's assets, was reviewed in 2016. Apart from conventional generation, changes in market structure were enhanced by an almost "explosive" penetration of renewables, in which PPC's share remains minor; this tendency was restrained in 2014 and 2015, after the imposition of "corrective" measures by the government in terms of lower feed-in-tariffs, taxes on revenues, and time limits in the completion of renewable investments. Summarizing, eight (8) IPP gas plants are currently active in the wholesale market. Their ownership structure is presented below:

- Enthess (389 MW) and Thisvi (410 MW), both CCGT plants, are owned by Elpedison S.A.
- Heron II (422 MW, CCGT) and Heron I (147.5 MW, OCGT) are owned by Heron
- Thermoelectric S.A. (GEK Terna - Gdf Suez).
- Protergia (433 MW, CCGT), Korinthos Power (434 MW, CCGT) and Alouminion (334 MW, large-scale CHP) are owned by the Mytilinaios Group.
- A cogeneration unit of 2 MW net capacity, with very limited activity in 2013, is owned by the Motor Oil refinery.

Moreover, as stated by the TSO in its most recent Ten-Year Network Development Plan (2016-2025), two (2) additional thermal units, of 851 MW total capacity, had also applied for connection by December 2013. This capacity includes the incumbent's new CCGT unit Megalopoli V (811MW), the materialization progress of which is linked to the expansion of the gas network in the Peloponnese central region. The above capacity of 851 MW does not include, however, the new lignite unit Ptolemaida V (660 MW), for which private investor involvement, along with PPC, has been discussed. In addition, the hydro unit Ilarion (143 MW), on the Aliakmonas river, started commissioning in February 2014, while six (6) other hydro units (two of which are pumping stations of 231 and 403 MW), of total capacity 940 MW, have already been licensed, but not all of them have applied for connection yet. Following the decommissioning of 250 MW of obsolete lignite units (Megalopoli I and II) in 2012, Ptolemaida II (116 MW) entered a cold reserve status in October 2013. Finally, a fire in November 2014 set off Ptolemaida Units 3 and 4.

In terms of volume, the incumbent's share in 2016 in the interconnected system amounted to almost 76% of the domestic production (excluding RES), while independent gas producers achieved a 24% share. The net installed capacity and the produced volumes per fuel and producer in 2016 are depicted in the following Figures 6,7 and 8.

Figue 6 Installed Electricity Generation (net) Capacity in 2016 (MW), per producer and fuel (%), excluding IPPs' RES

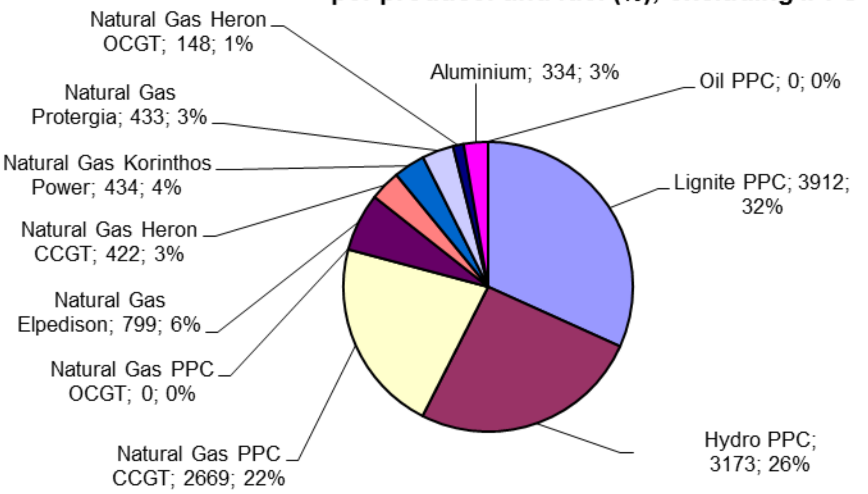
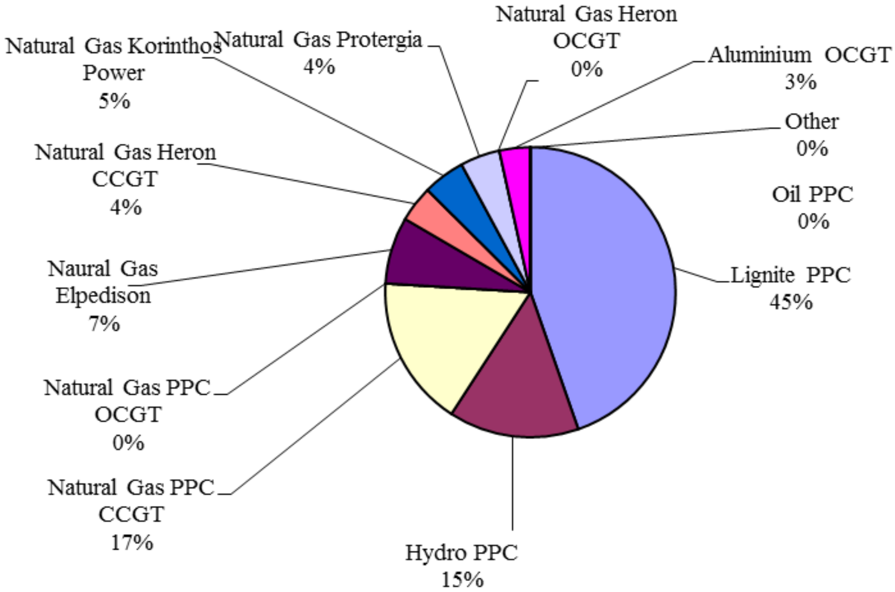


Figure 7 Electricity Generation in 2016 per producer and fuel (%), excluding IPPs' RES



The HHI index for the wholesale market in 2016, a measure of market concentration, attained the value of 5999 in terms of volume production and 6423 in terms of installed capacity; these values are to be compared with 7820 and 6804, respectively, in 2014. We should underline however; the calculation of these indicators does not consider RES generation and RES installed capacity. The main argument is that RES do not participate in the market under the implemented rules of feed in tariff (FiT) and of access (dispatch) priority, in 2016. Market concentration is decreasing further if we consider the net imports volume, in 2016.

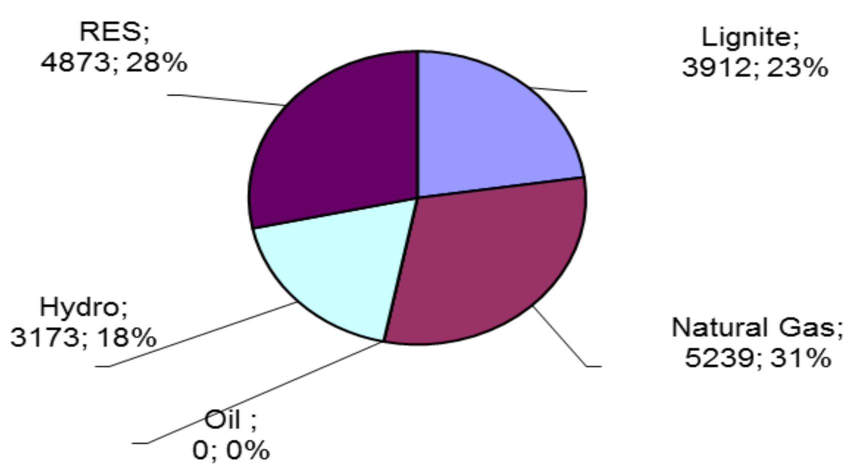
In 2016, the decrease in terms of volume of the production by the PPC, is the result of the closure of old PPC lignite units and the delay of completion and operation of new lignite units. Of course, it should not be overlooked that a long way has been travelled since 2009, when the HHI was close to the upper limit of 10.000. The market is evolving in a more competitive direction, the basic structural constraint being the lack of fuel diversification for IPPs, as well as the lack of physical hedge for them. However, if RES were participating into the market, based on the generation volumes produced in 2016, HHI index for the wholesale market would be no more than 4000.

Table 22. Share in produced volume per Group in 2016 (%)*	
PPC	75,96%
Elpedison	7,46%
prot+aloum+kp	12,54%
Heron	4,04%
Note: * RES generation from the Independent power generators is not included	
Year	**HHI index (production)**
2016	**5999**
2015	7820
2014	8091
2013	6553

Table 16. Share in installed capacity (MW) by Group (%) in 2016.	
PPC	79,15%
Elpedison	6,49%
prot+aloum+kp	9,74%
Heron	4,63%

Table 17 Market Share Installed Capacity & HHI Index, 2016	
2016	**PPC**
PPC's Share in installed generation capacity (except RES)	79,1%
PPC's Share in installed generation capacity (incl.RES)	56,7%
Year	**HHI index installed capacity.**
2016	**6423**
2015	6804
2014	6624
2013	6597

Figure 9 Installed Generation Capacity by fuel, in 2016 (MW)



3.2.1.7 Price Monitoring

The current market design involves two distinct settlement processes:

- The settlement of the day-ahead market, in which generators' payments (suppliers' charges) are calculated, based on the System Marginal Prices (SMP) and the plant schedules derived from the day-ahead dispatch (load declarations submitted).

- The settlement of imbalances, in which deviations from day-ahead schedules are charged or compensated, based on the Marginal Imbalance Price (IMP), depending on whether they reflect the TSO dispatch orders (the real operated time) or plant-specific reasons

Small variation between the System Marginal Price and the Imbalance (Diverted) Marginal Price (real - grid operated price) illustrates better correlation of the offers of the generation units (plants' schedules) and demand in the day ahead market with the dispatch orders (the real operated time of the grid see Figure 10).

The average System Marginal Price (SMP) in 2016 amounted to 42,85 €/MWh with a standard deviation +- 4,65 €/MWh (10,8%) recording a noticeable decrease (-17,5%) compared with the previous year (SMP; 51.93 €/MWh in 2015). The SMP had already recorded a significant reduction in 2015 (-9,8%) compared to the previous year 57.56 €/MWh in 2014. Current system marginal (yearly average) price (SMP) has returned to the level of the average SMP in 2013 (41.47 €/MWh). In addition, the average annual difference between the System Marginal price and the Imbalance Marginal (operating) Price was 2,78 €/MWh, in 2016 (see Figure 10).

The difference between the Revenue of the Independent Power Producers (IPPs) from the system marginal price (SMP) granted by the day ahead market and the price granted by the market (and the grid) physical operation (on real time) increased significantly, in 2016. The SMP of the day ahead market was 42,85 €/MWh, while the calculated average price of the total Revenue of IPPs (which equals to the Revenue from the day Ahead market plus the Revenue of the IPPs received from the operation of the other supplementary mechanisms such as the transitory reserve capacity mechanism, the variable cost recovery mechanism, was 50,60 €/MWh (see Figure 4: Generators' Revenue sources). We recall that the difference of these two prices was only 4,12€/MWh (51,93€/MWh and 56,05 €/MWh respectively) in 2015. In 2014 the difference between these two prices was 20€/MWh (57,56 €/MWh και 79,5 €/MWh respectively). Clearly, the operation of the transitory capacity Reserves mechanism has increased the difference between the two prices.

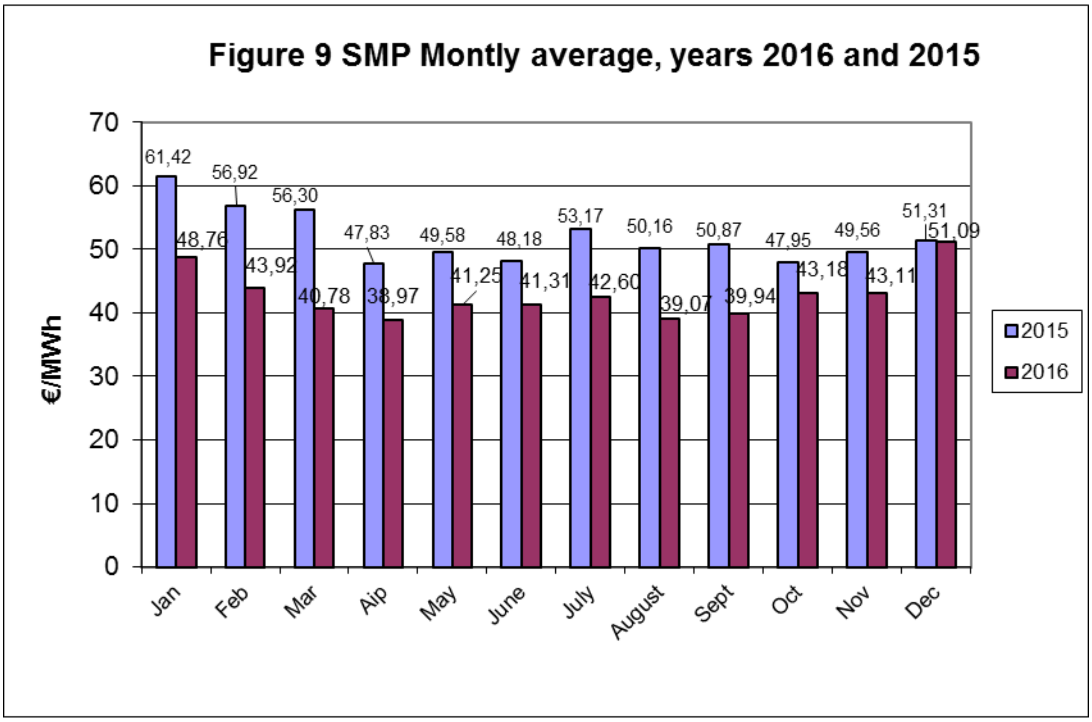
The operating SMP price (usually called as the Diverted Marginal price/**OTA**) represents the real value of the operation of the electricity market and this price was 45,62€/MWh, in 2016. (SMP 42,85 €/MWh). The diverted Marginal Price (OTA) represents the outcome of the calculated real quantity of the generators loaded into the grid in the operating day excluding any kind of estimations, forecasts of the day ahead market about the RES generation availability, estimated inflows (imports) and available units for operation. In this respect, the System Marginal Price of the day ahead market is a kind of virtual price or a virtual SMP. In real time quantities by generation units that are not available in the system but had participated in the day ahead market must be offset by other generation units. For instance, the lignite generation units' load deficit must be offset by the load from the hydro or natural gas units.

Volatility between the two prices; SMP and the diverted Marginal Price OTA decreased significantly in 2016 (see Figure 10), one of the reasons is the better operation of the market by the Market Operator, including an efficient daily integration of RES into the system (better estimation of the generated electricity quantities by RES). However, we should not underestimate the fact that another reason for the lower volatility of prices and especially the lower volatility between the SMP price and the diverted Marginal price (OTA) is the operation of the transitory capacity reserve mechanism, in 2016.

Focusing on monthly fluctuations, which are depicted in Figure 9, it is noteworthy that the average SMP showed quite normal behavior in 2016 ranging between 38,9 € / MWh in April and 51,09 € / MWh in December. The maximum monthly level of SMP was primarily due to weather conditions, as in December 2016 and January 2017 (especially the first ten days) which was characterized by extreme snow and frost conditions. In general, the change of SMP levels, ranging monthly between -10% and 19%. Noticeable are; the zero-monthly change of SMP in June and in November and SMP's greater monthly variation 19%, in December. Overall, the price of SMP recorded a downward trend, in 2016.

In 2016, the monthly fluctuations of SMP reflect significantly the seasonality of demand and various factors. At this point it should be noted that the variation of RES production had an effect like that of 2014 and 2015, and the total annual participation in the day ahead scheduled market (DAS) showed a slight increase of 6.43%, reaching 23,5%. RES had sharply increased, their participation in the DAS. The downward trend of SMP prices recorded the first quarter of 2016. In April, the market recorded the lowest monthly average SMP 38,97 € / MWh. The downward trend stopped in July but in August the downward trend carry on due to the highest participation of RES in the market (Summer). Finally, the highest monthly level of SMP that recorded in December 2016 (51,09 € / MWh) followed a downward trend in prices in the first months of 2017. The increase in prices in December, was the result of a) supply pressures as many domestic lignite units were under the status of repair and maintenance, b) the production deficit caused by a lack of imports, and c) the sluggish production of RES and the limited production of hydroelectric units due to the extreme weather conditions (snow and fog).

In 2016, the variability of the hourly levels of SMP, as reflected in the standard deviation showed a significant decrease, recording average daily 4,63 € / MWh compared with 7,28 € / MWh, 11,14 € / MWh and 13,17 € / MWh in the years 2015, 2014 and 2013, respectively. This reflects the more homogeneous variation of prices around the levels at which stood at 2016 (see Figure 10). These characteristics are reflected in the duration of SMP curve. It is indicative that the SMP exceeded 80 € / MWh for only 0,2% meaning annual total; 19 hours of the total hour's distribution compared with 1% of hours in 2015, 8% of hours in 2014 and 7% of the hours in 2013. Out of these 19 hours, 16 hours with the recorded prices over 80€ / MWh took place in December 2016. In addition, the hours during which the SMP received greater than 55 € / MWh have decreased significantly (Figure 11). Generally, the SMP was determined mainly from natural gas units (48% of the total hours of the year) and then by the lignite plans (33%), while less frequently than imports (11%), exports (6%) or hydro (2%). This result indicates that the Bid from hydropower plants, the existing regulatory framework, creates a strong, almost rigid, overhead power band, the availability of which appears nearly uniform without being directly linked to the levels and inputs reservoirs. This zone compresses with an almost uniform the SMP, while required arise multiple and specific market conditions for the bypass.



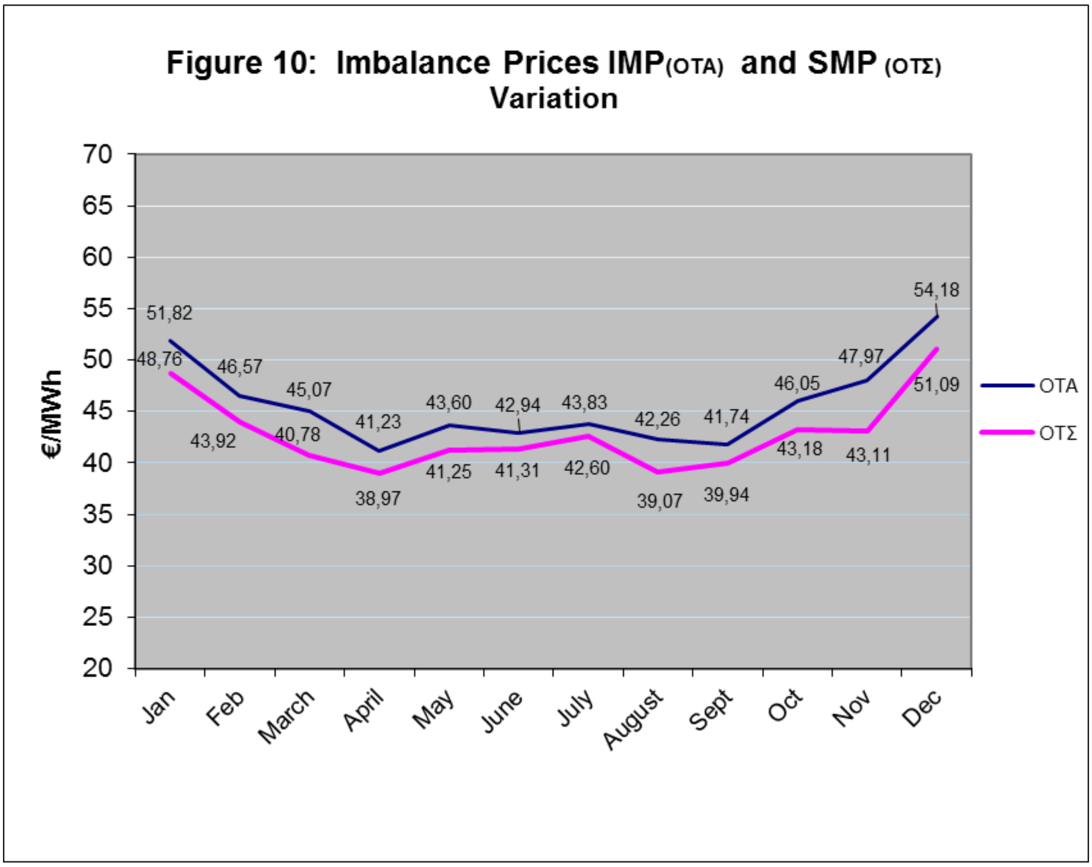


Figure 10: Imbalance Prices IMP(OTA) and SMP (OTΣ) Variation
€/MWh
70
65
60
55
50
45
40
35
30
25
20
51,82
48,76
46,57
43,92
45,07
40,78
41,23
38,97
43,60
41,25
42,94
41,31
43,83
42,60
42,26
39,07
41,74
39,94
46,05
43,18
47,97
43,11
54,18
51,09
Jan
Feb
March
April
May
June
July
August
Sept
Oct
Nov
Dec
OTA
OTΣ

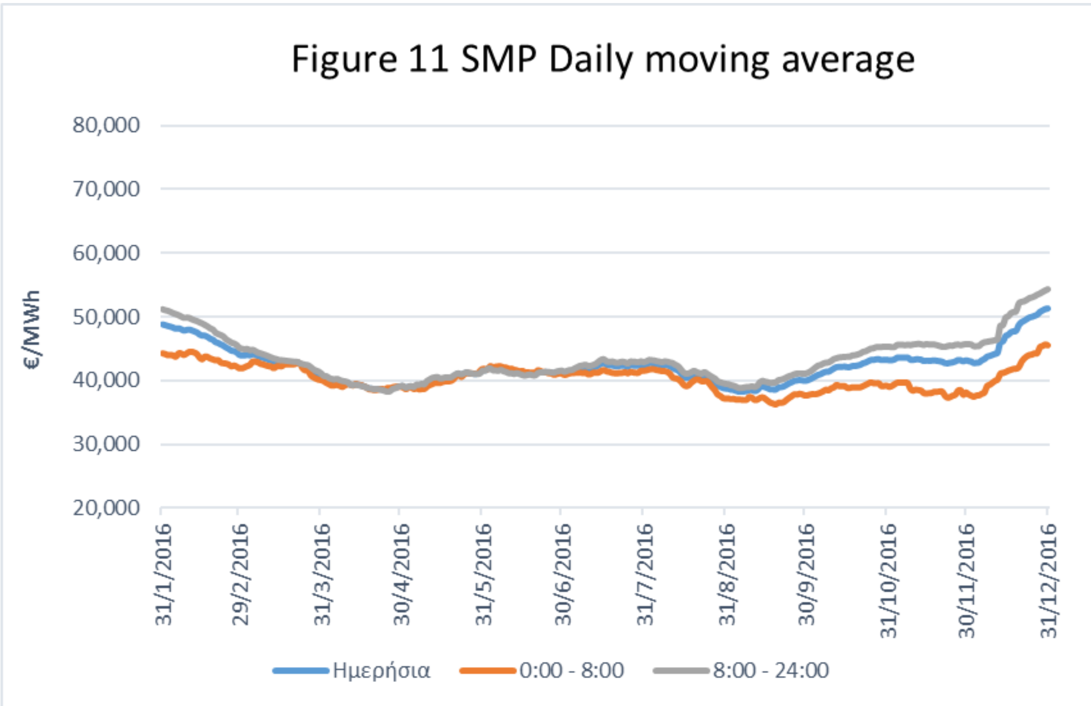
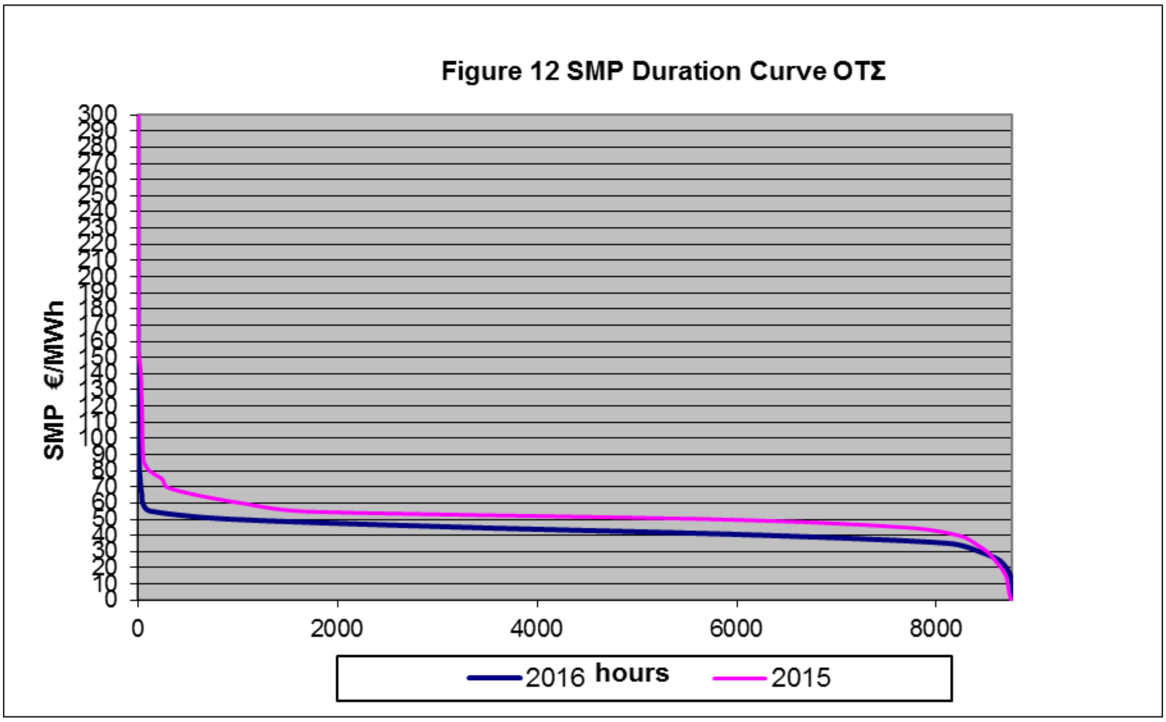


Figure 11 SMP Daily moving average
€/MWh
80,000
70,000
60,000
50,000
40,000
30,000
20,000
31/1/2016
29/2/2016
31/3/2016
30/4/2016
31/5/2016
30/6/2016
31/7/2016
31/8/2016
30/9/2016
31/10/2016
30/11/2016
31/12/2016
Ημερήσια
0:00 - 8:00
8:00 - 24:00

Regarding extreme hourly rates, the SMP did not touch the ceiling of 300 € / MWh while it touched and overthrown the old ceiling of 150 € / MWh in just 9 hours of distribution, all in December, as there were no extreme conditions which marked, even temporarily, potential power deficit. Such cases were observed in previous years, for thirty-nine (39) hours allocation in 2012 because of a supply crisis in natural gas in February, and for fourteen (14) hours allocation in June 2011, due to the strike GENOP PIO, but not in 2013. 10 hours observed during 2015 were essentially the result of bad weather, which led to an increase in demand, coupled with the reduced availability of units, because maintenance periods, damage or reduced quality fuel. Examples include the case of February 14, the day on which the 4456 MW net installed power of lignite plants in the system was only available to those 2373 MW, i.e. 53%. Of the 2083 MW, which were not available, 32% was due to injury, 27% in scheduled maintenance and 34% to non-availability or poor quality lignite. On 12th December 2016, and for 3 hours the SMP reached the price 299 € / MWh, essentially the result of bad weather.

It is noteworthy that the frequency of zero values increased in 2016 to 10 hours comparing to just 5 hours in 2015, 31 hours in 2014 and 674 hours in 2013. Note that zeros occur predominantly at the times demand, in which compulsory injections (hydropower, renewable energy production, technical minimum thermal units, imports) exceed consumption. In these cases, is cut in imports, due to the structure of the DAS solving constraints, and, therefore, the SMP is determined by input supply, which had been zero-rated. Limiting zero values partly reflecting a marked decline in domestic production, resulting in the technical minimum of conventional units to enter and cut imports to a lesser extent. 60% of these zero values corresponding to 6 hours of distribution were observed in the months of March and November, and whenever there were particularly high imports in the order of 795,2 to 1.643,00 MWh, covering up to one third of demand for those hours (namely coverage ranged from 18.20% to 32.32% for free). Taking account of the technical requirements of the algorithm, such as function modules to provide redundancy, inability quenching units before the expiration of the minimum running time, etc., the fact that there were no heavy rains and therefore mandatory injections hydropower for specific times, probably contributed to reducing the phenomenon.



3.2.1.8 Monitoring of transparency

Following the transparency requirements posed by the Codes, the TSO and the Market Operator publish daily detailed market data related to the day-ahead market and the imbalance settlement mechanism, respectively. The published data are not confined to hourly levels of prices and key fundamentals. Both ADMIE and LAGIE upload Excel files with clear quantitative market inputs (except generators' offers and suppliers' bids which constitute confidential data), as well as all outputs relevant to the cost-minimization algorithms that each operator solves. In this context, ADMIE publishes daily forecasts for various market inputs, including demand and renewable production (across technology categories), plant availability declarations, mandatory water declarations submitted by PPC on a weekly basis (forecasts or metered data), reserve requirements, long-term interconnection capacity rights and NTC values. Apart from market inputs, the TSO also publishes the real-time plant schedule (DS), solved with the TSO's demand forecast (instead of load declarations) and with network constraints more explicitly incorporated. This schedule is obtained initially on a day-ahead basis and, subsequently, gets updated within the day. In addition, ADMIE publishes the outcomes of the ex-post market clearing obtained with metered data (instead of predicted values) for the various inputs. LAGIE publishes the values of inputs inserted to the DAS algorithm and all the resulting market outcomes, including prices and plant schedules for the day-ahead market, along with primary and secondary reserves (which are co-optimized), as well as tertiary reserve quantities. Monthly reports, which had been developed before the adaptation of the ITO model, continued to be published by ADMIE, focusing on production allocation, fuel market shares and demand segmentation, but not on prices.

With the objective to increase transparency by further clarifying market parameters and market conduct, RAE requested from LAGIE and ADMIE to develop monthly reports, displaying outcomes of the day-ahead market and ex-post settlements, respectively, to comply with the requirements of the new Codes. The structure of these reports was designed in collaboration with RAE. LAGIE issued its first market report for the month November 2012, which was subject to revisions and additions, before its standardized format was finally approved by RAE in February 2013. This report is uploaded on LAGIE's website, monthly, from November 2012 onwards. ADMIE has been drafting and publishing an energy report, which is focused on the dynamics and allocation of energy quantities. RAE has also requested the addition of references to the cash settlements in which the TSO is involved, so that transparency is enhanced further.

3.2.1.9 REMIT (EU Regulation 1227/2011)

Furthermore, as the Greek NRA responsible for the application of REMIT Regulation in the energy wholesale markets in the country, we have worked with the Agency for the Cooperation of Energy Regulators (ACER) and with other European NRAs towards a common understanding on the administration and methodology to be followed regarding the identification, investigation and sanctioning of REMIT breaches. In parallel, RAE worked on capacity building among staff, especially about market participants' registration process and data collection. More specifically, under the EU regulation 1227/2011 on wholesale markets integrity and transparency, market participants entering transactions, which are required to be reported to the Agency shall register with the relevant National Regulatory Authority (NRA). The requirement to register applies to any person, legal or natural.

Per the EU Regulation 1348/2014 of the implementing acts of articles 8 par 2 and 6 on data reporting of the Regulation 1227/2011, NRAs shall establish national registers of market participants. This means that each NRA had to establish a registration system no later than three months after the adoption of the European Commission's implementing acts, i.e. counting from 17 December 2014, to enable market participants to provide their registration information to that NRA. NRAs can, if they wish, open the registration process to market participants also earlier. NRAs are free to use whatever system they consider most appropriate for their market.

The Agency developed the Centralized European Register for Wholesale Energy Market participants (CEREMP) to establish the European register of market participants in natural gas and electricity markets. This system is also available to NRAs as a means for registering market participants in their own Member State. RAE has chosen the option to use CEREMP platform and not to develop its own registration system for cost limitation reasons. Accordingly, RAE signed a Service Legal Agreement, SLA with ACER to use CEREMP platform, in 2014. Additionally, RAE signed with ACER a Memorandum of Understanding on the sharing of information under REMIT. Finally, RAE completed successfully the registration of all market participants in electricity and natural gas markets, in September 2015, and all the requirements for the reporting of market participants' standard contracts transactions, on 7th October 2015.

The reporting of market participants' transactions take place through the Registered Reporting Mechanisms (RRM) which have been certified by RAE. In 2015 RAE, had already recognized as

Registered Reporting Mechanisms: The Market operator of the electricity market (LAGIE S.A.), the operator of the electricity transmission system (ADMIE).

Furthermore, RAE followed all the required steps for the successful completion of the process for the reporting by the market participants, any other transactions that do not take place in organized markets (over the count transactions), on 7th April 2016.

3.2.1.10 Monitoring of effectiveness of market opening and competition

The challenging issues that continued to arise in the domestic electricity market throughout 2016 emphasized that, apart from plant portfolio diversification, a crucial element for a more competitive market evolution, with self-sustained financial outcomes and less dependency on supplementary mechanisms, would be the emergence of open market oriented reforms.

RAE assessed market restructuring options, so that the local market becomes compatible within the Target Model framework (the market coupling with Italy).

Electricity Target Model : Regarding the harmonization of the wholesale market with the EU Target Model, RAE, in close cooperation with the Independent Transmission System Operator, ADMIE SA and the Market Operator, LAGIE SA, commissioned an international Consultant to develop the High Level Market Design for Reorganizing the Wholesale Electricity Market in Greece with a view to adopting to the requirements of the EU Target Model, as these are set through the corresponding ENTSO-E Network Codes. Under the proposed solution, the operation of a forward market, a day-ahead market and an intraday market are foreseen. An Integrated Scheduling Process is also proposed accompanied by a Real Time Balancing Mechanism with a view to enabling the TSO to procure operating reserves and balance the system in the most cost-efficient way. In 2016, RAE provided and decided on a document presenting the regulatory guidelines, per which all necessary actions will be instigated immediately for the technical implementation of the Target Model (i.e. the establishment of: an intraday market, a forward market and a balancing market).

Nominated Electricity Market Operator (NEMO): Per the European network code on (transmission) Capacity allocation and Congestion Management (CACM), the Nominated Electricity Market Operator is responsible for the market coupling of the day ahead electricity market and the intraday market. The Greek law 4001/2011 provides that for the Greek Electricity Market there can be only one entity that is responsible for the day ahead electricity market and the intraday market, which is the Market Operator (LAGIE S.A). Therefore, with the ΑΠΕΗΛ/Γ/Φ1/οικ.184866/11.12.2015 Ministerial Decision, which was notified to the European Commission, and taking into consideration to the Opinion 4/2015 of RAE, LAGIE S.A. was designated as the Nominated Electricity Market Operator for a period of four years.

3.2.1.11 NOME Auctions (Nouvelle Organization du Marché de l' Electricité)

First Auctions of wholesale electricity products by the Public Power Electricity Corporation (PPC), the incumbent, to reduce its market share in the wholesale and retail market took place, in October 2016. Auctions' "philosophy and organization" are based on the French electricity market model "Nouvelle Organization du Marché de l' Electricité" (NOME Law), which was adopted in the French electricity market, in 2010. More specific, first tendering of PPC's offering of its lignite electricity generation to the Independent private producers and suppliers has already taken place. – that is one of the actions/measures taken by the government for the limitation of PPC's share in the wholesale and the retail markets to less than 50% (up to the year 2020).

Based on law 4336/2015 which detailed the Greek Government's responsibility to reduce PPC's market share by 25% and fall below 50% by 2020, while system marginal prices will cover the cost of production, RAE submitted to the Ministry of Energy and to the Central Unit for State Aid, a proposal for the creation of a forward market based on NOME type auctions: an auction process with a regulatory-defined starting price that reflects the full cost of efficient lignite production. The basic concept for the product design, as introduced in RAE's latest document, provides the opportunity for the whole spectrum of consumers to be supplied by alternative supplies as an alternative to PPC. The starting point is designed to be the current level of end-prices for all customer categories. The quantity to be auctioned concerns 1200 MW of baseload lignite and hydro generation. The auctions are organized on an annual and quarterly basis for each year, for 4 years. The proposed auctions are transitional and designed so that by 2017 (EU Target Model will be in place), there will be similar products traded on market basis that will provide the opportunities for suppliers and generators to manage in a long-term basis their positions.

In September 2015, a joint working group was formed by a Ministerial Decision (39229/16.09.2015) with the purpose of organizing and managing the implementation of NOME type auctions. Thus, RAE issued the code of auctions and exchanges of future electricity products in September 2016 (RAE decision ref no 329/23.09.2016). The initial price for the auction (the reference price) was decided with a Ministerial Decision in September 2016 and the first auction was organized successfully, on 25th October 2016. The Decision 353/2016 of RAE, notified and conformed the level of the quantity available for auction (Lignite and Hydro) which was determined at 460MW and the reference price (auction price) at 37,37 €/MWh.

3.2.2 Retail Market

3.2.2.1 Description of the retail market

The overall electricity consumption in the Interconnected System in 2016 recorded a small decrease of 0,4% in comparison to 2015 (estimated). This decrease is the result of years of continuing economic recession, which has caused an overall decline of about 6% in the total electricity demand of the Interconnected System, over the 5-year period of 2011 to 2016. This decreasing trend in the overall electricity demand is depicted at the following Table 23.

Table 23. Electricity consumption at the interconnected system (GWh)

	Year	Large Industrial Customers	Household Customers	Small Industrial & Commercial Customers)	Other (e.g. agriculture, public, traction)	TOTAL (GWh))
LV	2011	-	16.116	10.535	3.526	**30.177**
	2012	-	16.714	10.123	3.734	**30.571**
	2013	-	15.973	9.560	3.640	**29.173**
	2014	-	15.569	9.523	3.735	**28.827**
	2015*	-	15.817	9.245	3.277	**28.339**
	2016		15.048	9.192	3.385	**27.625**
MV	2011	-	-	9.125	1.397	**10.522**
	2012	-	-	8.471	1.513	**9.984**
	2013	-	-	8.904	1.487	**10.391**
	2014	-	-	8.179	1.477	**9.656**
	2015*	-	-	8.351	1.473	**9.824**
	2016	-	-	8.643	1.478	**10.121**
HV	2011	6.613	-	-	1.536	**8.149**
	2012	6.507	-	-	1.361	**7.868**
	2013	6.599	-	-	1.168	**7.767**
	2014	6.702	-	-	1.314	**8.016**
	2015	6.805	-	-	1.150	**7.955**
	2016	7.062	-	-	1.115	**8.177**
Total	2011	6.613	16.116	19.660	6.459	**48.848**
	2012	6.507	16.714	18.594	6.608	**48.423**
	2013	6.599	15.973	18.464	6.295	**47.331**
	2014	6.702	15.569	17.702	6.526	**46.499**
	2015	6.805	15.817	17.596	6.526	**46.118**
	2016*	7.062	15.048	17.835	5978	**45.923**

In 2016, stability in the retail electricity market remained and no extraordinary events occurred, with only three new companies entering the market (Greek Post Offices S.A, Interbeton S.A. and OTE real estate S.A.). Overall, in 2016 there were no major events or developments that affected the representation of retail electricity consumers. At the end of 2016, ten (13) electricity suppliers were active in the retail market:

1. PPC S.A.
2. ELPEDISON ENERGY S.A.
3. WATT & VOLT S.A.
4. HERON THERMOELECTRIC S.A.
5. GREEK ENVIRONMENTAL & ENERGY NETWORK S.A.
6. VOLTERRA S.A.
7. PROTERGIA THERMOELECTRIC AGIOS NIKOLAOS S.A.
8. NRG TRADING HOUSE S.A.
9. TITAN S.A.
10. NOVAENERGY SA (previously known as NECO Trading S.A.)
11. Greek Post Offices S.A.
12. INTERBETON S.A.
13. OTE real estate S.A.

At the end of December 2016, the total numbers of licenses that RAE had approved were; 34 licenses of electricity supply and 57 licenses of electricity trading. But as we have already reported only 13 electricity suppliers are active (see above) in the domestic retail market. In 2016, RAE issued eight (8) Decisions for the approval of 8 electricity supply licenses, four (4) decisions for the similar number of electricity supply licenses' amendments (i.e. mainly amendments on ownership), one decision for a trading license's amendment and two decisions regarding the extension of the period of licenses.

3.2.2.2 Competition and market shares

In 2016, PPC SA remained by far the dominant supplier on the interconnected system, as it held almost the entire retail market (98% of the total number of customers and about 89% of total electricity supplied). Only a very small percentage (measured in terms of metering points) of the total LV and MV customers switched electricity supplier in 2016, a number slightly better than that of the year before, per the data provided by the DSO. Overall, in the domestic electricity market for the interconnected system, the total number of customers in 2016 was 6.616.305 and their total consumption was 37.746.718 MWh. It must be noted that in the non- interconnected system, PPC remains the sole supplier of electricity to all end consumers following an EU decision granting derogation from relevant articles of the Directive.

Another characteristic of the retail electricity market in 2016, was the continuous growth of consumers' liabilities against their electricity suppliers, reflecting the difficulties faced by consumers during the deep economic recession. The excessive charges mounted on electricity bills because of high (and multiple) taxes on energy, combined with the inclusion in the electricity bill of other taxes and fees not related to electricity (e.g. property tax, local authority tax, television fee, etc.), pushed a significant number of consumers to the edge of their budget constraints, thus resulting in either an ignorance to pay, or an actual inability to do so. Moreover, it must be noted that, although the special property tax was removed from electricity bills in 2014, this did not seem to improve the collection rates of the suppliers or the clearing of the previously accumulated bad debt.

Table 24. Suppliers' Retail Market shares by customers' category (type).

	Number of customers	PPC	WATT & VOLT	GREEN	INTER-BETON	NRG	ELPEDISON	NOVAERA	TITAN	VOLTERRA	OTE ESTATE	PROTERGIA	BIENEP	OTE	HPΩN	Greek Post Offices S. A
Household customers	5.158.597	5.066.503	12.685	1.616	1	830	32.295	5	0	1.129	0	34.471	1	0	9.061	0
Small industrial and Commercial LV customers	1.137.500	1.078.511	11.248	2.857	2	2.222	19.953	9	0	1.705	4.009	9.406	2	0	6.927	649
Other LV customers	309.918	309.849	0	0	0	2	2	0	0	39	1	2		0	23	0
Total LV customers	**6.606.015**	**6.454.863**	**23.933**	**4.473**	**3**	**3.054**	**52.250**	**14**	**0**	**2.873**	**4.010**	**43.879**	**3**	**0**	**16.011**	**649**
Commercial and Industrial MV customers	8.623	6.436	72	72	22	186	458	9	0	99	0	557	2	0	699	11
Other MV Customers	1.667	1.666	0	0	0	0	0	0	0	1	0	0	0	0	0	0
Total number of MV customers	**10.290**	**8.102**	**72**	**72**	**22**	**186**	**458**	**9**	**0**	**100**	**0**	**557**	**2**	**0**	**699**	**11**
Total number	**6.616.305**	**6.462.965**	**24.005**	**4.545**	**25**	**3.240**	**52.708**	**23**	**0**	**2.973**	**4.010**	**44.436**	**5**	**0**	**16.710**	**660**
Market share (%)		**97,68%**	**0,36%**	**0,07%**	**0,00%**	**0,05%**	**0,80%**	**0,00%**	**0,00%**	**0,04%**	**0,06%**	**0,67%**	**0,00%**	**0,00%**	**0,25%**	**0,01%**

Table 25. Consumption by consumers' category/type

	Consumption (MWh)	ΔEH	WATT & VOLT	GREEN	INTER-BETON	NRG	ELPEDISON	NOVAERA	TITAN	VOLTERRA	OTE ESTATE	PROTERGIA	BIENEP	OTE	Heron	Greek post offices
Household customers	15.047.984	14.841.135	28.438	5.302	0	2.593	110.445	4	0	3.042	0	42.223	0	0	14.803	0
Small Industrial and LV customers	9.192.244	7.901.503	140.667	74.127	19	70.989	359.524	207	0	52.668	22.256	274.109	1	953	290.385	4.836
Other LV customers	3.384.980	3.383.894	0	0	0	36	2	0	0	499	0	3	0	0	546	0
Total number of LV customers	**27.625.208**	**26.126.531**	**169.105**	**79.429**	**19**	**73.617**	**469.970**	**211**	**0**	**56.209**	**22.256**	**316.335**	**1**	**953**	**305.735**	**4.836**
Commercial and Industrial MV customers	8.643.061	6.023.099	29.446	78.399	10.361	196.474	533.421	7.052	6.629	147.613	0	750.178	1.329	123	854.182	4.756
Other MV customers	1.477.949	1.477.924	0	0	0	0	0	0	0	25	0	0	0	0	0	0
Total MV customers	**10.121.010**	**7.501.022**	**29.446**	**78.399**	**10.361**	**196.474**	**533.421**	**7.052**	**6.629**	**147.639**	**0**	**750.178**	**1.329**	**123**	**854.182**	**4.756**
Total number of customers' consumption	**37.746.218**	**33.627.554**	**198.550**	**157.829**	**10.380**	**270.091**	**1.003.392**	**7.263**	**6.629**	**203.848**	**22.256**	**1.066.513**	**1.330**	**1.076**	**1.159.917**	**9.591**
Market share (%)		**89,09%**	**0,53%**	**0,42%**	**0,03%**	**0,72%**	**2,66%**	**0,02%**	**0,02%**	**0,54%**	**0,06%**	**2,83%**	**0,00%**	**0,00%**	**3,07%**	**0,03%**

3.2.2.3 Supplier Switching

Following the events of 2012 in the retail market, customer switching in 2016 continued to be very limited, possibly reflecting the negative experience of electricity customers that was combined with the exit of large independent suppliers, but more importantly structural problems of the domestic market, which is dominated by the incumbent supplier. The following Table 26 depicts the main figures of supply switching in the interconnected system in 2016:

Table 26	Number of Customers in the interconnected system 2016	Total Consumption 2016 (MWh)	Switching number of customers in 2016	Switching rates % in total no of customers in 2016	Switching rates % in total no of customers in 2015 (%)	Consumption of the switching number of customers 2016 (MWh)	2016 (%)	2015 (%)
Household customers	5.158.597	15.047.984	69.498	1,35%	0,33%	102.690	0,68%	0,18%
Small industrial and LV Customers	1.137.500	9.192.244	34.021	2,99%	1,01%	274.000	2,98%	1,25%
Oher LV customers	309.918	3.384.980	6	0,00%	0,00%	4	0,00%	0,00%
Total LV customers	6.606.015	27.625.208	103.525	1,57%	0,43%	376.693	1,36%	0,51%
Commercial and Industrial MV customers	8.623	8.643.061	1.249	14,48%	7,59%	461.860	5,34%	2,97%
Other MV customers	1.667	1.477.949	1	0,06%	0,00%	174	0,01%	0,00%
Total MV customers	10.290	10.121.010	1.250	12,15%	6,36%	462.034	4,57%	2,52%
Total no of LV and MV customers	6.616.305	37.746.218	104.775	1,58%	0,44%	838.728	2,22%	1,03%

- *Switching number of LV and MV customers in the interconnected system 2015-2016 (estimated numbers), source DEDDIE S.A)*

3.2.2.4 Price monitoring

Prices have been fully liberalized since 01.07.2013. The only regulated tariffs are those under Public Service Obligations, i.e. the social tariffs and the prices offered under the Supplier of Last Resort and Universal Service Supplier services (see Section 3.5.2).

Under Law 4001/2011 (Art. 140, par. 6), RAE monitors deregulated retail prices and may intervene ex-post, if an abusive behavior is identified (prices are too high, therefore abusive towards consumers, or too low, therefore abusive towards competitors).

In its Decision 692/2011 (and, subsequently, in the new Electricity Supply Code), RAE set the general principles for tariff setting in the competitive market. Per these principles, tariffs should be simple, transparent, cost-reflective and avoid cross-subsidies; they must consider consumer category characteristics, offer real choices to the consumers and, where possible, provide incentives for the efficient use of electricity. Special guidelines were provided for large consumers, where it is possible to tailor-make price offers and not to have a general published tariff, to consider the specific characteristics of each customer.

Alternative suppliers offered lower tariffs, compared to PPC, only to certain customer categories. All alternative suppliers publish their tariffs on their websites, while RAE regularly publishes comparative estimates of the 4-monthly bill for residential and small commercial customers under the various tariffs on offer (both from PPC and from the active alternative suppliers). RAE continuously monitors suppliers' pricing information to ensure availability and clarity of information, to the benefit of final consumers, while the retail domestic market evolves and matures further.

3.2.2.4.i *Price-comparison tool.*

To provide clear price information for residential and small commercial consumers, to enable them to avoid misleading marketing practices and choose the best price offer available to them in the retail market, RAE estimates and publishes on a regular basis on its website the final electricity bill (€) for various consumption levels, for residential and small commercial consumers, and for all active electricity suppliers. RAE publishes a simple look-up table per company, with which the consumer can estimate, on a comparable basis, what his/her final bill (over a four-month metering period) would be, under various offers by the different suppliers.

The best offer/ company very much depends on the consumption level of a specific consumer and on consumer category.

3.2.2.4.ii *Tariff deficit.*

There is no tariff deficit regarding the competitive elements of electricity bills (i.e. which cover the activities of the wholesale market and retail business). Also, regarding network use of system costs, any revenue under-recovery is incorporated in the tariffs of following years. For PSO and RES levies, the case is different.

For the PSO levy, although the methodology foresees the same mechanism that applies for network tariffs (i.e. transfer of past under-recovery to tariffs of following years), this has not been implemented in practice as prices are set by law as a transitional measure following a relevant decision by the High Court.

Therefore, although RAE has approved the total cost of compensation for the provision of PSOs up to and including the year 2013, this has not been reflected in the PSO levy. Regarding the RES levy, the levels applied in the past were not sufficient to cover the total cost of the mechanism for supporting renewable generation (i.e. the feed-in tariff system). A deficit was created, which peaked at around €550m in 2013, but has since decreased significantly and is expected to become zero by the end of 2017.

3.2.3 Non-interconnected islands (NII)

All Greek Non-Interconnected Islands (NNIs) are electrified by autonomous electrical systems, which operate under the provisions of Directive 2009/72/EC. Until today, PPC S.A. remains effectively the only supplier and electricity generator from fossil fuels (oil products), in these islands. Renewable energy sources (wind parks and small photovoltaic stations), most which are owned by independent producers (other than PPC S.A.), contribute with a significant percentage in the total NII electricity production per year (not exceeding 15-20% for each NII).

In February 2014, RAE adopted the Operation Code for Non-Interconnected Islands (NII Code, Decision 39/2014, National Gazette B '304 / 02.11.2014), which largely completed the secondary legislation that regulates the operation and the transactions at the NII electrical systems, as provided for by Law 4001 / 2011. Therefore, with the NII Code in effect, the NII markets may be open to competition, for both the production and the supply activities. In addition, on

August 14, 2014, the European Commission granted to Greece (Decision 2014/536/EC) derogation from the provisions of Chapters III and VIII of Directive 2009/72/EC for the NIIs. This Decision followed the relevant applications of the Greek State in December of 2003, based on article 26 of Directive 2004/54/EC, and then in January of 2012, based on article 44 of Directive 2009/72/EC. Per the Commission's above Decision:

All NIIs except Crete are recognized as micro isolated systems per art. 2 par. 27 of the Directive 2009/72/EC, while Crete is characterized as a small isolated system per art. 2 par. 26 of the same Directive.

- Regarding conventional power generation:
  - The Commission acknowledges the distinct nature of the islands in terms of power production, i.e. that substantial problems exist for the operation of conventional power plants within the NII isolated systems. Derogation from Chapter III of Directive 2009/72/EC is granted for the refurbishing, upgrading and/or expanding of PPC's existing power plants until 1.1.2021, but not for new capacity. However, should the authorization procedure for new capacity fail to provide for the satisfactory authorization of new capacity for the isolated systems on the NIIs, the Greek authorities may consider using the provisions of Article 7(3) of Directive 2009/72/EC also for new small conventional capacity. Such new small conventional capacity may for instance include temporary generation capacity that may be made available on a long-term basis without permanent attribution to a specific location.
  - Derogation from the provisions in Chapter III of Directive 2009/72/EC cannot be granted for Crete.

- Regarding electricity supply:
    - Derogation from market opening is granted for a period of 2 years after the entry into force of the NII Code, i.e. until 17 February 2016, for the registers, that are a necessary requirement for market opening, to be established, that may be extended to 5 years after the entry into force of the NII code, i.e. until 17 February 2019, for any of the NII isolated system. However, as the derogation can only be justified where substantial and material problems remain for market opening that are directly attributable to the non-completion of the infrastructure investment program on the NIIs, it should be verified yearly whether such problems persist on a given NII isolated system.

DEDDIE, in compliance with the requirements of the exemption decision, submitted for approval by the RAE, the projected Infrastructure Action Plan. Under this plan, the timetable for the necessary infrastructure should be extended to certain actions and activities for an additional semester, compared with the predictions of the Code of NII. This is because, during the first year of implementing the NII Code revealed the need for further specialization of individual projects, procedures and infrastructures and the necessary checks and certifications may not be completed earlier than the first half of the year 2020 for most systems. Especially for systems that cover 99% of total demand of NII, all the necessary infrastructure will have been implemented within the allotted time in the NII Code, namely in the first half of 2019.

As to the proposed by the Operator timetable for the implementation of infrastructure, RAE found that certain required procedures and actions during the formation period of the NII Code and setting of deadlines, was not possible to estimate accurately and in detail for the installation of infrastructure, as well as their duration. Therefore, objective difficulties emerged that justified deviation of time limits that were laid down in Article 237 of the NII Code.

For this reason, RAE proceeded with Decision 330/2015 on amending the timetable for implementation of infrastructure provided for in Article 237 of the NII and specified in more detail the timing of individual actions, procedures and implementation of projects by the end of the first half of 2019

Subsequently, RAE proceeded to the adoption of the Action Plan by its Decision 389/2015 which imposed certain changes in the submitted schedule of the Action Plan, at its discretion, so that it complies with the requirements of the NII Code (for more about the Non-Interconnected islands see section: 3.4).

3.3 Security of supply

3.3.1 Monitoring the balance of supply and demand

The energy system transformation that Greece is undertaking entails significant structural changes for the energy sector through greater energy efficiency, larger contributions from renewable energies while ensuring the continuous low-carbon nature and security of its electricity supply. This transformation has implications for maintaining energy security in the short to medium term given the ageing of the lignite generation units. It was therefore necessary for Greece to introduce demand response measures and retain a capacity market mechanism in 2016 with a view to ensuring power system adequacy at peak demand and integrating larger shares of intermittent sources of electricity generation (RES).

Security of Electricity Supply in the Winter 2016. In December 2016, Greece experienced electricity supply constraints mainly due to unprecedented unavailability of lignite generation units. With a temperature, much colder than average, ensuring security of supply was challenging. Public Power Corporation had planned maintenance period and the additional brief shutdown of lignite generation units. Import capacity could offset the temporarily reduction of domestic supply. However, electricity import capacity had been lower than expected, with a tight situation in Bulgaria, Italy, fyr Macedonia and Turkey. The first step of TSO after consultation with RAE was to interrupt energy-intensive industrial sites and volunteers to reduce the power demand GW. TSO could then reduce voltage by a limited percentage or GW load, without interrupting supply. In the case of an extreme imbalance between consumption and production, the TSO could finally perform load-shedding through 'programmed and momentary outages' in a rotational basis of less than two hours per consumer (and to specific regions) while preserving supply to sensitive loads and priority customers, such as hospitals and important industries.

Electricity demand and electricity demand peak

Table 27 presents the evolution of annual electricity consumption in the interconnected system, since 2007, as reported by the TSO, ADMIE S.A. According to ADMIE's data, consumption in 2016 had a slight decrease compared to 2015. However, as explained in detail in section 3.2.1.1 (Market Volume), if the RES (mainly PV) production from plants that are connected to the distribution network and not measured by the TSO, is considered then the total consumption (the real consumption) in 2016 was 51,2TWh almost equal to the consumption level in 2015 (51,3 TWh), and showing a modest increase of 2.1%, with respect to the year 2014 (50,23 TWh).

Table 27. Energy and peak electricity demand in the interconnected system, the 10 years period 2007-2016.										
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Electricity consumption excluding pump storage (GWh)	55.253	55.675	52.436	52.329	51.492	50.289	48.451	45.953	46.641	46.478
Peak load MWh	10.610	10.393	9.828	9.902	10.055	9.894	9.161	9.263	9.813	9.135
Note: Consumption at the grid level.										

Installed capacity and security of Supply

Greece's energy sector is shaped by the role of lignite energy, which in 2016 accounted for 23% of the installed capacity of the power mix (including RES) or 32% of the installed capacity of the power mix (excluding RES but including Large Hydro) or 43% of the installed capacity of the power mix excluding all Res (and Hydro). Greece installed capacity for lignite was 3912MW in 2016, -12% compared to the year 2015, while the level of lignite generation was 14898GWh in 2016, sharing 44% of the total domestic generation, excluding RES but including Hydro.). The Installed Natural gas generation capacity accounted for 30,4% of the total installed capacity of the power mix, including all RES with 5239 MW in 2016 but natural gas generation quantity was second with 12622 GWh, after lignite . Hydroelectric installed generation capacity is the third installed capacity generator "fuel" (3173 MW) in the Greek power (capacity) mix but it generated only 4843GWh in 2016 (only 14,5% of the total generation but excluding other RES). These numbers indicate the importance of lignite and natural gas in security of supply.

Market Structure and security of Supply

The electricity wholesale (and retail) market remains highly concentrated. PPC owns and operates all of the 7085 MW of Greek lignite and hydro power capacity. PPC operates more than 95% of all hydropower facilities. While the generation and retail sectors are open to competition, in line with EU directives, actual competition on the generation side is limited to large consumers, as small consumers still have access to a regulated tariff, proposed by incumbent operators, besides so-called market offers proposed by all suppliers (including the incumbent) (for more see section; promoting competition).

STATISTICS FOR GENERATION									
2016									
	DAY AHEAD SCHEDULE			IMBALANCES			TOTAL		
NAME	QUANTITY (MW	AMOUNT (€)	PRICE (€/MWh	QUANTITY (MW	AMOUNT (€)	PRICE (€/MWh	PRODUCTION (MWh)	TOTAL AMOUNT (€)	AVERAGE PRICE (€/MWh)
ELPEDISON ENERGY A.E.									
ELPEDISON A.E.	2.528.359	-113.009.829	-44,7	-71.454	774.534	-10,8	2.488.455	-112.235.296	-45,1
PROTERGIA ΑΓΙΟΣ ΝΙΚΟΛΑΟΣ POWER A.E	1.519.613	-69.875.753	-46,0	-46.803	737.695	-15,8	1.475.216	-69.138.058	-46,9
ΑΛΟΥΜΙΝΙΟΝ ΤΗΣ ΕΛΛΑΔΟΣ ΒΕΑΕ	1.125.302	-48.163.066	-42,8	19.247	-908.396	-47,2	1.145.594	-49.071.462	-42,8
PPC S.A	24.578.497	-1.086.206.746	-44,2	341.022	-21.831.639	-64,0	25.344.903	-1.108.038.385	-43,7
ΗΡΩΝ ΘΕΡΜΟΗΛΕΚΤΡΙΚΗ Α.Ε.	1.655	-82.799	-50,0	3.442	-316.619	-92,0	5.102	-399.418	-78,3
ΗΡΩΝ II ΒΟΙΩΤΙΑΣ Α.Ε.	1.406.122	-63.627.426	-45,3	-64.491	1.734.522	-26,9	1.343.770	-61.892.904	-46,1
ΚΟΡΙΝΘΟΣ POWER A.E.	1.654.910	-74.851.983	-45,2	-94.019	2.322.576	-24,7	1.563.239	-72.529.407	-46,4
ΣΥΝΟΛΟ	**32.814.457**	**-1.455.817.602**	**-44,4**	**86.943**	**-17.487.327**	**-201,1**	**33.366.279**	**-1.473.304.929**	**-44,2**

Table 29 Statistics for imports 2016.

	DAY AHEAD SCHEDULE			IMBALANCES			TOTAL		
NAME	QUANTITY (MW	AMOUNT (€)	PRICE (€/MWh)	QUANTITY (MW	AMOUNT (€)	PRICE (€/MWh)	SETTLED ENERGY (MWh)	TOTAL AMOUNT	AVERAGE PRICE (€/MWh)
ALPIQ ENERGY HELLAS A.E.	52.765	-2.229.953	-42,3				52.765	-2.229.953	-42,3
ALPIQ ENERGY SE	155.700	-6.399.168	-41,1				155.700	-6.399.168	-41,1
AXPO ENERGY ROMANIA S.A.	410.744	-17.048.876	-41,5	-18			410.726	-17.048.876	-41,5
CEZ A.S.	32.464	-1.340.710	-41,3				32.464	-1.340.710	-41,3
DANSKE COMMODITIES A/S	391.643	-16.808.444	-42,9	-44	371	-8,4	391.599	-16.808.073	-42,9
DENCO S.R.L.	2.755	-121.161	-44,0				2.755	-121.161	-44,0
EDELWEISS ENERGIA S.P.A.	54.925	-2.251.312	-41,0	-50			54.875	-2.251.312	-41,0
EDISON TRADING S.P.A	128.212	-5.292.156	-41,3	107	9.580	89,5	128.319	-5.282.576	-41,2
ELECTRADE S.p.A.	15.675	-644.271	-41,1				15.675	-644.271	-41,1
ELEKTRICNI FINANCNI TIM d.o.o.	516.673	-21.642.755	-41,9	-501	26.736	-53,4	516.172	-21.616.018	-41,9
ELPEDISON A.E.	727.214	-30.573.931	-42,0	5	2.439	487,8	727.219	-30.571.492	-42,0
ENSCO S.A.	363.314	-14.907.399	-41,0	-60			363.254	-14.907.399	-41,0
EUNICE TRADING A.E.	9.588	-392.713	-41,0				9.588	-392.713	-41,0
EVN TRADING SOUTH EAST EUROPE EAD	26.315	-1.075.378	-40,9	-53			26.262	-1.075.378	-40,9
EZPADA S.R.O.	229.186	-9.895.012	-43,2	-11	2.931	-266,4	229.175	-9.892.081	-43,2
GEN -I ATHENS Μ.Ε.Π.Ε (SMLLC)	2.766.251	-116.063.431	-42,0	-298	137.901	-462,8	2.765.953	-115.925.529	-41,9
GREEK ENVIRONMENTAL & ENERGY NETWORK A.E.	475.715	-19.856.532	-41,7	-49	1.858	-37,9	475.666	-19.854.674	-41,7
HOLDING SLOVENSKE ELEKTRARNE D.O.O.	171.216	-6.931.489	-40,5	-560	21.702	-38,8	170.656	-6.909.787	-40,5
NECO A.E.	286.645	-12.479.176	-43,5	-40			286.605	-12.479.176	-43,5
NOVAERA ENERGY A.E.	52.253	-2.128.600	-40,7	-30			52.223	-2.128.600	-40,8
NRG TRADING HOUSE S.A.	209.964	-9.045.771	-43,1	-15			209.949	-9.045.771	-43,1
PROTERGIA A.E.	3.277	-144.352	-44,0				3.277	-144.352	-44,0
PROTERGIA ΑΓΙΟΣ ΝΙΚΟΛΑΟΣ POWER A.E.	480.008	-20.358.439	-42,4	-17			479.991	-20.358.439	-42,4
SENTRADE A.E	101.367	-4.201.138	-41,4	-26			101.341	-4.201.138	-41,5
STATKRAFT MARKETS GMBH	190.382	-7.981.374	-41,9				190.382	-7.981.374	-41,9
VOLTERRA A.E.	72.473	-3.024.313	-41,7	-57	3.573	-62,7	72.416	-3.020.740	-41,7
WATT AND VOLT A.E.	57.786	-2.407.892	-41,7	-144	6.387	-44,4	57.642	-2.401.504	-41,7
ΑΝΩΝΥΜΗ ΕΤΑΙΡΕΙΑ ΤΣΙΜΕΝΤΩΝ ΤΙΤΑΝ	42.869	-1.706.678	-39,8	-32			42.837	-1.706.678	-39,8
ΔΗΜΟΣΙΑ ΕΠΙΧΕΙΡΗΣΗ ΗΛΕΚΤΡΙΣΜΟΥ Α.Ε.	1.960.386	-83.960.513	-42,8	-5.259	166.438	-31,6	1.955.127	-83.794.074	-42,9
ΗΡΩΝ ΘΕΡΜΟΗΛΕΚΤΡΙΚΗ Α.Ε.	747.961	-31.505.477	-42,1	-176	676	-3,8	747.785	-31.504.800	-42,1
ΙΝΤΕΡΜΠΕΤΟΝ - ΔΟΜΙΚΑ ΥΛΙΚΑ Α.Ε.	8.984	-402.363	-44,8	-18			8.966	-402.363	-44,9
ΤΕΡΝΑ ΕΝΕΡΓΕΙΑΚΗ ΑΒΕΤΕ	3.739	-176.212	-47,1	5	492	98,5	3.744	-175.719	-46,9
ΣΥΝΟΛΟ	**10.748.450**	**-452.996.987**	**-42,1**	**-7.341**	**381.086**	**-51,9**	**10.741.109**	**-452.615.901**	**-42,1**

Table 30: Statistics for Customers' Supply

	DAY AHEAD SCHEDULE			IMBALANCES			TOTAL		
NAME	QUANTITY (MW	AMOUNT (€)	PRICE (€/MWh	QUANTITY (MW	AMOUNT (€)	PRICE (€/MWh	SETTLED ENERGY (MWh)	TOTAL AMOUNT (€)	AVERAGE PRICE (€/MWh)
ELPEDISON A.E.	1.088.377	47.280.990	43,4	-27.552	-1.230.479	44,7	1.060.825	46.050.511	43,4
GREEK ENVIRONMENTAL & ENERGY NETW	202.228	8.723.211	43	-36.942	-1.662.878	45,0	165.286	7.060.333	43
NOVAERA ENERGY A.E.	8.117	357.034	44,0	832	37.239	44,8	8.949	394.273	44,1
NRG TRADING HOUSE S.A.	339.270	14.385.772	42,4	-61.372	-2.655.523	43,3	277.898	11.730.250	42,2
PROTERGIA ΑΓΙΟΣ ΝΙΚΟΛΑΟΣ POWER A.E	1.126.659	48.812.008	43,3	4.137	142.852	34,5	1.130.796	48.954.860	43,3
VOLTERRA A.E.	258.952	11.141.696	43,0	-47.653	-2.108.874	44,3	211.299	9.032.823	42,7
WATT AND VOLT A.E.	264.573	11.467.376	43,3	-52.339	-2.321.973	44,4	212.234	9.145.402	43,1
ΑΛΟΥΜΙΝΙΟΝ ΤΗΣ ΕΛΛΑΔΟΣ ΒΕΑΕ	21	931	44,3	137	6.472	47,3	158	7.402	46,9
ΑΝΩΝΥΜΗ ΕΤΑΙΡΕΙΑ ΤΣΙΜΕΝΤΩΝ ΤΙΤΑΝ	7.073	291.191	41,2	-275	-11.426	41,5	6.798	279.765	41,2
BI.ENEP A.E.	1.724	88.261	51,2	-361	-18.911	52,4	1.363	69.351	50,9
PPC. S.A	45.411.133	1.975.154.756	43,5	278.803	13.801.444	49,5	45.689.937	1.988.956.201	43,5
ΕΛΛΗΝΙΚΑ ΤΑΧΥΔΡΟΜΕΙΑ ΑΕ	10.991	478.559	43,5	-215	-6.133	28,5	10.776	472.425	43,8
ΗΡΩΝ ΘΕΡΜΟΗΛΕΚΤΡΙΚΗ Α.Ε.	1.260.663	54.593.014	43,3	-46.643	-2.101.120	45,0	1.214.019	52.491.894	43,2
ΗΡΩΝ II ΒΟΙΩΤΙΑΣ Α.Ε.	2.363	98.141	41,5	4.197	186.430	44,4	6.561	284.571	43,4
ΙΝΤΕΡΜΠΕΤΟΝ - ΔΟΜΙΚΑ ΥΛΙΚΑ Α.Ε.	11.035	493.408	44,7	-391	-18.046	46,1	10.644	475.362	44,7
ΚΟΡΙΝΘΟΣ POWER A.E.	1.795	71.729	40,0	4.014	177.127	44,1	5.809	248.856	42,8
OTE estate	26.277	1.203.463	45,8	-4.803	-240.289	50,0	21.474	963.173	44,9
OTE A.E.	1.495	62.073	41,5	-233	-10.074	43,2	1.262	52.000	41,2
ΠΡΟΜΗΘΕΥΤΗΣ ΚΑΘΟΛΙΚΗΣ ΥΠΗΡΕΣΙΑΣ	83.922	3.600.950	42,9	-7.660	-266.217	34,8	76.263	3.334.733	43,7
ΣΥΝΟΛΟ	**50.106.670**	**2.178.304.562**	**43,5**	**5.680**	**1.699.622**	**299,2**	**50.112.350**	**2.180.004.185**	**43,5**

Table 31: Statistics for Exports.

	DAY AHEAD SCHEDULE			IMBALANCES			TOTAL		
NAME	QUANTITY (MW	AMOUNT (€)	PRICE (€/MWh	QUANTITY (MW	AMOUNT (€)	PRICE (€/MWh	SETTLED ENERGY (MWh)	TOTAL AMOUNT (€)	AVERAGE PRICE (€/MWh)
ALPIQ ENERGY SE	35.871	1.581.971	44,1				35.871	1.581.971	44,1
AXPO ENERGY ROMANIA S.A	46.367	2.043.712	44,1	29	6.487	223,7	46.396	2.050.198	44,2
CEZ AS.	2.400	109.855	45,8				2.400	109.855	45,8
DANSKE COMMODITIES A/S	415.892	19.076.342	45,9	319	103.213	323,6	416.211	19.179.555	46,1
DENCO S.R.L.	3.671	167.237	45,6				3.671	167.237	45,6
DUFERCO ENERGIA S.P.A	6.206	272.350	43,9				6.206	272.350	43,9
EDELWEISS ENERGIA S.P.A.	247	10.221	41,4				247	10.221	41,4
EDISON TRADING S.P.A	14.326	644.403	45,0	7	648	92,6	14.333	645.051	45,0
ELECTRADE S.p.A.	6.692	285.801	42,7				6.692	285.801	42,7
ELEKTRICNI FINANCNI TIM d.o.o.	33.283	1.555.460	46,7				33.283	1.555.460	46,7
ELPEDISON A.E.	19.344	852.509	44,1				19.344	852.509	44,1
ENSCO S.A.	229.502	10.045.660	43,8				229.502	10.045.660	43,8
EVN TRADING SOUTH EAST EUROPE EAD	21.309	1.102.961	51,8				21.309	1.102.961	51,8
EZPADA S.R.O.	26.000	1.234.545	47,5				26.000	1.234.545	47,5
GEN-I ATHENS M.E.Π.E (SMLLC)	1.007.058	44.483.742	44,2	4.791	341.050	71,2	1.011.849	44.824.792	44,3
GREEK ENVIRONMENTAL & ENERGY NETW	47.839	2.322.574	48,5				47.839	2.322.574	48,5
HOLDING SLOVENSKE ELEKTRARNE D.O.O	12.817	533.706	41,6	700	63.742	91,1	13.517	597.448	44,2
NECO A.E.	21.941	977.618	44,6				21.941	977.618	44,6
NRG TRADING HOUSE S.A.	30.349	1.329.012	43,8	30	13.655	455,2	30.379	1.342.667	44,2
PROTERGIA ΑΓΙΟΣ ΝΙΚΟΛΑΟΣ POWER A.E	53.203	2.209.872	41,5				53.203	2.209.872	41,5
SENTRADE A.E	737	41.327	56,1				737	41.327	56,1
STATKRAFT MARKETS GMBH	42.625	1.877.690	44,1				42.625	1.877.690	44,1
VOLTERRA A.E.	2.591	102.224	39,5				2.591	102.224	39,5
WATT AND VOLT A.E.	9.364	466.866	49,9				9.364	466.866	49,9
ΑΝΩΝΥΜΗ ΕΤΑΙΡΕΙΑ ΤΣΙΜΕΝΤΩΝ ΤΙΤΑΝ	472	21.978	46,6				472	21.978	46,6
PPC S.A	69.456	2.955.474	42,6	114	9.158	80,3	69.570	2.964.632	42,6
ΗΡΩΝ ΘΕΡΜΟΗΛΕΚΤΡΙΚΗ Α.Ε.	37.714	1.723.510	45,7				37.714	1.723.510	45,7
ΤΕΡΝΑ ΕΝΕΡΓΕΙΑΚΗ ΑΒΕΤΕ	1.041	53.685	51,6	10	506	50,6	1.051	54.190	51,6
ΣΥΝΟΛΟ	**2.198.318**	**98.082.305**	**44,6**	**6.000**	**538.459**	**89,7**	**2.204.318**	**98.620.764**	**44,7**

3.3.2 Generation adequacy in the interconnected and non-interconnected Systems.

The Greek electricity generation mix has a diversified structure. Lignite units generated 14.898 GWh, natural gas units generated 12.680 GWh, RES units generated 10.191 GWh, Hydro units generated 4.843 GWh and import flows supply almost 10.966 GWh, in 2016. We note that RES units including Hydro units for first time, were the largest generators of the Greek power generation mix in 2016, generated 15.043GWh.

Traditionally, the Greek power system has been characterized by a structural overcapacity However, the Greek lignite power generation units are ageing, thus, the maintenance time for the lignite power plants is extended and the closure of some of the lignite power plants increase the risk for security of supply. Furthermore, most of the new capacities are renewable energy sources, mainly wind power and solar PV. Imports In addition, supplies to Greece from neighboring countries during peaks may be compromised by the situation in Bulgaria and lower imports from Italy. Because of growing uncertainties linked to the large amount of lignite plants under maintenance and decommissioning of coal/oil/ power plants and growing concern about security of supply at times of peak demand, import capacity is necessary for Greece to maintain its security of supply.

On the demand side, Greece has seen a large decline in electricity (industrial) demand the last 7 years with the relocation of industry and the impact of energy efficiency and the economic slowdown (economic depression). Forecasts expect a flat electricity-demand curve in the coming decade with a maximum of 1% increase per year. (The share of lignite in the electricity mix would increase if electricity consumption declined in the coming years, which would not be in line with the target of the government.) Therefore, the main risk for security of supply is the thermo-sensitivity of the demand and the peak load during cold snaps. In winter periods electricity consumption is very sensitive to temperature owing to the high penetration of electric heating and air conditioning.

Up to now the TSO does guarantee that it can fulfill the security-of-supply standard (loss of load expectation <= 3 hours) in all scenarios. Increasing flexibility is also needed to cope with *intermittent* renewable energies, and *ii)* rising peak demand, while the real value of flexibility is not yet fully recognized. Therefore, the government decided to remain a capacity mechanism by ministerial decree in January 2015, as described above. Avoiding the decreasing capacity margins during all winters and Summers up to 2019-20, as demand peaks increase (though at lower growth rates) while peak generation decreases every year and baseload coal or gas-fired power plants were closed in 2013-15. Greece should consider generation adequacy in neighboring countries' (A regional generation adequacy assessment, based on a shared methodology among TSOs was presented in the framework…based on new electricity market design)

The new capacity mechanism aims to deal with Summer and winter peak load to improve security of supply and to operate the system efficiently with the increasing share of the renewables in generation. The implementation of the capacity mechanism is a learning process for all actors, with several open questions on how capacity reserves held abroad, and thus interconnection capacity, can be considered and how the level of the estimated peak capacity

For the coming years, an important role for demand response is expected to meet peak demand, provide flexibility, and deal with increasing renewable targets. This role is expected to be based on market mechanisms (explicit DR) instead of being based on tariffs (implicit DR), so that consumers benefit from lower electricity prices. Pilot projects are being carried out to test the response of demand.

In the medium - term, and in addition to DR, the integration of renewable energy sources will be encouraged through the introduction different markets (day-ahead, intraday, forward balancing markets and ancillary services) and imports capacity. In this regard, developments at European level and regional level on the new energy market design will be considered by Greece. For instance, import capacity is necessary for Greece to maintain its security of supply, thus the introduction of a day ahead electricity market in Bulgaria, in 2016 and the expected operation of a Bulgarian intraday market in 2017 increase the import capacity of the day ahead Greek electricity market, improve the liquidity of the Greek electricity market and improve the security of electricity supply.

The development of renewable energies, the increase in import capacity, the activation of demand response mechanisms and energy efficiency will enable to offset the decrease of lignite generation.

Monitoring Adequacy of the Interconnected system and Non-Interconnected (islands) system.

a) The Interconnected system. In the context of the current legislation, the Transmission System Operator, ADMIE S.A., submitted in 2014 to RAE, a Generation Adequacy Report for the period 2016-2024. The purpose of this report is to highlight potential future risks with regards to the ability of the interconnected power system to respond adequately to changes in electricity demand, foreseen for the time-period under consideration, which was extended compared to the previous year's study from seven to ten years' time. The 2016 Generation Adequacy Report examined alternative demand and generation scenarios, which were formed based on relevant estimates-forecasts by the Transmission System Operator. Specifically, the assumptions concerned a) electricity demand projections (peak and annual), taking into account the relevant network development plans that are expected to be realized (e.g. the electric connections of the Cyclades islands and the island of Crete with the mainland electricity grid), and b) generation projections, taking into account the decommissioning of old existing plants, new generation plants that are expected to be commissioned, and the expected penetration of RES installations of various technologies. For the first time and given the economic conditions in Greek power market, also scenarios for unit economic retirement were taken under consideration.

Two approaches, namely deterministic and probabilistic, were applied to calculate a series of reliability indicators based on hourly system simulations projecting the system to the future following various scenarios about demand and supply. The indicators addressed issues of concern regarding generation adequacy in the future, including capacity adequacy and flexibility adequacy of the system, the latter being increasingly required due to developing variable renewables. In addition, the study reported on reliability indicators also by applying the standard approach of ENTSO-E (European Network of Transmission System Operators for Electricity).

RAE provided comments/observations on the Generation Adequacy Report to the TSO, with a view to incorporating them in the next submitted reports. The objective of the Regulatory Authority is to establish a systematic reporting and evaluation procedure of the generation adequacy, so that the security of electricity supply in the country can be monitored in the best possible way.

b) The Non-Interconnected islands system: As far as the non-interconnected (island) system is concerned, there are 32 autonomous electricity systems in Greece today, with an annual maximum demand (peak) ranging from a few tens of kW (e.g. the Antitheta island, peaking around 100 kW), up to several hundreds of megawatts (e.g. Crete, peaking around 600 MW). Currently, the energy demand on these islands is covered primarily by local power stations, consisting of conventional thermal power plants using heavy fuel oil or diesel, while a part of this (up to 16,82%) is covered by RES (wind and photovoltaic plants). The sole producer of electricity from conventional units in these non-interconnected systems is currently PPC, while RES power stations on the islands are predominantly privately owned.

The inability of existing RES plants to provide guaranteed power to the local island systems inevitably leads to continued strengthening of the conventional power resources of each island, with new thermal units designed to meet both peak demand and the necessary reserve capacity. It is noted that to ensure sufficient resources and minimize the risks to security of supply, especially in the event of power loss, in each autonomous island system, and in addition to the required power to meet the maximum demand (peak), reserve conventional capacity is also installed and kept at standby status, to cover the possibility of loss of the largest power unit in each autonomous system. Moreover, per Decision 2014/536/EE of the European Commission, exemption has been granted for renovation, upgrading and expansion of thermal units on non-interconnected islands, to address security of supply issues, with special focus on the necessity of interconnections.

3.3.2.1 Introducing and revising the generation capacity mechanisms

Introducing and revising the generation capacity mechanisms for the efficient operation of the wholesale market, the security of supply and generation adequacy;

Due to the dominant position of PPC in the wholesale market, the increasing share of RES in electricity generation, additional (supplementary) auxiliary capacity generation mechanisms have also been introduced by the Regulator (RAE) for the efficient operation of the market and the strengthening of security of supply. Auxiliary capacity generation mechanisms exerted a substantial impact on market outcomes, but were revised during 2013 2014 and 2015 in crucial aspects to yield more competitive outcomes

The following rules or auxiliary generation capacity mechanisms were and are used for the efficient operation of the wholesale market, the security of supply and Generation Adequacy in Greece:

- *A lower limit is imposed on generators’ offers*, equal to the minimum variable cost of each unit in each trading period. This limit had been introduced because, in the current structure, the incumbent has a strong incentive to suppress wholesale prices. An exception to the previous rule is the so-called “30% rule”, which allows generators to offer 30% of their plant’s capacity at a price below its minimum variable cost, if the total weighted average of their bids is still at or above their minimum variable cost. The “30% rule” was abolished on 31.12.2013.

- *A price cap offer.* A cap of 150 €/MWh has been imposed on all generators’ offers up to 2015. With a new decision RAE, has increased the imposed cap on all generators offers from 150 €/MWh in 2015 to 300 €/MWh in 2016.

- *A cost-recovery mechanism* ensures that generators dispatched by the TSO, beyond the day-ahead schedule, are remunerated based on their declared minimum variable costs plus a margin. This margin had been set previously to 10%, but it was abolished in July 2013, being considered a market distortion, as generators used the mechanism to get dispatched over prolonged time intervals, exhibiting stable profiles (of limited sensitivity to the demand level), but imposing unnecessary costs on the system. After this distortion was corrected, the mechanism better expressed its objective as a safety net that averts producers' losses when dispatched due to reserve requirements (not necessarily energy balance requirements) and inter-temporal technical constrains. Nevertheless, the mechanism was removed on 01.07.2014. In 2015 however, RAE evaluated the implications of the mechanism abolition and with its Decision 392/2015, (re)introduced a more stringent version of the cost recovery mechanism.

- *A Capacity Adequacy Mechanism (CAM)* is applied for the partial recovery of capital costs of generating plants, with suppliers being obliged to buy capacity certificates from generators. In 2014, the value of these certificates remained regulated, due to the very high market share of PPC in the retail market (>97%) and the consequent lack of liquidity and ability for contracting between suppliers and generators. The value of the capacity certificate was set in July 2013 from 45,000 €/MW/year (a level set back in November 2010) to 56,000 €/MW/year. The transitory regulated mechanism expired 31.12.2014 and in line with the recent European Guidelines a new market-based methodology (Transitory Flexibility Remuneration Mechanism, TFRM), was elaborated in 2016.

- *A Transitional Flexibility Remuneration Mechanism (FRM).* Although no significant changes in the rules of the wholesale market (a mandatory pool – day ahead market) were introduced during 2016, the auxiliary capacity generation mechanisms (Cost Recovery Mechanism and the Transitional Capacity Adequacy Mechanism) which exerted a substantial impact on market outcomes, had already revised in crucial aspects in 2015, to yield more competitive outcomes taking the form of a Transitional Flexibility Remuneration Mechanism (FRM). Thus, the European Commission approved finally a Transitional Flexibility Remuneration Mechanism (FRM) for one more year as a transitional measure to the target model C (2016)1791 final/31.03.2016. The mechanism compensates certain electricity generators in the Greek interconnected electricity system for the provision of flexibility services to the Greek Electricity Transmission System Operator, ADMIE S.A. On instruction of from the TSO and subject to a specified notice period, beneficiaries increase or decrease the amount of electricity injected into the electricity system at a specified minimum rate on a multi hour time scale. The mechanism will operate for a maximum period of 12 months starting in May 2016 and ending in April 2017.

  With the law 4389/2016, the approved by the European Commission Transitional Flexibility Remuneration Mechanism (FRM) was transposed into the Greek legislation. Per the Law 4389/2016 and the commitments of the national authorities to the European Commission for the transitional character of the FRM in the domestic wholesale market (2016-2017)

Until December 2014 Greece applied instead a transitory capacity assurance mechanism consisting of direct remuneration of capacity availability of plants. The impact on system adequacy of a hypothetical premature decommissioning of two combined cycle Gas turbine units (400MW each) which are currently the main providers of the flexibility services shows lower levels of system security of supply.

In accordance with the provision of the Energy Law, the Hellenic Republic designed in 2005 a decentralized capacity assurance mechanism (permanent mechanism) The mechanism was supposed to be based on the bilateral trading of capacity certificates. These were to be issued by dispatch able power plants – in proportion to their capacity and held by Load representatives (suppliers and self-supplied consumers). The latter were under the obligation of holding an enough capacity certificates to cover their load at peak times.

A permanent Capacity Assurance Mechanism (A permanent CAM) was never implemented because of the asymmetry between the vertically integrated incumbent and the small independent generators which have not achieved direct load serving business. The main argument was that a permanent mechanism would have allowed the incumbent (PPC S.A.) to acquire capacity certificates internally, with the consequences that there would be no demand for capacity contracts addressed to the independent generators.

3.3.2.2 Capacity Flexibility Generation (Reserve) Mechanism.

Eligible generation units. RAE with an open invitation called any interested generator to submit its application for the candidacy of eligible generator (17.08.2016) to meet the criteria /technical standards to gain the status of an eligible generation unit Eligible generators can be the units which have the availability of a distance remote control system such that the TSO can take the full control of the units whenever (The TSO) it needs to use them. In addition, the eligible units should have an increasing flexibility on generation capacity to provide flexible (additional) generation capacity 8MW/min and for a minimum period of 3 successive hours. Such characteristics have only the hydroelectric units and the Combine Cycle Gas Turbine which are connected to the interconnected (mainland) system. The level of compensation of the eligible units for the flexibility capacity services defined to 45€/Kw*year of available capacity with the maximum payment per unit at 15 million euro and the total maximum annual payment for all units at 225 million Euro.

Table 32: List of Eligible generation units with RAE's Decision (357-386/2016):

Generation Capacity Reserve Unit/ Owner	Reserve Capacity (MW)	Maximum Compensation (€)	Starting Operation Day
Hydro Agra/ PPC	3,33	149.850	1.5.2016
Hydro Asomaton/ PPC	19,775	889.875	1.5.2016
Hydro Edessa/ PPC	3,077	138.465	1.5.2016
Hydro Thesavrou1/ PPC	21,81	981.450	1.5.2016
Hydro Thesavrou II / PPC	21,81	981.450	1.5.2016
Hydro Thesavrou III/ PPC	21,81	981.450	1.5.2016
Hydro Kastrakiou PPC	97,862	4.403.790	1.5.2016
Hydro Kremaston/ PPC	132,419	5.958.855	1.5.2016
Hydro Ladona/ PPC	30,623	1.378.035	1.5.2016
Hydro River Aoou /PPC	22,479	1.011.555	1.5.2016
Hydro Plastira / PPC	25,219	1.134.855	1.5.2016
Hydro Platanovrisi/ PPC	31,784	1.430.280	1.5.2016
Hydro Polifitou/PPC	62,089	2.794.005	1.5.2016
Hydro Pournariou/ PPC	45,042	2.026.890	1.5.2016
Hydro Pournariou II/ PPC	5,699	256.455	1.5.2016
Hydro Stratou/ PPC	42,082	1.893.690	1.5.2016
Hydro Sfekias PPC	32,897	1.480.365	1.5.2016
Hydro aliveriou / PPC	384,823	15.000.000	1.5.2016
Hydro Komotinis/ PPC	452,325	15.000.000	1.5.2016
Hydro Lavriou IV/ PPC	496,844	15.000.000	1.5.2016
Hydro Lavriou V/ PPC	326,900	9.108.419,18	17.9.2016
CCGT I/ Heron	42,769	1.613.504,47	29.6.2016
CCGT II Heron II/Ήρων	46,434	1.751.770,36	29.6.2016
CCGT Heron III	43,169	1.628.594,88	29.6.2016
CCGT Thessaloniki Elpedison	393,292	15.000.000	1.5.2016
Thisvi/ Elpedison	398,258	15.000.000	1.5.2016
CCGT Heron II/	419,070	15.000.000	1.5.2016
CCGT/ Korinthos Power	426,109	15.000.000	1.5.2016
CCGT/ Protergia	424,151	15.000.000	1.5.2016
CCGTALOUMINIO	198,333	8.924.985	1.5.2016

Market settlement procedures Guidelines issued by RAE, October 2016 Decision no 403/2016 Sanctions/ in 2017

3.3.2.3 A Permanent Capacity (Generation Reserves) Remuneration Mechanism.

In 2016, RAE taking into consideration the current conditions in the electricity market in Greece, the European Energy Law, the Commission Guidelines for State aid in the energy sector and the environment, European Commission's mid-term evaluation Report on electricity capacity remuneration mechanisms and the special characteristics and needs of the Greek electricity system and Law 4336/2015, developed and competed its proposal for a permanent remuneration capacity reserve mechanism. Its proposal was under public consultation from 25.07.2016 to 23.09.2016

The permanent mechanism has main objective to increase the security of supply of the system avoid the risks of the premature closure of generation units (due to ageing or maintenance), give the signals for new investment needs with specific technical standards. The implementation of the mechanism will be based on open competitive procedures (auctions) offering to the TSO Reliability Options Rights for a defined period of time the generation capacity needed by the eligible generator units. The rights will be purchased by the TSO from the eligible generator units on a defined administrative price (Strike price). The rights will be based on a Contract for Difference which will include provisions for avoiding windfall profits for the generators. RAE taking into consideration the inputs from the public consultation is developing further the proposed permanent mechanism in cooperation with the Ministry of energy. RAE in cooperation with the Ministry is expecting to notify the final proposed permanent capacity mechanism to the Commission (DG Competition), in 2017.

3.3.2.4 Demand Side Response Measures. Interruptible load services (ILS).

Regarding interruptible load services (ILS). The Greek Law 4342/2015 (Official Government Gazette FEK A’ 143/09.11.2015 has integrated EU Energy efficiency Directive (henceforth EED) 2012/27, which requires among others, a) member states to adopt demand response measures, b) legal and personal entities to provide balancing and/or ancillary services and c) the regulator to expand its monitoring role for the successful implementation of the energy efficiency directive in the market.

TSO has the right to interrupt load services of the eligible High Voltage consumers in the interconnected system for a specific period of time, at a pre-defined maximum Load level. For its action, the TSO compensates the eligible High Voltage consumers in the interconnected system for the provision of the demand response measures. A Reserves Account for Security of Supply has been issued by the TSO (ΕΛΑΑΕ) The financing of the account is based on a levy imposed to all the active generators.

In 2016, the Greek TSO (ADMIE), organized 5 auctions of two types of interruptible load services (ILS). ADMIE defined two offered types of interruptible load services, as follows

Table 33 Types of Interruptible load services (ILS)	Warning time	Maximum time of order	Maximum time per year
Type 1*	2 hours	48 hours	144 hours
Type 2**	5 minutes	1 hour	24 hours

*Minimum time between two successive orders for the type 1 interruptible load services (ILS) is 1 day. Maximum no of orders of type 1 ILS is 3orders/month.

**Minimum time between two successive orders for the type 2 ILS is 5 days. And the maximum no of orders of the type 2 ILS, is 4orders/month.

The first two auctions (one auction for every type of ILS), was organized by the Greek TSO (ADMIE) and took place on 29/2/2016. The two auctions covered the period from March 1st to March 31st 2016. For every action the offered load capacity was 500MW. The second two auctions (one auction for every type of ILS) was organized by the Greek TSO (ADMIE) on March, both auctions covered the period from 1st April to 30.04.2016. for thee type 1 ILS auction, the offered load capacity was 650MW and for the type 2 ILS the offered capacity was 850. The third two auctions was organized by the TSO on April and took place on 27/4/2016. Both auctions covered the period from May 1st to September 30th. For the type 1 ILS auction, the offered load capacity was 750 MW. For the type 2 ILS auction the offered capacity was 900MW. The fourth two auctions for the year 2016 were organized by the Greek TSO and took place on 27/9/2016. Both auctions covered the period from October 1st 2016 to December 31st 2016. For the type 1 ILS auction, the offered load capacity was 550MW, and for the type 2 ILS auction, the offered load capacity was 650MW. The fifth two type auctions were organized by the Tso on December. Both auctions covered the period from 1st January 2017 to 31st March 2017. For the type 1ILS the offered load capacity was 750MW and for the second type ILS auction the offered capacity was 900MW. The allowed minimum bid offer of each participant was not less than 3 MW. All auctions were successful, (demand excessed supply), see tables 34,35:

Table 34:	Type 1 of Interruptible load capacity services (ILS 1 services) Auctions in 2016					
Month of Auction	Period of Auctions	Marginal price (€/MW-year)	Number of Participants	Maximum Load Capacity Offered (MW)	Total Interruptible Load capacity asked (MW)by the TSO	Difference between the Load Capacity offered and Load capacity asked (MW)
February	01.03.2016 - 31.03.2016	30.000	24	769,5	500	269,5
March	01.04.2016 - 30.04.2016	30.000	22	802,6	650	152,6
April	01.05.2016 - 30.09.2016	48.600	24	807,6	750	57,6
September	01.10.2016 - 31.12.2016	49.900	23	743,3	550	193,3
December	01.01.2017 - 31.03.2017	50.000	27	842,8	750	92,8

Table 35: Type 2 of Interruptible load capacity services (Type ILS 2 services), auctions in 2016.						
Month of Auction	Auction period	Marginal price (€/MW-year)	Number of Participants	Maximum Load capacity Offered (MW) (MW)	Total Interruptible Load capacity asked (MW)by the TSO	Difference between the Load Capacity offered and Load capacity asked (MW)
February	01.03.2016 - 31.03.2016	10.000	27	1045,4	500	545,4
March	01.04.2016 - 30.04.2016	21.900	24	1036,5	850	186,5
April	01.05.2016 - 30.09.2016	47.600	28	1091,0	900	191,0
September	01.10.2016 - 31.12.2016	49.300	28	996,8	650	346,8
December	01.01.2017 - 31.03.2017	48.000	31	1111,7	900	211,7

The implementation of the capacity mechanisms including the demand response mechanisms[6], is a learning process for all actors, with a number of open questions how capacity reserves held abroad, and thus interconnection capacity, can be taken into account and how the level of the estimated peak capacity will need to evolve over time.

Currently, the European Commission has opened an in-depth investigation to assess whether German plans to set up an electricity capacity reserve comply with EU state aid rules. The Commission has concerns that the measure may distort competition and favor power plant operators over demand response operators.

[6] Capacity mechanisms are measures taken by Member States to ensure that electricity supply can match demand in the medium and long term. They are designed to support investment to fill the expected capacity gap and ensure security of supply. Typically, capacity mechanisms offer additional rewards to capacity providers, on top of income obtained by selling electricity on the market, in return for maintaining existing capacity or investing in new capacity needed to guarantee security of electricity supplies. Capacity mechanisms can potentially support not only power generation but also demand response measures (e.g. incentives to households and businesses to reduce electricity consumption at peak times).

3.4 The Non-Interconnected islands system (NIIs);

As far as the non-interconnected (island) system is concerned, there are 32 autonomous electricity systems in Greece today, with an annual maximum demand (peak) ranging from a few tens of kW (e.g. the Antikythera island, peaking around 100 kW), up to several hundreds of megawatts (e.g. Crete, peaking around 600 MW). Currently, the energy demand on these islands is covered primarily by local power stations, consisting of conventional thermal power plants using heavy fuel oil or diesel, while a part of this (up to 16,82%) is covered by RES (wind and photovoltaic plants). The sole producer of electricity from conventional units in these non-interconnected systems is currently PPC, while RES power stations on the islands are predominantly privately owned. In the non-interconnected islands, 32 autonomous power systems currently operate without any wholesale electricity market. In all these autonomous power systems, the Public Power Corporation (PPC) is the only conventional power producer using oil and heavy diesel as a fuel.

3.4.1 Electricity Supply Structure.

In the non – interconnected islands 32 autonomous power systems currently operate without any wholesale electricity market (i.e. forward electricity market, day ahead electricity market, intraday electricity market, balancing market e.t.c)

In all these autonomous power systems, the PPC is the only conventional power producer (using heavy oil or diesel as a fuel). There are several RES power producers (including a PPC subsidiary) and only one existing supplier (PPC) in all islands, except Crete where the market is open to other suppliers from June 2016.

In all 32 systems, currently neither the producers nor the suppliers submit daily offers for their production or for their customers' loads. The dispatching of the units is done to achieve the lowest cost, maximizing at the same time the contribution of RES production, considering also the security of supply. The network operator in the non-interconnected islands in DEDDIE SA (The Hellenic Distribution Network Operator).

Thus, in those systems there is no system marginal price but an estimated clearance price of energy. The estimation is done monthly, based on the variable costs of the conventional power units for each of all these autonomous power systems, pursuant to Law 4001/2011 and the Code of operation of the non - Interconnected islands. PPC as the only supplier, buys all the produced electricity (including the RES production in each system) at this price.

The inability of existing RES plants to provide guaranteed power to the local island systems inevitably leads to continued strengthening of the conventional power resources of each island, with new thermal units designed to meet both peak demand and the necessary reserve capacity. It is noted that to ensure sufficient resources and minimize the risks to security of supply, especially in the event of power loss, in each autonomous island system, and in addition to the required power to meet the maximum demand (peak), reserve conventional capacity is also installed and kept at standby status, to cover the possibility of loss of the largest power unit in each autonomous system. Moreover, per Decision 2014/536/EE of the European Commission, exemption has been granted for renovation, upgrading and expansion of thermal units on non-interconnected islands, to address security of supply issues, with special focus on the necessity of interconnections.

3.4.2 Electricity Generation Capacity and Electricity Demand.

The share of RES' generation in the total electricity generation of the 32-autonomous power system was 15,6% in 2016. In Crete, the largest island of the non- interconnected system the share of RES in total generation was 19,03%. The level of demand of the 32 autonomous non-interconnected islands varies significantly;

19 out of 32 have a peak demand level not more than 10MWh.

11 out of 32 have a peak demand level from 10 MWh up to 100MWh.

And only 2 autonomous non-interconnected islands have a peak demand level over 100MWh (Crete, Rhodes).

The annual electricity demand among the autonomous non - interconnected systems varies too, from few hundreds of MWh (Agathonisi) up to few TWh (Crete), see table below.

According to the EU Directive 2009/72, all the non- interconnected islands except for Crete are classified as "isolated micro grids".

Per Law 3468/2006, for electricity generation from; RES generation plants, Hybrid generation plants, conventional generation plants, on the non- interconnected islands any potential investor /generator must submit its application to RAE to be approved by the Regulator for an electricity generation license. However, EU directive 2009/72/EC (art 44) grants the right of exceptions for isolated microgrids with annual electricity consumption less than 500GWh in 1996. Such exemptions have a limited period (few years). Law 4001/2011 article 139 transposed to the Greek legislation the right of exemptions. With the Law 4414/2016 with the granted exemptions, the generators of the non-interconnected islands had to fulfill specific requirements on the non-interconnected islands (transition period, examine alternatives of electricity supply i.e. domestic generation or system interconnection, costs of infrastructure development, a new distribution operation code for the autonomous non-interconnected islands, a List of Registered generators). The transition period for the Greek non-interconnected islands was until 17.02.2016 with the right for an extension of derogations up to 3 year (17.02.2019)

Non- interconnected autonomous power systems (islands)	Generation/oil (MWh)	RES Generation* (MWh)	% RES	Peak (MW)
St Eustratios	1.096	0	0,00%	0,307
Agathonisi	749	0	0,00%	0,196
Amorgos	10.069	482	4,57%	3,150
Anafi	1.277	0	0,00%	0,590
Antikithera	255	0	0,00%	0,108
Arkie	371	0	0,00%	0,144
Astepalaia	6.856	574	7,72%	2,210
Gavdos	474	0	0,00%	0,116
Donoussa	841	0	0,00%	0,355
Erikoussa	832	0	0,00%	0,345
Thira	164.060	462	0,28%	42,800
Ikaria	27.129	3.307	10,86%	6,700
Karpathos	37.799	4.541	10,73%	11,300
Kythnos	9.005	403	4,28%	2,980
Kos-Kalymnos	368.521	49.943	11,93%	94,500
Lesbos	297.670	48.928	14,12%	67,420
Lemnos	59.831	7.799	11,53%	14,700
Megisti	3.479	0	0,00%	0,910
Melos	47.642	7.659	13,85%	12,280
Mykonos	135.604	4.544	3,24%	41,300
Othonei	601	0	0,00%	0,262
Paros	217.466	40.080	15,56%	68,200
Patmos	17.477	2.587	12,89%	5,900
Samos	138.050	27.596	16,66%	29,600
Serifos	8.202	173	2,06%	3,420
Sifnos	17.984	345	1,88%	6,220
Skeros	15.663	472	2,93%	4,650
Semi	15.175	279	1,81%	3,840
Seiros	93.021	6.567	6,59%	23,700
Chios	205.833	26.050	11,23%	46,800
Rhodos	814.488	126.336	13,43%	200,000
Crete	2.975.755	699.435	19,03%	627,300
Total	5.693.271	1.058.561	15,68%	

Table 37 Non-interconnected autonomous power systems (islands) - Annual Electricity Consumption (Demand) 2010 – 2016 (MWh)								
Non-interconnected islands	**2010**	**2011**	**2012**	**2013**	**2013**	**2014**	**2015**	**2016**
St Eustrations	1.074	1.058	1.066	1.102	1.075	1.115	1.118	1.096
Agathonisi	529	522	542	599	642	650	702	749
Amorgos	9.806	9.816	9.633	9.354	9.129	9.334	9.865	10.551
Anafe	1.135	1.110	1.137	1.199	1.179	1.223	1.259	1.277
Antikithyra	247	228	238	216	241	243	261	255
Astepalaia	6.741	6.997	7.022	7.089	6.670	6.599	6.772	7.430
Donoussa	635	676	717	667	690	721	810	841
HEreikousa	711	710	664	746	746	697	795	832
Thera	119.517	117.957	120.057	120.817	120.199	135.772	152.375	164.522
Ikaria	30.189	28.845	29.096	28.977	27.613	27.423	28.658	30.436
Karpathos	38.590	37.829	38.784	38.988	36.931	36.928	37.966	42.339
Kythnos	8.382	8.309	8.719	8.672	7.991	8.240	8.607	9.408
Kos Kalemnos	357.626	351.959	361.514	361.681	352.984	351.942	367.337	418.464
Lesvos	312.157	308.454	307.864	300.822	288.230	285.542	296.582	346.598
Lemnos	65.823	62.710	61.795	61.743	59.672	58.486	60.244	67.629
Megisti	2.598	2.751	2.973	3.126	3.005	3.152	3.207	3.479
Melos	42.697	45.819	48.272	49.952	45.402	47.885	49.834	55.301
Mykonos	113.702	115.071	113.615	113.027	112.978	125.916	130.123	140.149
Othonoi	742	674	709	688	632	634	634	601
Paros	211.637	208.206	207.254	203.622	194.740	203.727	212.569	257.546
Patmos	16.605	16.738	17.825	17.475	17.020	17.019	17.788	20.064
Samos	159.581	151.017	150.604	146.503	137.315	136.178	138.186	165.646
Serifos	7.887	8.162	8.299	8.153	7.654	8.178	8.358	8.374
Sifnos	17.825	17.966	17.905	17.364	16.521	17.047	17.617	18.329
Skeros	16.072	16.150	15.698	15.549	14.782	15.073	15.955	16.135
Semei	12.938	15.054	15.031	15.275	14.662	14.132	14.649	15.454
Seros	111.624	107.270	104.608	103.443	95.302	95.227	95.202	99.587
Chios	217.348	214.449	215.739	212.476	200.042	196.993	202.519	231.884
Rhodos	763.567	764.401	780.413	790.593	760.658	760.187	791.768	940.823
Crete	2.988.286	3.014.392	2.945.881	2.944.351	2.825.132	2.866.699	2.898.169	3.675.190
Note: most of the 32 autonomous power systems include more than one island (micro islands)								

The island of Crete opened its market to alternative electricity (conventional fuel) generators, in June 2016. By the end of the year 2016, 7 alternative suppliers had been activated in the local market with electricity supply shares moving from 0,1691% and 1,9% up to 6,6% of the total electricity supply of the island.

The Openness of the market of the second largest non-interconnected island (Rhodes) and the openness of the other islands markets depends on: a) the progress will be achieved by the implementation of the network supply code, b) the infrastructure development based on the annual development plan of DSO (DEDDIE S.A.) for the non-interconnected islands, all of which must be approved by RAE.

3.4.3 Other Regulatory actions in NIIs.

- Evaluating the first Study of the Committee for the alternative ways of electricity supply to the non- interconnected islands. RAE with the Decision 469/2015, proceeded to the formation of the Committee for the Study of the alternative ways (and most efficient way) for electricity supply to the non - interconnected islands. The Committee submitted its First Study to RAE, in March 2016. The study examines alternatives for electricity supply to the NIIs from the technical and the economic perspectives. The development of additional studies and reports regarding; the needed software in NIIs, data monitoring and analysis techniques, the managing flows and congestions in NIIs decided by RAE in 2016 (Decision no 147/2016).

- Evaluating and approving the Methodology for the calculation of the Financial Guarantees of the Generators on the non - interconnected islands to the DSO 47/2016, 46/2016 and 238/2016.

- Evaluating and approving the Methodology for the calculation of the estimated energy consumption, generation charges and shares of generators in total supply (Load System) 46/2016.

- Evaluating the new Emergency Action Plan of DSO (every 5 years), approved by RAE.

- Evaluating the new types of the standard contracts of DSO with the local generators. In September 2016, based on the network code of the non -interconnected islands, articles 89 and 237, the Distributed system operator (DSO) submitted the types of standard contracts for electricity generators (HV, MV, LV, electricity generation classified technologies) to RAE. Decision of RAE in 2017.

- Monitoring DSO's Methodology for managing the Account for Utilities' Social Services (YKΩ) at the Non-interconnected islands. On 25th November 2016, RAE invited the DSO to give "him" instructions regarding the Monthly and annual market (price) clearing and settlement procedures that the DSO must follow, unremittingly.

3.5 RES

3.5.1 RES Installed generation capacity.

RES installed generation capacity in the end of 2016 was 5.255MW, recording an annual increase of 5,8% compared to the year 2015 (4.970MW). The annual increase of the installed generation capacity of RES was lower in the period 2014 – 2015, only 2,7% (from 4841MW in 2014 to 4970MW in 2015). We recall that the total installed electricity generation capacity in the interconnected system (i.e. including all the plants using conventional fuels and the generation plants of RES) was 17.197 MW in the end of 2016. Table 38, illustrates the annual change in the RES installed generation capacity per technology for the period 2014 -2016.

Table 38: RES in Greece (excluding large Hydro>10MW)					
RES Technology	**Installed capacity in 2014 (MW)**	**Installed Capacity in 2015 (MW)**	**Installed Capacity in 2016 (MW)**	**% change 2014-2015**	**% Change 2015-2016**
Wind	1.978	2089	2370	5,60%	13,55
PV	2221	2229	2229	0,40%	0,00%
PV on roof	375	376	375	0,20%	-0,20%
Hydro Small	220	224	223	1,80%	-0,40%
Biomass - Biogas	47	52	58	10,06%	11,50%
Total	4841	4970	5255	2,60%	5,70%

3.5.2 RES electricity generation in 2016.

The Greek electricity generation mix has a diversified structure considering that lignite units generated 14.898 GWh, natural gas units generated 12.680 GWh, RES generated 10.191GWh, Hydro generated 4.843 GWh and import flows supplied almost 10.966 GWh, in 2016. We underline that RES including Hydro for the first time, were the largest generators of the Greek power generation mix in 2016 generating 15.043GWh.

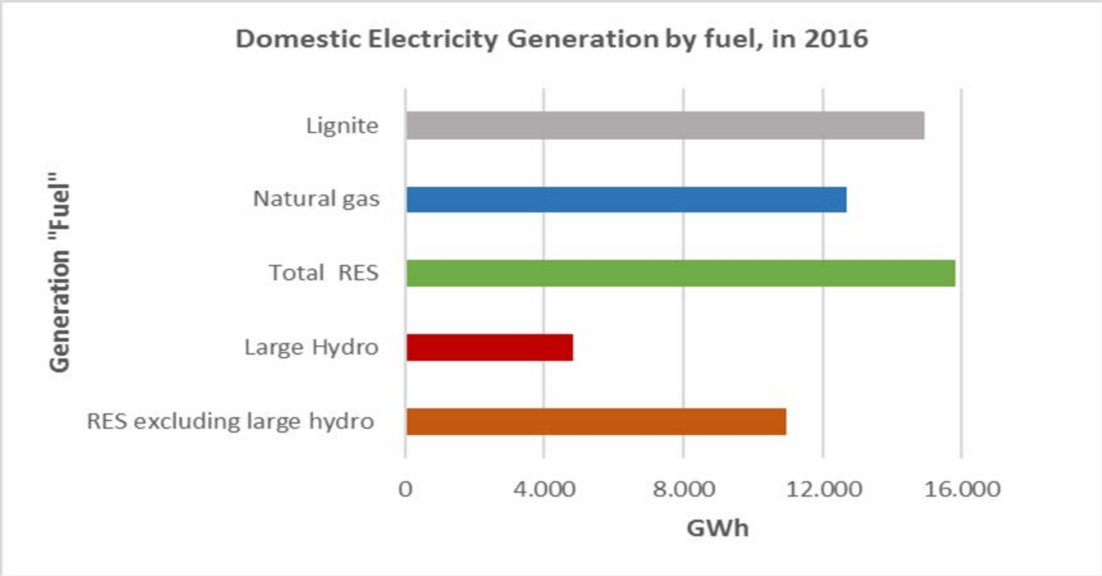


Figure 13. Domestic Electricity Generation by Fuel, in 2016

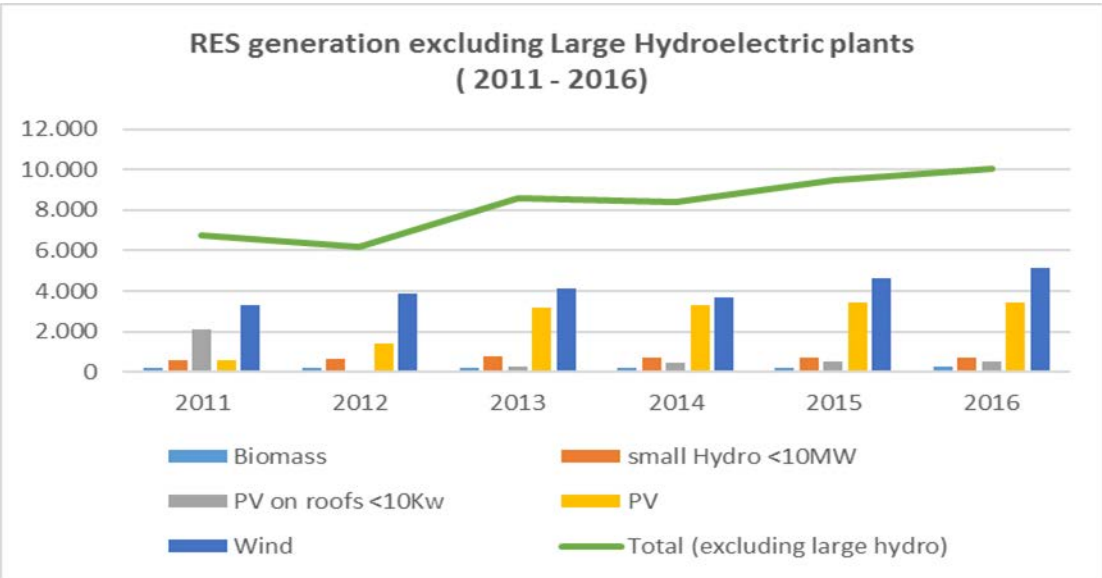


Figure 14. RES Generation excluding Large Hydroelectric plants

Table 39 RES Generation excluding large hydroelectric plants (2011-2016) GWh.						
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Biomass	199	197	210	207	222	253
small Hydro <10MW	581	670	772	701	707	722
PV on roofs <10Kw	2.089	56	279	480	507	494
PV	557	1.415	3.168	3.322	3.409	3.418
Wind	3.315	3.850	4.139	3.689	4.621	5.146
Total (excluding large hydro)	6.741	6.188	8.568	8.399	9.466	10.033*
The official number given by ADMIE for the year 2016 is 10.191GWh						

3.5.3 RES and the electricity Market.

There is currently no intra-day electricity market in Greece (a mean for the development of RES market). RAE in cooperation with the Ministry of Energy, the TSO and DSO are currently working on the development of the new electricity market model with the aim of integrating the Greek market into the European electricity market. The participation of RES and HECHP installations in the electricity market continue to take place during the transitional period (2017-2020) only through the day ahead market, where RES generation participate with zero price offers. Greece Is planning to implement a new electricity model. As currently there is no a liquid intra -day market in Greece, during the transitional period up to the implementation of the new market model, beneficiaries will not be subject to standard balancing their trading position obligations.

3.5.4 RES projects' licensing.

The Ministry of Energy in cooperation with RAE amended the current legislation of RES. A new support scheme for renewable energy resources (RES) and high efficiency combined heat and power (HECHP) installations published on 9th August 2016. The national Legal basis is Law 4414/2016 on a new support scheme for RES and HECHP. The support scheme intends to incentivize electricity production from RES to contribute to the achievement of the target set by Directive 2009/28/EU on the promotion of the use of energy from renewable sources at 20% share of energy from RES sources on the EU overall gross energy consumption in 2020. Directive 2009/28/EU, set this target for Greece, based on GDP/capita, energy consumption and other indicators, at 18% share of RES on Greece's overall consumption in 2020.Based on the latest data Greece's RES share on total final gross energy consumption was 15,32% in 2014, with electricity from renewable sources (RES-e) representing almost 24% of the total electricity generation. Significant new investment still required to reach the above mention achievement national RES target. It is estimates that, in terms of electricity generation capacity, the current gap which must be covered by the year 2020, if nothing change, is currently (moving) between 2.000MW and 2.500MW.

Table 40: Projects with a license/permission of generation (non- operational) approved by RAE, end of year 2016.		
Technology	No of Licenses	Capacity Power (MW)
Wind	1128	23.717,02
PV	908	4.184,07
Hydro (small)	436	976,23
Geo	1	8
Biomass	87	381,61
Solar	82	442,2
Hybrid	20	345,05
Co-generation (electricity & heat)	66	416,92
Total	2.728	30.471,1

Technology	Table 41 Number of RES applications and number of generation licenses							
	2015				2016			
	Number of Applications for generation license		Decisions/ Permissions approved by RAE		Number of Applications for generation license		Decisions/ Permissions approved by RAE	
	No	Power Capacity (MW)	No	Power Capacity (MW)	No	Power Capacity (MW)	No	Power Capacity (MW)
Wind	20	183,70	25	467,00	79	429,6	15	178,6
P/V	2 *	3,66	13	185,80	0	0	3	16,89
Hydro small	6	8,31	6	5,30	33	79,52	5	7,62
Biomass	18	85,50	3	31,19	10	27	1	1,5
Cogeneration electricity& heat	1	4	2	32,00	1	4,54	0	0
Solar	0	0	0	0	0	0	0	0
Hybrid	1	1,80	0	0	56	294,31	1	0,96
(Tele) heating	1	9,80	0	0	0	0	0	0
Total	49	296,77	49	721,30	179	834,79	25	205,57

The main change in the new RES support financial scheme is the abolition of the Feed in Tariff financial support mechanism for new RES projects, larger than 5MW and the adoption of the new mechanism of Feed in Premium. In addition, the new legislation amended ETMEAR (RES levy) and the structure of the RES financial support account to ensure that the debt in the RES account is eliminated over a 12-months forward looking horizon (not later than June 2017); the account will be kept annually in balance onwards. The initial amendment on renewable energy incentives had been approved on 4 August 2016 (Law 4414/2016). An amendment which brings several points in line with the milestone has been legislated on 6 October 2016. It also foresees elimination of the debt in the RES account by December 2017, which is longer than the originally envisaged timeframe, but includes a corrective mechanism to prevent further or persisting imbalances of the RES account during this timeframe. Moreover, regular provision of data on the RES account has been agreed with the Greek authorities.

3.5.5 RES new Financial Support Scheme

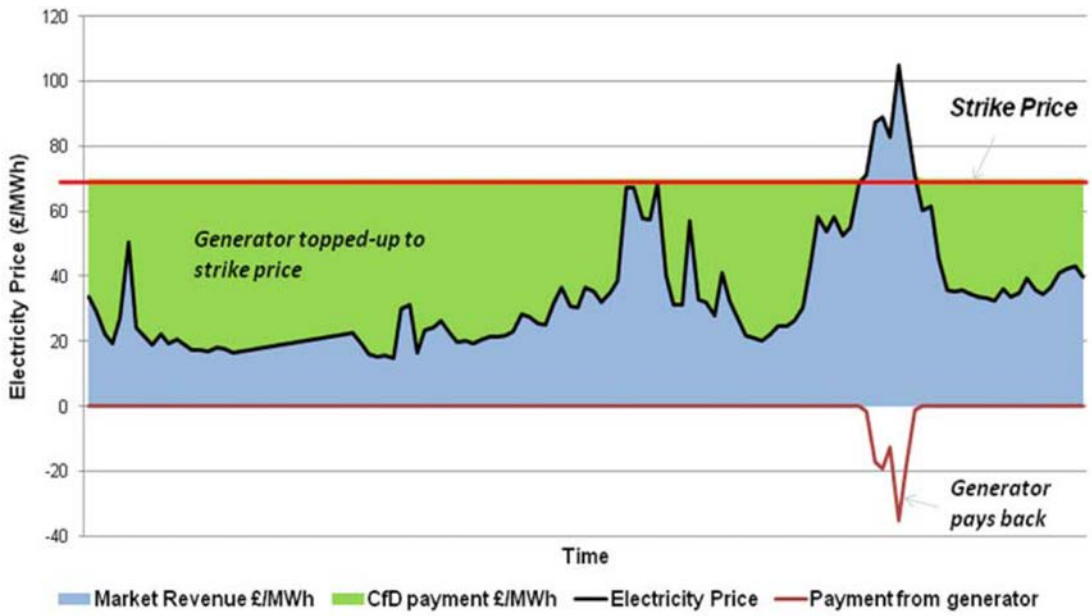
The new financial support scheme was approved by the European Commission, in November 2016. The main objective of the new RES support mechanism is to achieve an efficient integration of renewables' generation into the electricity market. The fields of energy and environment were included in the EU Guidelines on State Aid, notably, the "Guidelines on State Aid for environmental protection and energy 2014-2020" (EEAG), issued on 9th April 2014, and applicable from 1st July 2014. The EEAG clarify the assessment rules of State Aid cases, regarding compatibility with internal market (Art. 107[2&3] of the EU Treaty). Specifically, the Guidelines spell out the conditions to be met, inter alia by the support schemes to ensure compatibility with the rules on State Aid, with a view to strengthen the internal market, promote more effectiveness in public spending, introduce a greater scrutiny of the incentive effects and limit the aid to the minimum necessary, to avoid the potential negative effects of the aid on competition in the internal market

The new scheme is designed to support revenue based on cost reflective, market-based Operating Aid, which will ensure that both phenomena of *over-compensation* and *under-compensation* of power production from RES and HECHP are minimized. A technology-specific **Sliding Scale Feed in Premium** (FiP) will be added as a premium, to the revenues received by the RES producers, through their participation in the wholesale electricity market, for the relevant Operating Aid to reach an acceptable level of support, measured against a Reference Tariff (RT) per renewable energy technology. The RTs will be initially administratively determined for all technologies and from 2017 will be set through competitive bidding for most producers, on a project-by-project basis.

As from 1 January 2016, all RES and HECHP power plants that commence (commissioning or commercial) operation in the interconnected system, participate in the electricity market, and are included in a support mechanism in the form of *Operating Aid* based on a *Differential Compensation Price* (*Sliding Premium*), for the power they generate and is absorbed by the interconnected system. The *Sliding Premium* is expressed in a monetary value per measurement unit of the generated power that is injected, and which is cleared, billed and its transactions are settled monthly, in accordance with Article 5 of the Law.

The *Sliding Premium* shall be calculated monthly, as the difference between on the one hand, the **RT** applicable for the *"Contracts of Difference"* (Feed in Premium Contracts FiPC), and on the other hand, the **Special Market Price for Renewables (SMPRES)** for the specific RES, or HECHP technology: **FiP = RT – SMPRES**. The FiPCs are signed between the producer and the Hellenic Electricity Market Operator (known by its Greek initials as "LAGIE"), for the power generated from RES and HECHP plants under Article 10 of the Law, and which is defined per RES and HECHP power plant technology and category, or per RES or HECHP power plant, in case this results from the conduct of competitive processes, in Euro per megawatt hour (€/MWh). The SMPRES will be calculated differently for *intermittent* (i.e. wind power, solar PV and small hydro power plants) and *non-intermittent* (i.e. biomass, biogas, geothermal, solar thermal including storage facilities, and highly efficient co-generation of heat and power plants) renewable energy projects. The type and contents of the FiPC, as well as the conclusion procedure, will be set out in a Ministerial Decision on the proposal of LAGIE and the opinion of the Greek Regulatory Authority for Energy. The duration of the Operating Aid is 20 years for all RES and HECHP technologies, apart from small rooftop PV installations up to 10 kW and CSP installations for which the duration is set to 25 years.

Figure 15: The new Support Scheme in a snapshot.



The RTs for all renewable energy technologies and categories of projects stipulated in the new Law, other than solar PV with an installed capacity more than 500kW, are set administratively for 2016 (remaining however, applicable for the term of the relevant FiP or FiT Contract signed in 2016).

Table 42. Reference Tariffs of Law 4412/2016, Table 1 of Article 4.1(b)		
Renewable technologies and project categories	**RT (€/MWh)**	**Project IRR**
Onshore wind parks in the Interconnected System	98	9%t
Onshore wind parks in the Non-Interconnected Islands	98	9%
Small hydropower ≤ 3MW	100	9%
Small hydropower > 3MW and ≤ 15MW	97	9%
Solar PV < 0.5MW [*Roof-top solar PV installations are regulated by special legislation and hence excluded from the present briefing.*]	1,1 * wholesale electricity market price of the previous calendar year	-
Solar PV ≥ 0.5MW	Competitive bidding	-
Biomass (or bioliquids) from thermal processing ≤ 1MW (excluding the biodegradable fraction of urban waste)	184	9%
Biomass (or bioliquids) through gasification ≤ 1MW (excluding the biodegradable fraction of urban waste)	193	9%
Biomass (or bioliquids) from thermal processing (including gasification) > 1MW and ≤ 5MW (excluding the biodegradable fraction of urban waste)	162	9%
Biomass (or bioliquids) from thermal processing (including gasification) > 5 MW (excluding the biodegradable fraction of urban waste)	140	9%
Landfill gas and biogas from anaerobic digestion of the biodegradable fraction of urban waste ≤ 2MW	129	9%
Landfill gas and biogas from anaerobic digestion of the biodegradable fraction of urban waste > 2MW	106	9%
Biogas released from anaerobic digestion of biomass (energy crops, rural waste and residues, etc.) ≤ 3MW	225	10%
Biogas released from anaerobic digestion of biomass (energy crops, rural waste and residues, etc.) > 3MW	204	9%
Solar thermal without storage system (unless bioliquids are used, in which case see above)	257	9%
Solar thermal with storage system (minimum two hours) (unless bioliquids are used, in which case see above)	278	9%
Geothermal power ≤ 5MW	139	10%
Geothermal power > 5MW	108	10%
Other renewable energy technologies	90	10%

3.5.6 RES Capacity generation auction. A Pilot Project.

With RAE's decision 417/2016, the Regulator organized and operated its first auction for offers of new capacity generation from PVs as a pilot project, in December 2016. The auction took place on 12th December 2016. The Regulator classified two categories of PVs offers for two type of auctions. The first auction was for the category of PVs units < 1MW and the second auction for the category of PVs > 1MW. The total offered quantity for both categories of PVs was defined at the maximum level of 40MW (i.e., 5MW for the first type and 35MW for the second type of auction). According to the rules of the auction, the maximum new capacity generation offer from every auctioneer could not be more than 10MW. The Reference price for the first type of auction (<1MW) was 104€/MWh and for the second type of auction (>1MW) was 94€/MWh. The auction time for both types of auction was not more than 30 minutes. Both auctions were successful the first type of auction approved offers of 4,79MW generation capacity at the average (weighted) price of 98,78€/MWh, while the second type of auction approved offers of 35,1 MW new generation capacity at the average (weighted price) of 83,3MWh.

3.5.7 RES Financing

Several instruments are in place to support the financing of RES, including a revenue from the operation of the day ahead market, a revenue from the market clearing and settlement procedures of the day ahead market, a revenue equal to the average variable cost of conventional Generation units (this is important especially for NIIS), a revenue from the energy cost, a revenue for CO2 emission rights and Levy on CO2 emission of conventional generation units. In 2016 RES account appeared an estimated deficit of 238,48 million Euro. However, in 2017 RAE with its decision on 22 December 2016 (no 621/2017) proceeded to amendments on the methodology of the calculation of RES Levy. More specific, RAE reallocated the cost of RES Levy financing among the different categories of consumers (HV, MV, LV). This reallocation is expected to offer to RES' account a surplus of 71,81 million Euro in the end of the year 2017.

Table 43 RES' Financing Account	2016	2017
Total Revenue (in million euros)	1623,63	2167,01
Day Ahead Market	361,56	440,82
Market Clearing and Settlements	8,88	-
Average Variable Cost of Generation	36,13	33,26
Average Variable cost of generation (NIIs)	107,38	135,56
RES Levy (ETMEAR)	953,24	976,04
Energy Charge (Suppliers)	31,65	371,92
Levy on CO2	29,4	31,9
CO2 emmission Rights	89,59	169,51
Other (licences fee)	5,8	8
Total Expenditure (in million euros) (November 2016)	-1799,87	-1856,71
For the rest of the year 2016 (estimated)	-238,48	71,81

According to the Law 4001/2011 article 143 RAE has the authority to monitor RES accounts and to proceed to amendments on the methodology of the calculation of RES Levy (ETMEAR). In December 2016, RAE taking into consideration the reported RES' account deficits of the previous years, decided to reallocate the cost of RES Levy among the different categories of consumers (RAE's Decision no 621/2016). The table below reports the new RES' charges/levy by a consumer category, for the year 2017 based on RAE's decision 621/2016.

Table 44 Classification of Customers	RES Levy in 2017 (Charge per unit €/MWh)
HV	2,51
MV >13GWh	2,51
MV <13GWh	9,76
MV Agriculture	9,71
LV Agriculture	10,47
Households LV	24,77
Other LV	27,79

3.6 Consumer Protection

3.6.1 Compliance with Annex 1 of Directive 2009/72/EC

Articles 37, paragraph 1, letter n), and article 41, paragraph 1, letter o), of Directives 2009/72/EC require that the regulator, if necessary in collaboration with other Authorities, guarantee that their consumer protection measures, including those in Annex 1, are effective and applied. Table 5.1 illustrates the implementation status in Greece of the measures set out in Annex 1.

State of implementation of measures set out in Annex 1 (Directive 2009/72/EC)

PARAGRAPH 1	LETT.	IMPLEMENTATION STATUS
Customers have a right to a contract with their electricity supplier that specifies a series of aspects.	a)	This obligation is covered by the Electricity Supply Code, which sets out the information that must be provided before the conclusion of a contract and the main clauses that must be included in a contract. The same Code also requires that the customer must be provided with the contract in a durable medium. With regards to the services and the service quality levels offered, they must be available to consumers through the Services Leaflet which is published on the Supplier's site. Currently compensation schemes which apply if contracted service quality levels are not met, are not offered by Suppliers.
Customers are given adequate notice of any intention to modify contractual conditions and they are informed about their right of withdrawal when the notice is given	b)	The Electricity Supply Code requires that customers must receive 60 days of notice prior to the application of the modifications to contractual terms, except for price modifications where customers can be informed with the next bill after the price change. In any case, customers have the right to withdraw from the contract at no cost if they do not agree with the new terms.
Customers must receive transparent information on applicable prices and tariffs and on standard terms and conditions in respect of access to and use of electricity services.	c)	The Electricity Supply Code stipulates that contracts must contain a section which clearly summarizes the costs borne by customers for the supply of electricity.

Customers are offered a wide choice of payment methods.	d)	This obligation is derived from the Electricity Supply Code with the additional term that at least one payment method offered by each Supplier must be cost free
General terms and conditions shall be fair and transparent, and given in clear, comprehensible language. Customers shall be protected against unfair or misleading selling methods	d)	The Electricity Supply Code contains the minimum "Principles of information and contact with clients" that cover all the required obligations. Suppliers are obliged to introduce a Code of Contact based on at least the above referred principles.
Customers are not charged for changing supplier.	e)	Supplier switching is free of charge according to the Electricity Supply Code.
Consumers benefit from transparent, simple and inexpensive procedures for dealing with their complaints.	f)	The Electricity Supply Code stipulates that Suppliers must operate a Consumer service department that handles customer complaints according to at least the minimum "Standards of complaints handling" included as a separate section of the Code. Written complaints / enquires must receive a first or final response within 10 working days.
Consumers benefit from information about their rights regarding universal service (electricity customers) of their right to be supplied at reasonable prices	g)	The relevant information for consumers can be found on the Authority's website (www.rae.gr)
Consumers can have at their disposal their consumption data and shall be able to allow any registered supply undertaking to access, by explicit agreement and free of charge, their metering data	h)	Consumers are adequately informed of actual consumption, quarterly or every four months through their bills. In addition an application form is available at their Supplier's site and/or customer service centers, to request for historical consumption data.
Consumers receive a final closure account following any change of supplier, no later than six months after the change of supplier has taken place.	j)	Energy Suppliers are obliged to issue a final closure account, within 6 weeks after the contract termination/change of supplier.

PARAGRAPH 2		
Member States shall ensure the implementation of intelligent metering systems that shall assist **the active participation of consumers in the electricity and natural gas supply markets**		In the electricity sector the timeframe for the roll-out of smart meters is set by Law no. 4001/2011 for the replacement of at least 80% of old meters by 2020.

3.6.2 Ensuring access to consumption data

Regulation Decision no. GOV B’ 82/27.1.2006 (“Guide for management and periodic settlement of DSO measurements”) requires that the DSO must, gather consumption measurements at least every 6 months. In practice the frequency of recording consumption data is every four months. Consequently, small consumers are informed about their actual consumption at least every four months through their Suppliers bill. Furthermore, consumers can have access to historical consumption data through a simple application registered to their Supplier.

3.6.3 Consumer empowerment

One of the main priorities of the Authority in 2014 was consumer’s protection regarding easy access to significant information on energy developments and the upgrading of the quality of electricity distribution services.

3.6.4 Information

To strengthen the consumer’s position in the retail market, in 2014, the Authority, in cooperation with the competent departments of the Ministry of Administrative Reform and E-Governance prepared and distributed to consumers 228.000 pieces of three different thematic brochures through all the “Single Point of Contact” centers located in Attica that represent at least 40% of total population. The aim was to inform energy consumers on their rights related to electricity Supplier switching, out of court dispute resolution and the low electricity tariff for vulnerable consumers.

3.6.5 Quality of DSO Services

Another key direction of RAE was related to the improvement of the customer services of the electricity DSO. After at least one year of negotiation the DSO’s program of guaranteed distribution services with individually guaranteed standards was redesigned, upgraded and came into force in April 2014, by adapting the following main modifications:

1. In addition to the ten services already included in the old program, the following four new guaranteed services were introduced:
   1) The construction of a new electricity supply that requires simple network extension, within working 40 days.
   2) Electricity interruptions for Medium voltage consumers due to network failure or planned interruptions are restored within a maximum of 12 hours.
   3) Meter inspection after a client's request is concluded within working 20 days.
   4) Written consumer complaints about the quality of voltage, are replied within working 30 days.
2. The penalty of 15 € for exceeding the time limits of services, shall be credited to consumers automatically through their bills, without the previous requirement of submitting a written application to the DSO. In the case of MT clients, the penalty for planned interruptions recovery within 12 hours is 150 €.

Based on the annual data provided by DSO, on the minimum quality requirements for individual users, the Guaranteed Services program was evaluated by the Authority, for 2015:

Table 45: Performance of Guaranteed Services: Consolidated figures, 2009-2015

DSO Guaranteed Services (G.S.) 2009-2015										
Service	Guaranteed level Upgrade		Unit	% of failed cases						
	Up to 2013	2014+		2009	2010	2011	2012	2013	2014	2015
Instrumentation - connection of meter	3	4	Working days	12.23%	11.34%	10.25%	13.58%	12.44%	4.85%	4,24%
Connection offer with network extension	25	20	Working days	5.94%	3.89%	3.93%	4.86%	3.68%	1.17%	0,48%
Reconnection after client's request	2	3	Working days	3.16%	2.89%	3.39%	3.25%	3.47%	1.31%	0,44%
Reconnection after settlement of debt	Same day	2	Working days	1.96%	1.58%	1.58%	1.59%	1.80%	0.55%	0,70%
Intervention for fuses replacement	4	4	Hours	0.75%	1.50%	1.48%	1.56%	1.77%	0.46%	0,55%
Connection offer for simple works connection	15	15	Working days	1.55%	1.68%	2.97%	4.52%	1.35%	0.79%	0,37%
Observance of appointment time	3		Hours	9.46%	5.92%	2.89%	2.05%	1.20%	OUT OF G.S.	OUT OF G.S.
Response to written requests-complaints, that require visit	15	20	Working days	1.66%	1.11%	0.79%	0.60%	0.66%	0.76%	1,54%
Response to written requests-complaints, without visit	10	15	Working days	0.54%	0.26%	0.11%	0.12%	0.64%	0.18%	0,21%
Construction of simple connection	30	30	Working days	0.51%	0.38%	0.53%	0.54%	0.46%	0.36%	1,79%

<u>New</u>: Inspection of meter, after client's request		**20**	**Working days**						**8.26%**	**4,20%**
<u>New:</u> Disconnection after client's request		**3**							**3.43%**	**2,06%**
<u>New</u>: Supply restoration, after network failure/scheduled works, for MV customers		**12**	**Hours**						**3.00%**	**0,22%**
<u>New</u>: Construction of new connection with network extension		**40**	**Working days**						**0.79%**	**1,41%**
<u>New</u>: Response to written complaints on network quality of supply		**30**	**Working days**						**0%**	**0%**
Total No of applications				**807,527**	**808,513**	**880,673**	**912,692**	**848,430**	**728,635**	**651,245**
Total % of failure on guaranteed services				**3.76%**	**3.33%**	**3.22%**	**3.20%**	**3.04%**	**1,67%**	**1,19%**

There is a decreasing trend during 2009 – 2015 on the total percentage of non-performed cases identified by DSO as well as for most of the individual services.

3.6.6 Vulnerable customers and Energy poverty

In 2015, RAE stepped up its activities to combat energy poverty, by taking more targeted measures. In addition to the Social Residential Tariff, that was applied since 01.01.2011 to five (5) categories of vulnerable customers (Families with Low Income, families with 3 children, long and short - term unemployed and people living on medical support) and the law rate Social Solidarity Tariff that was introduce in 2014 to support the need for electricity of certified non-profitable institutions that provide social care services, the following measure were introduced:

1) Consumers with quite low income are entitled to join the Economic Crisis Program which was introduced in 2015 that provides free of charge reconnection of the electricity supply,

free of charge consumption of 300kWh/month, social funding for house rental, for meals and lodging.

The following table 46 presents the number of customers and total electricity consumption of the Residential Social Tariff (2011-2016).

Table 46 Number of customers and total consumption - Residential Social tariff 2011 – 2016.

	Residential Social Tariffs 2011 - 2016		Economic crisis Program	
Year	Number of customers	Total Energy (kWh)	Number of customers	Total Energy (kWh)
2011	247.666	548.006.275		
2012	250.568	404.333.772		
2013	412.883	1.582.503.518		
2014	522.760	1.251.208.124		
2015	608.714	2.236.690.571	70.002	232.886.076
2016	578.311	1.549.216.127	46.562	244.020.079

3.6.7 Handling of consumer complaints

Consumers can submit enquiries and complaints to RAE in writing through personal visit to the offices, by sending an email to info@rae.gr, by post or by fax. They can also contact the central telephone center of the Authority for simple information enquiries. Particularly complex enquiries are sent in written form.

During 2014, RAE also introduced on its site an online form for consumer complaints and enquires which can be filled and automatically sent to RAE together with all necessary attachments.

The total number of consumer reports (complaints and enquiries) submitted to RAE during 2016 was 364, revealing a significant increase, reaching the high levels of 2013. This increase is mainly attributed to disputes mainly between consumers and the Electricity Distribution Network operator about consumption meter violation and a few other issues, as well as invoicing inquires, explanations etc.

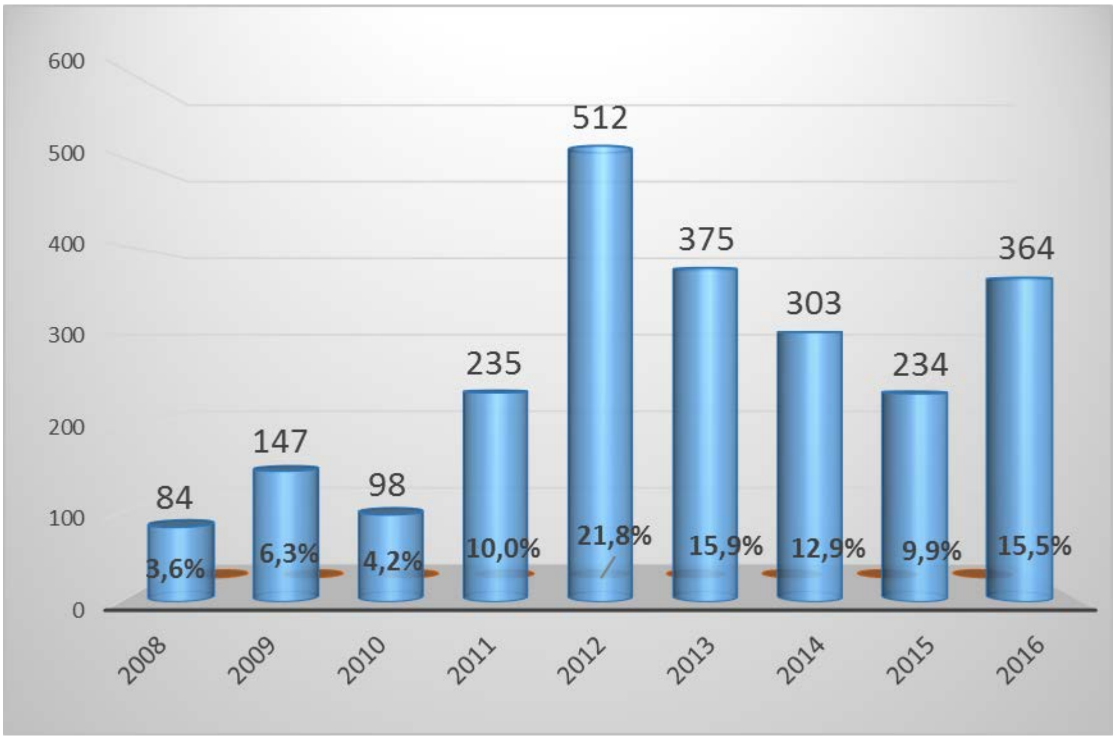


Figure 16. Total Number of consumers' complaints.

In terms of Supply provider issues, consumer reports of 2016 (Fig. 16) were focused primarily on cost and electricity expenses matters, revealing the country's continuing economic crisis. In particularly consumers seem to be more cautious before paying their invoices. Such consumer reports included:

1. Invoicing / billing (79.6%),
2. Prices and rates (29.9%), that is related to the following issues: a) insufficient information on the calculation method of charges, or/and the unit price, disputed calculation of regulated charges

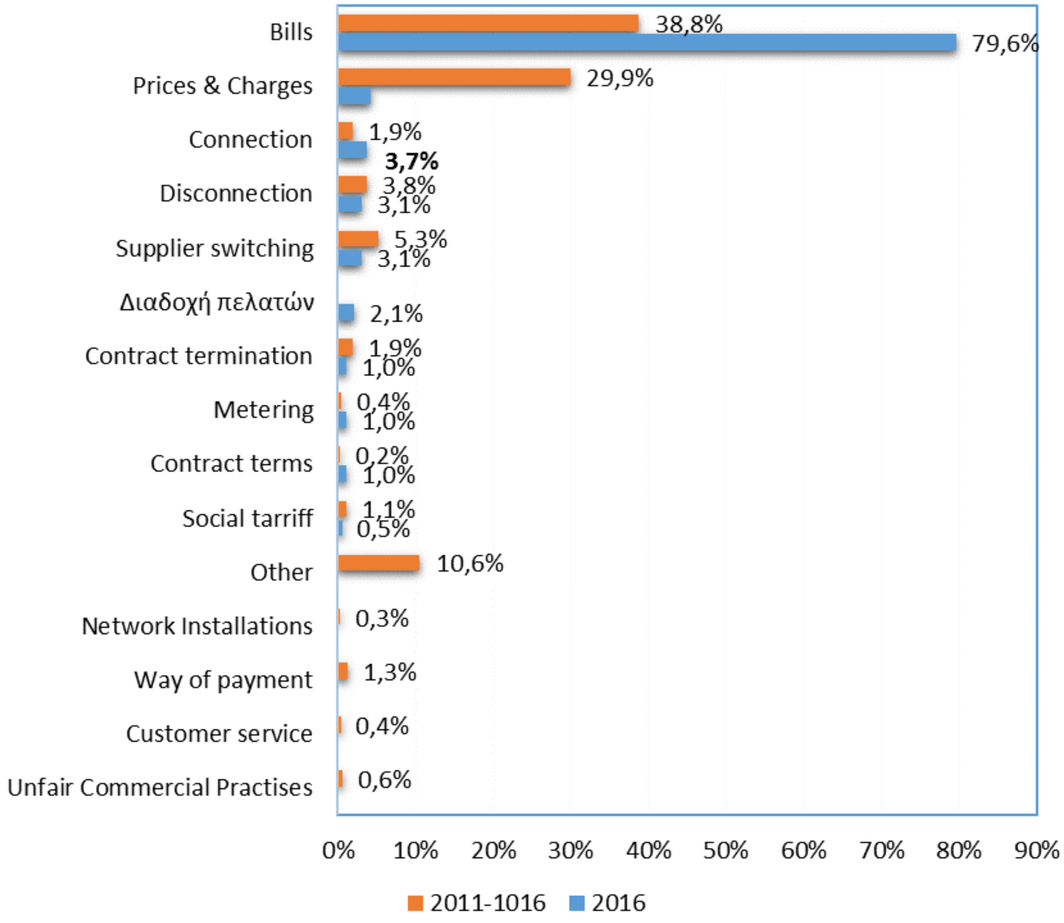


Figure 17: Supply Complaints by thematic category (base:2011-16=1400, 2016=191)

In terms of Distribution Network issues, consumer reports of 2016 amounted to 149 cases are presented in comparison to the corresponding consumer reports of years 2011 to 2016 in Fig. 18 below. There is an at least 10,3% increase of DSO reports, reaching a rate of 32.1% in 2015 out of total consumer reports, from 21.8% of the previous year and a further increase of 9% of DSO reports from 2015 to 2016, reaching a rate of 40.9% in 2016. The major issue in 2016 was the disputes on electricity meter meter violation which reveals the impact of the long standing economic crisis.

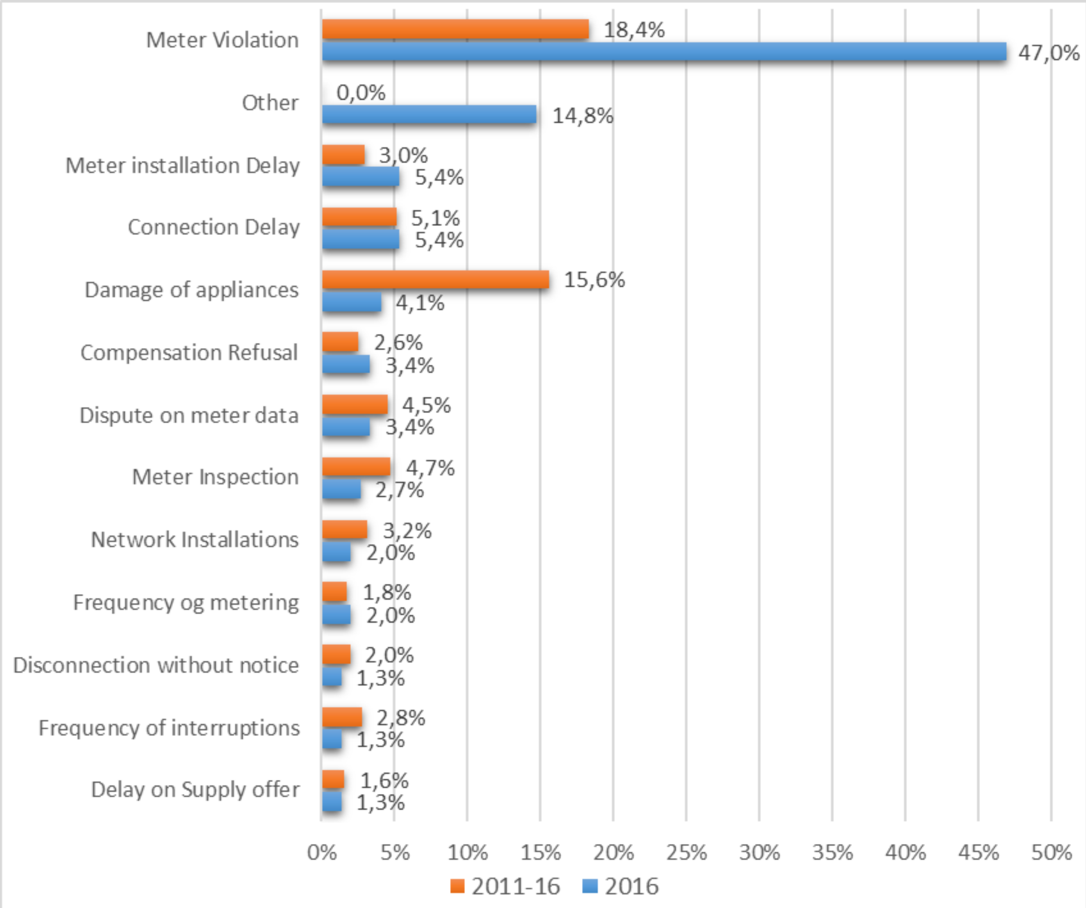


Figure.18. DSO Complaints by thematic category (base:2011-16=506, 2016=149)

3.6.8 Dispute Settlement

The Hellenic Consumer's Ombudsman is legally responsible authority for dispute settlement between consumers and companies including energy service providers.

As a mediator, the Hellenic Consumer's Ombudsman draws conclusions, makes recommendations and/or proposals to the companies after following a hearing process, but is not authorized to impose sanctions. However, if any of the involved parties do not accept the authority's recommendation, the Consumer Ombudsman may disclose the case in public.

In addition, RAE handles all complaints addressed in written to the Authority, investigates the cases and tries to settle the disputes or makes recommendations to the companies or draws regulations and/or imposes sanctions to the companies if a significant number of consumers is affected. Some of the most characteristic cases handled and resolved by the RAE during 2016 follow:

Procedures for the evaluation of the submitted applications of the new consumers to the Retailers for electricity supply and the supply contracts' provisions for new customers.

In response to a consumer's report to the Regulator, RAE confirmed that a specific Retailer do no follow the procedures of the Network Distribution Code and especially the procedures for signing an electricity supply contract between the retailer and the customer. According to the Code's provisions, the retailer has to ensure that the contracting party (the customer) has the competence or the legal authority to sign a contract. RAE recommended to the retailer to fully apply the provisions of the Code regarding the procedures for the evaluation of the customers' applications for electricity supply.

Dispute between customers and the Distribution System operators about the calculation of the consumed quantity of electricity due to a problem of the metering system.

In response to a group of consumers report to the Regulator regarding the estimated by the DSO, consumed quantity of electricity by the group of customers, RAE monitoring the case's facts and taking into consideration all the arguments of the customers, called the Distribution system operator to reexamine with objectivity and fair justice the arguments of the customers to proceed to a fair charge of the consumed quantity of electricity.

Monitoring the advertising policies of the retailers and the full implementation of the relevant provisions of the Retail Supply Code to customers.

Taking into consideration the intensive competition among the retailers and the applied advertising policies of the retailers to attract more customers and to gain higher shares in the retail market, RAE took the initiative to monitor the advertising policies of the retailers in respect to the Distribution Code of Electricity Supply to Customers. RAE will examine whether the advertising policies of the retailers meet especially the criteria/provisions of transparency, simplicity, freedom of switching and of fair pricing. The results of the monitoring and of the investigation will be finalized and announced in 2017.

The Methodology for the calculation of the Social Utilities' Services Tariff based on the metering method of the Distribution System operator (DEDDIE).

In response to consumers' reports regarding their objection to the methodology of the calculation of the Social Utilities' Services Tariff (YKΩ), especially in cases of switching supplier or/and reporting the consumed quantity of electricity by the customers, RAE confirmed that the method for the calculation of SUST (YKΩ) in many cases is false and lead to customers' overcharging. Therefore, RAE recommended to the Retailers any charges to their customers to be based on customers' four months clearing account and not on Retailers' estimations or customers' reporting. RAE will proceed to the full implementation of all the necessary measures by the side of the Distribution of System operator and the Retailers to have a fair methodology of calculation of SUST.

4. Regulation and Performance of the Natural Gas Market

4.1 Network Regulation

4.1.1 Unbundling

A) TSO Unbundling

The TSO of the National Natural Gas System (NNGS) in Greece was established as a "société anonyme" under the name of "DESFA S.A." in February 2007. DESFA S.A. is a 100% subsidiary of DEPA S.A., the incumbent and vertically-integrated gas company in Greece. DESFA S.A. is the owner and operator of the national network gas system (NNGS), which is comprised of the main high pressure pipeline and its branches, as well as the LNG Terminal at the Revithoussa island, and is a certified ITO under the unbundling rules of the Third Energy Package. DESFA S.A. has exclusive rights for the operation, maintenance, development and exploitation of the NNGS and is currently the only gas transmission system operator in the country.

In September 2011, for first time, RAE published on its website detailed guidelines regarding the certification procedure and the relevant data requirements for all the unbundling models, provided for in the Third Energy Package, and for both the electricity and gas TSOs. The Energy Law 4001/2011 that entered into force in August 2011 and transposed the Third Energy Package into the national legislation, provided only for ownership unbundling of DESFA S.A. from DEPA S.A. However, the above law was subsequently amended in December 2011, by a Governmental Legislative Act, to allow for either model, Ownership Unbundling or ITO, to be followed in the case of the Vertical Integrated Undertaking (VIU), i.e. DESFA S.A. under the ownership of DEPA S.A. This amendment was introduced in view of the government's intent to privatize the natural gas incumbent and to allow potential investors to express their interest in acquiring one or both above companies. A second amendment of Law 4001/2011, enacted by two consecutive Government Legislative Acts, took place in November of 2012, to introduce more specific provisions on the implementation of either the Ownership Unbundling or the ITO model, to accommodate the DEPA/DESFA S.A. privatization process (tender). Consequently, the TSO's certification procedure started only at the end of December 2012, when DESFA S.A. applied to RAE to be certified as an Independent Transmission System Operator (ITO model).

However, before the completion of the DESFA certification procedure under Article 10 of the Gas Directive, and before the notification of the preliminary decision of RAE to the European Commission, significant new developments took place. More specifically, DESFA, under the circumstances specified in Article 11 par. 2 of the Gas Directive and Article 65 par. 2 of Law 4001/2011, informed RAE, in December 2013, on the pending acquisition of 66% of the share capital of the company by the State Oil Company of Azerbaijan (SOCAR), which had emerged as the successful bidder in the international tender process that had taken place for the sale of that share. In this context, DESFA informed RAE that a new request for certification would be submitted to RAE for evaluation under this imminent change of its ownership regime and in relation to its acquisition by a third-country entity. This new certification request was submitted to RAE by DESFA on 29/01/2014.

RAE examined the request to certify DESFA as an ITO under both DEPA, as DESFA's owner at the time, and SOCAR, as DESFA's possible future owner, and within the four months' statutory period from the date of the above notification deadline, issued its draft certification decision on 26/05/2014. This draft certification decision was made per the provisions of articles 9, 10 and 11 of the Gas Directive and Articles 63a, 64 and 65 of Law 4001/2011.

On 4 August 2016, a new published law (Law 4414/2016) identifies the new process of unbundling of the natural gas Transmission System operator (DESFA) from DEPA S.A.

During 2016 the transaction between SOCAR SA and DESFA SA was pending before the Directorate-General for Competition of the European Commission in a Phase II assessment under the EU Merger Regulation. The European Commission's initial market investigation indicated that the merged entity may have the ability and the incentive to hinder competing upstream gas suppliers from accessing the Greek transmission system, to reduce competition on the upstream wholesale gas market in Greece. The merged entity could restrict its competitors' access to the Greek gas transmission network by strategically limiting investments in future expansions of the import capacity including an expansion of the LNG Terminal and an interconnection between TAP and DESFA's network. In addition, the merged entity could restrict inflows of gas into Greece by managing the gas transmission network in a discriminatory way favoring SOCAR's supplies over its competitors. The preliminary investigation also suggested that SOCAR may have the incentive to shut out competitors from access to the network, because it would be profitable for SOCAR. This could reduce the number of current and potential suppliers and the amount of natural gas in Greece and lead to higher gas prices for clients. Finally, SOCAR S.A. announced its decision to cancel its investment in the Greek TSO in December 2016.

B) DSO Unbundling

The three EPAs; EPA Attiki, EPA Thessaloniki and EPA Thessalia were operating under a regime of exclusive rights for both the activities of distribution and the supply of gas in their areas. In addition, DEPA, the main gas supplier in Greece, is the owner and operator of three (3) distribution networks in three (3) areas known as new-EPA areas. DEPA also owns a small distribution system in Corinth (with only one industrial client).

According to article 82 of the Greek Gas Law (law no. 4001/2011), access to EPAs' and DEPA's networks is granted to other suppliers serving only eligible customers. According to the same law, Eligible Natural Gas Customers were customers with annual natural gas consumption, for two consecutive years, of more than 100 GWh GCV of natural gas.

In 2014, two laws were passed which redefined the term Eligible Natural Gas Customers. Law no.4254/2014, redefined Eligible Customers inside the EPA areas customers who used to be eligible as of 31 December 2012. In other areas (outside EPAs' areas), Law 4301/2014 redefined Eligible Customers as all non-domestic customers.

In 2015, Law 4001/2011 was amended by Law 4336/2015 (Government Gazette A' 94/ 14.08.2015) which promoted the total reform of the gas market and provided for the full liberalization of the natural gas distribution market in Greece and the removal of the monopoly power in the natural gas supply from the existing EPAs.

Law 4336/20015 introduced the obligation for the unbundling of the distribution activities from the supply activities by January 1st, 2017. As a part of the reform, RAE acquired a decisive role in matters relating to the functioning of the EPAs and DEPA and their switching to legally separated companies, where the DSO (renamed as EDAs) will be responsible for the distribution system and the EPAS and DEPA will be just the gas suppliers.

According to the provisions of Article 8 of Chapter III of the Law 4336/2015, the old Licenses for Supply & Distribution which were granted to EPAs will be abolished in the end of 2017.

Law 4336/2015 specifies the timing of the separation timing of the distribution activities and supply of gas to existing EPAs and DEPA:

- From 1.1.2016, companies are required to keep in their internal accounts separate accounts for each of their activities, about the activities of distribution, supply to eligible customers, supply to non-eligible customers and Supply of Last Resort.
- By 30.5.2016, each company is required to submit to RAE for approval the accounting unbundling rules and principles. RAE shall decide thereon within three (3) months from the time of submission.
- By 1.1.2017 the three EPAs and DEPA should move towards functional and legal separation, with the establishment Gas Distribution Company (EDAs)

Law 4336/2015 also provided for the widening of the "Eligible Customers" category. All customers will be eligible as of 1/1/2018, a measure that contributes to the full opening of the retail market.

On 4th August 2016 s, new law (Law 4414/2016) identify the new process of unbundling of the natural gas Transmission System operator (DESFA) from DEPA S.A. Legislation will be amended, further facilitating the unbundling process: a) of the natural gas TSO (DESFA SA) by DEPA and b) the regional natural gas retail corporations (EPAs) - separation of the ownership and operation of distribution systems from retail operation activity. Separation of EPAs from DEPA. RAE is working for the completion of the unbundling process. These actions will lead to the development of a wholesale market.

4.1.2 Technical functioning

The National Natural Gas System (NNGS) transports Natural Gas to consumers connected to the NNGS in the Greek mainland from the Greek-Bulgarian borders, the Greek-Turkish borders and the Liquefied Natural Gas (LNG) terminal, which is installed at Revithoussa island at Magara (Athens/Attica region). More specific, there are three entry points into the national gas system: 1) the entry point “Sidirocastro” (Greece-Bulgaria border) with an interconnection technical transmission capacity 121.600 MWh/day, 2) the entry point in “Agia Triada” (LNG terminal) with an interconnection technical transmission capacity 150.000 MWh/day and 3) the entry point in “Kipi” (Greece-Turkey border) with an interconnection transmission capacity 49.000MWh/day.

During the year 2016, the total natural gas deliveries at NNGTS entry points amounted to 44,7 TWh compared to 34,3 TWh in 2015 and to 31,8 TWh during the year 2014. Sixty four percent (64%) of total deliveries came from the interconnection point Sidirokastron, sixteen percent (16%) from the interconnection point Kipi, and twenty (20%) percent from Agia Triada (including LNG for balancing purposes).

Table 47: Natural gas import deliveries to the interconnection points (borders) Greece, in 2016 (MWh)		
Sidirokastro (Greece Bulgaria border)	28.610.804,48	64%
Kipi (Greece - Turkey border)	7.152.701,20	16%
Agia Triada (Greece - Revithoussa border)	8.940.876,40	20%
Total	**44.704.382,00**	**100%**

According to the provisions regarding gas balancing services, as set in the relevant Greek legislation, DESFA S.A. prepares and submits every year to RAE an annual balancing plan for approval. The balancing plan includes TSO’s estimated natural gas needs for network balancing as well as an evaluation of possible balancing gas supply sources for the next year. The plan also includes DESFA’s proposal regarding the characteristics of the balancing contracts for the next year. To this effect, DESFA S.A. can either procure balancing gas directly from the long-term LNG contract of the incumbent (in line with an interim – transitional – provision of the Greek Gas Law), or procure balancing gas through a market based approach, in the form of an international tender procedure (in line with the basic provisions of the Gas Law).

With its Decision 219/2015, RAE approved the annual balancing plan submitted by DESFA S.A. to the Regulator for the year 2016, which included TSO’s estimated balancing the network natural gas needs (approximately 1.670.000 MWh), as well as an evaluation of possible balancing gas supply sources for 2016. According to this plan, TSO proposed to acquire balancing gas (in the form of LNG) for the balancing needs of 2016 through an international tender procedure, according to the main provisions of the Greek Gas Law. Furthermore, RAE with the same Decision, approved the monthly capacity reserved by the TSO for balancing services. In the 2015 balancing plan, the TSO had estimated that the balancing gas needs for the year would be recorded to 3.3% of the total estimated gas consumption, while the year-end data indicated that this figure recorded to 3%. For the year 2016, TSO estimated that the balancing natural gas needs will be recorded to 3.8% of the total estimated gas consumption. All costs arising from the provision of balancing services are recovered by the TSO through relevant charges paid by the users, so that the TSO is cash-neutral.

RAE is responsible for approving the balancing costs and the methodology for allocating these costs to the Transmission System users. With its Decision 470/2015, RAE approved the balancing cost allocation scheme and the relevant shippers' charges, which include all costs arising from the provision of balancing services for the year 2015. The corresponding charges include:

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

All balancing charges and the methodology for their calculation, as well as the Daily Balancing Gas Price, are published on DESFA's website, in both Greek and English.

At the end of the first quarter of 2015 DESFA submitted to RAE an interim measures report per the provisions of Chapter X of the European Network Code on Balancing 312/2014 (NC on BAL), as the absence of sufficient liquidity in the Greek natural gas market was not conducive to the full application of the provisions of the European Network Code on Balancing in 2015. RAE evaluated the interim measures report per the provisions of articles 46 and 27 of the NC on BAL and approved it with its 274/2015 Decision. The proposed interim measures include the continuation of the existing balancing scheme, the creation of a balancing platform per article 47 of NC on BAL that can evolve into a trading platform and further proposals in the regulatory framework with the purpose of alignment with the Balancing Regulation. Full implementation of the Balancing Regulation is expected by 16.04.2019 when NC on BAL shall enter into full force.

Therefore, in the meantime, the TSO has a primary role in balancing the system with balancing services acquired by a market-based procedure (international tender). All costs arising from the provision of balancing services are recovered by the TSO through relevant charges paid by the users, so that the TSO is cash-neutral. RAE is responsible for approving the balancing costs and the methodology for allocating these costs to the Transmission System users.

All balancing charges and the methodology for their calculation, as well as the Daily Balancing Gas Price, are published on DESFA's website, in both Greek and English.

In the framework of the interim measures report a balancing platform is planned to be operated by the Greek TSO in the second semester of 2017. The operation of the platform will allow all shippers active in the market to trade their imbalance positions and increase liquidity in the Greek gas market. The TSO is also provided to participate in the balancing platform to acquire gas for balancing purposes and therefore increase liquidity on the platform. RAE is monitoring the implementation of the interim measures approved with the intent to have full implementation of NC BAL by April 2019.

4.1.3 Network and LNG Tariffs for Connection and Access

A. Transmission System and LNG terminal access tariffs

Up to January 2013, the Third-Party Access (TPA) ratification system was set by the Ministerial Decision 4955/2006. In July 2012, RAE approved a new Tariff Regulation (RAE's Decision 594/2012, Government Gazette B' 2093/5.7.2012), which established entry-exit tariffs, in line with the provisions of Regulation (EC) 715/2009. Subsequently, through its Decision 722/2012 (Government Gazette B' 2385/27.8.2012) entitled "Approval of the National Natural Gas System Tariffs", RAE approved the entry-exit tariffs to be applied as of the 1st of February 2013, in accordance with the provisions of the new Tariff Regulation. This development constituted a major step forward in reforming the TPA system, towards a decoupled entry-exit regime, in full compliance with the EU Gas Regulation. Accompanied by the necessary revisions in the Gas Network Code, to allow for separate entry-exit capacity booking, a fully-fledged entry-exit system was, therefore, set in place in 2013.

The actual tariff coefficients for the year 2016 are presented in the table 48, below:

Table 48. Coefficients of TPA tariffs for one-year duration contracts in 2016

Tariff	Transmission Capacity Charge (€/peak day MWh/year)	Power Cconsumption's Charges (€/MWh)
Entry Sidirokastro	130,2961	0,1157
Entry Kipi	119,4398	0,0889
Entry Ag. Triada	24,6326	0,0498
Exit Northeast Zone	64,6789	0,1298
Exit North Zone	250,4859	0,3973
Exit South Zone	353,3965	0,4817
LNG Terminal	56,0579	0,1134

As of February 2013, in case of a short-term contract for the use of the Transmission System or the LNG Terminal, the capacity coefficients of the 1-year contract, as presented above, are reduced proportionally to the part of the year, calculated in days, during which the contract is in force, and are multiplied by a factor (B) which corresponds to the total duration of the contract.

The coefficients B are calculated according to the following formula, as set in RAE's Decision 722/2012:

B (d) = a * e-bd, (B d >=365 = 1)

where a and b are fixed parameters, and d is the duration of short-term services, in days, for the use of the Transmission System or the LNG terminal. The specific parameters used for calculating the coefficient B are defined as: a = 1.794793, b = 0.001602. Thus, the values of Factor B range from 1,791919 for a 1-day contract down to 1 for a 365-day contract.

DESFA S.A. publishes on its website the current and historical TPA tariffs, as well as a relevant calculator, in both Greek and English

B. Distribution System access tariffs

As described above, the three EPAs, EPA Attikis, EPA Thessalonikis and EPA Thessalias were operating under a regime of exclusive rights for both the activities of operating the distribution systems (DSO) and the supply of gas in their areas. In addition, DEPA, the main gas supplier in Greece, is the owner and operator of three (3) distribution networks in three (3) areas known as new-EPA areas. According to article 82 of the Greek Gas Law (law no. 4001/2011), access to EPAs' and DEPA's networks is granted to other suppliers serving eligible customers.

Before the new law 4336/2015, Tariffs for TPA in EPAs' distribution networks were those set in their concession licenses. The new Law 4336/2015, states that RAE must approve distribution tariff regulations and since then, the TAP tariffs are set to 4€ / MWh.

In 2016, RAE approved a gas distribution tariff regulation (RAE's Decision 328/2016) which will provide the methodology for calculating gas distribution tariffs for the three distribution system operators (EPAs). The calculation of the regulated tariff is based on the methodology of the Allowed Revenue Rate.

Allowed Revenue = Allowed Return on the Regulated Asset base + Depreciation of Assets + Operating Costs – Other Revenue + Any Recovery Cost Difference.

Table 49: Main parameters for the calculation of the regulated retail tariffs in the gas market, in Greece, in 2016
WACC (pre tax) 9,23%
Marginal return price 5,23%
Systemic Risk of capital 0,42%
G (loan) 0
Country Risk premium 4%
Cost of equity post tax 6,55%
Tax rate 29%
Cost of equity pre tax 9,23%
Debt rate 0

The approved regulated distribution tariff is covering a regulated period of 4 years for every distribution system, separately.

4.1.4 Cross-border issues

During the year 2016 the final recommendation of DESFA S.A. on the Ten Years Network Development Plan 2016-2025 (TYNDP 2016-2025) was officially submitted to RAE for approval, after being put into two public consultations, one run by the TSO and the second by RAE. RAE approved the TYNDP 2016-2025 (Decision 458/2015, Official Gazette B 2753/2015), according to the provisions of the Greek legislation and the Gas Network Code, and submitted a copy of the approved plan to ACER. The consistency of the TYNDP 2016-2025 has been checked against both the regional and the European TYNDP.

Table 50. Gas Supply Authorisation:

	Company
1	DEPA S.A.
2	PROMETHEUS GAS S.A.
3	M AND M GAS CO
4	HELLAS POWER S.A.
5	EDISON HELLAS S.A.
7	ENIMEX GAS ltd
8	TERNA S.A.
9	HERON THERMOELECTRIC S.A.
10	GUNVOR INTERNATIONAL B.V.
11	GREEK ENVIRONMENTAL & ENERGY NETWORK A.E.
12	GASELA GmbH
13	HELLAS EDIL S.A.
14	GREENSTEEL – CEDALION COMMODITIES A.E.
15	WATT AND VOLT A.E.
16	NRG TRADING HOUSE A.E.
17	SOURLAS S.A. CONSTRUCTIONS
18	EPA ATTIKI S.A.*
19	EPA THESSALONIKI S.A.*
20	EPA THESSALIA S.A.*
21	MAKIOS S.A.
22	ELINOIL S.A.
23	PROTERGIA AGIOS NIKOLAOS POWER S.A.
24	ALOUMINION S.A.
25	VOLTERRA S.A.
26	VIENER. S.A.
27	CORAL S.A.
28	PNG LTD
29	AEGEON OIL S.A.
30	Q CAPITAL INTERNATIONAL PARTNERS LIMITED
31	REVOIL S.A.

According to the provisions of article 8 of Law No. 4336/2015 the existing EPA companies have the right by Law to supply natural gas to Eligible customers until the issuing of the license to supply natural gas according to the provisions of article 81 of Law No. 4001/2011

Furthermore, according to the Gas Law, any person wishing to become a shipper must be registered in the National Natural Gas System Registry, to conclude a (transmission or LNG) contract with the TSO. In 2016, fifty 50 companies were officially registered as potential users of the NNGS, eleven (11) of which were active (at least 1 trade a week) in 2015. The NNGS Registry is continuously being processed and updated by RAE.

Table 51. Companies officially registered as NNGS users		
	User's Name	**Status/Classification**
1	ALUMINIUM S.A	Eligible Customer
2	MOTOR OIL(HELLAS) KORINTH REFINERIES S.A.	Eligible Customer
3	PUBLIC POWER CORPORATION S.A. (DEI)	Eligible Customer
4	EDISON S.p.A.	Third party
5	PUBLIC GAS CORPORATION S.A. (DEPA)	Natural Gas Supplier
6	ELPEDISON POWER S.A.	Eligible Customer
7	ELFE S.A.	Eligible Customer
8	PROMETHEUS GAS S.A.	Third party
9	HERON THERMOELECTRIC S.A.	Eligible Customer
10	HERON THERMOELECTRIC STATION OF VIOTIA S.A.	Eligible Customer
11	M AND M GAS CO	Natural Gas Supplier
12	KORINTHOS POWER S.A.	Eligible Customer
13	E.ON RUHRGAS AG	Third party
14	STATOIL ASA	Third party
15	EDISON HELLAS S.A.	Natural Gas Supplier
16	TRANS ADRIATIC PIPELINE A.G.	Third party
17	GASTRADE S.A.	Third party
18	LARCO S.A.	Third party
19	ELPE S.A.	Third party
20	TERNA S.A.	Natural Gas Supplier
21	SOVEL S.A.	Eligible Customer
22	SIDENOR S.A.	Eligible Customer
23	FULGOR S.A.	Eligible Customer
24	HELLENIC HALYVOURGIA S.A.	Eligible Customer
25	PROTERGIA S.A.	Eligible Customer
26	GREEK ENVIRONMENTAL & ENERGY NETWORK A.E.	Natural Gas Supplier
27	BA GLASS GREECE S.A.	Eligible Customer
28	ANOXAL S.A.	Eligible Customer
29	ERLIKON WIRE PROCESSING SA	Eligible Customer
30	FITCO METAL WORKS SA	Eligible Customer
31	HALCOR METAL WORKS SA	Eligible Customer
32	ALUMAN S.A.	Eligible Customer
33	PAPYROS PAPER MILL S.A.	Eligible Customer
34	GREENSTEEL - CEDALION COMMODITIES SA	Natural Gas Supplier
35	SONOCO PAPER MILL AND IPD HELLAS SA	Eligible Customer
36	EP-AL-ME S.A.	Eligible Customer
37	DAIRY INDUSTRY OF XANTHI SOCIETE ANONYME "RODOPI"	Eligible Customer
38	INOTEX PRIVATE COMPANY	Third party
39	DIAXON PLASTIC PACKING MATERIAL ABEE	Eligible Customer
40	GDF SUEZ	Third party
41	HALYVOURGIKI INC	Eligible Customer
42	DUFENERGY GLOBAL COMMODITIES S.A.	Natural Gas Supplier
43	EPA ATTIKIS S.A.	Natural Gas Supplier
44	EPA THESSALONIKIS THESSALIAS S.A.	Third party
45	HELLAGROLIP S.A.	Eligible Customer
46	ELBAL S.A.	Eligible Customer
47	LPC S.A.	Natural Gas Supplier
48	NRG TRADING HOUSE S.A.	Natural Gas Supplier
49	CORAL S.A.	Natural Gas Supplier
50	VIENER S.A.	Natural Gas Supplier

During the year 2016, the total natural gas deliveries at NNGTS entry points amounted to 44,7 TWh compared to 34,3 TWh in 2015 and to 31,8 TWh during the year 2014. Sixty four percent (64%) of total deliveries came from the interconnection point “Sidirokastron”, sixteen percent (16%) from the interconnection point “Kipi”, and twenty (20%) percent from “Agia Triada” (including LNG for balancing purposes).

Until recently, there was no considerable competition in imports of natural gas in Greece, as the share of DEPA gas imports corresponded to more than ninety percent (90%) of total annual imports. In specific, the share of DEPA gas imports in 2014 reached ninety-five percent (95%) of total annual imports, and ninety-two percent (92%) in 2015. Only one (1) other company (big industrial consumer), beyond DEPA, imported natural gas in the country in 2014 and in 2015, representing the remaining five percent (5%) in 2014 and eight percent (8%) in 2015 of total imports.

In the year of 2016 DEPA reduced its annual contracted quantity in the GazProm Contract and a new importer has become active in the Greek gas market. The effect of this change is not yet evaluated by the Regulatory Authority but according to current estimates the share of DEPA gas imports may drop significantly (below eighty percent) because of this evolution in the year 2017 and onwards.

“Harmonization of the procedure for the exchange of the Interim Measures Reports between Greek and Bulgarian TSOs and NRAs.”

According to article 45 of the BAL Code: “In the absence of sufficient liquidity of the short-term wholesale gas market, suitable interim measures referred to in Articles 47 to 50 shall be implemented by the transmission system operators”, the first DESFA's report on Interim Measures was approved by RAE (Decision 274/22.7.2015) after consultation with EWRC that offered its positive opinion on the proposed measures. DESFA’s report includes a description and overview of the current situation of the natural gas market in Greece, the proposed interim measures and the reasons for applying them, as well as the incentives and actions to be undertaken by DESFA in the direction of suspension of the measures.

The signing of an MoU in July of 2015 among 15 EU and Energy Community countries in the Central Eastern Europe and South East European regions, namely the Central Eastern and South-Eastern European Gas Connectivity (CESEC) initiative, further boosted the regional cooperation for the acceleration in tackling the remaining technical and regulatory issues which hamper security of supply and the development of a fully integrated and competitive energy market in the region.

To this end, DESFA and Bulgartransgaz had repeated meetings in the first quarter of 2015, in the presence of the two Regulators as well as the Directorate General for Energy, in view of signing an Interconnection Agreement for the Interconnection Point Kulata-Sidirokastro. A first draft of this Agreement was set under public consultation by the two TSOs in June 2015. Discussions continued throughout 2015 and the Agreement was finally signed in July of 2016.

The second area of cooperation between the Greek and Bulgarian Regulatory Authorities is towards the realization of the Interconnector Greece-Bulgaria, IGB, pipeline project. During November and December of 2015, RAE and EWRC closely worked together for the overseeing of the second Market Test announced by the sponsor company ICGB AD to attract potential market interest for capacity booking at the new pipeline. More specifically, the National Regulatory Authorities of Bulgaria and Greece jointly updated the Guidelines for the management and allocation of capacity to the IGB Interconnector Project, per paragraph 6 of Article 36 of Directive 2009/73/EC, for the first phase of the Market Test, which refers to the invitation of interested parties to express their interest in reserving capacity in the above-mentioned project (RAE Decision 438/23.11.2015). Then, the Expression of Interest Phase Notice was also approved (RAE Decision 472/1.12.2015).

Finally, The Interconnection Agreement for the IP "Kulata (BG)-Sidirokastro (GR) (Bulgaria – Greece interconnection point), signed between the TSOs of Greece and Bulgaria in June 2016. The active support of RAE and EWRC and the guidance by the Commission, enabled commercial gas flow from Greece to Bulgaria starting the 1st of July 2016.

The Commission has welcomed the agreement as a crucial step towards implementing EU rules on one of the cross-border points of the EU where historic transit arrangements, dominated by a single company, prevailed. Therefore, thirty years after the operation of IP Kulata-Sidirokastro there is currently an IA in place for the operation of the IP per the provisions of the NC on Interoperability. The agreement strengthens the cooperation of the TSOs and the coordination of the two national transmission systems as well the ability of the two TSOs to implement NC CAM at the IP.

Implementation of NC CAM - Capacity auctions through the regional platform RBP

In 2016 both TSOs of Greece and Bulgaria selected the Regional Booking Platform as their preferred capacity booking platform for the implementation of NC CAM at the IP. The first capacity auctions for reserving capacity at the IP Kulata-Sidirokastro were successfully performed on the Regional Booking Platform on December 9, 2016.

No bundled capacity was offered since Bulgartransgaz announced zero capacity available on a firm-forward basis to the IP because all technical capacity at the Bulgarian side, in the flow direction BG→GR, has already been booked on a long-term basis. On the Greek side, all technical capacity of the IP minus 10% reserved for short term products was auctioned off. Nine six percent of the capacity offered on the Greek side was bided on and contracted by several shippers (105.000 MWh out of 109.196 MWh), indicating an increased participation of market participants in the capacity auctions compared to one shipper holding capacity in that point.

Further capacity auctions for quarterly, monthly and daily products are scheduled at the IP per the auction schedules announced on RBP, DESFA and Bulgartransgaz websites. In general, according to the data published on RAE's website in the National Natural Gas System Registry (NNGS) registry, including parties interested to ship gas in Greece, there is currently registered interest of fifty entities of which approximately fifteen to twenty have been active. The NNGS Registry is continuously being processed and updated by RAE.

Product trade at the Virtual Nomination Point

With the second amendment of the Gas Network Code in Greece in December 2013 to allow for the implementation of an entry-exit system and disentangle entry capacity booking from exit capacity booking a virtual nomination point (VNP) was established.

The establishment of the VNP along with the proposal of the Greek Regulator for the quantities released by the incumbent DEPA to be offered at the VNP resulted in more trade taking place at the VNP in the last couple of years, as evidenced in the table below which has been submitted to DG ENER by the Greek TSO for the CESEC meetings and workshop that took place in November 2016.

TABLE 52. TRADING VOLUMES AT THE VIRTUAL NOMINATION POINT

Trading volumes (in GWh)	Gas year 2015/2016	% change GY15-16/GY14-15	Monthly Average (for 12 months ending September 2016)	Monthly minimum (for 12 months ending September 2016)	Monthly Maximum (for 12 months ending September 2016)	Daily Average (for 12 months ending September 2016)	Monthly minimum (for 12 months ending September 2016)	Monthly Maximum (for 12 months ending September 2016)
OTC Spot (Day-ahead, Intraday)	19.562	**222**	1.630	883	2.760	53	15	108

TABLE 53. NUMBER OF TRADES AT THE VIRTUAL NOMINATION POINT

Number of trades	Gas year 2015/2016	% change GY15-16/GY14-15	Monthly Average (for 12 months ending September 2016)	Monthly minimum (for 12 months ending September 2016)	Monthly Maximum (for 12 months ending September 2016)	Daily Average (for 12 months ending September 2016)	Monthly minimum (for 12 months ending September 2016)	Monthly Maximum (for 12 months ending September 2016)
OTC Spot (Day-ahead, Intraday)	4929	**72**	411	342	499	13	8	17

(Note: the Greek gas market has not developed a spot market, a day ahead market and a forward market. It is expected to do so by the end of 2018).

The trades were executed at the Virtual Nominations Point (VNP) according to Users' Daily nominations submitted to the TSO. Though the TSO has no information regarding the trades' period agreed between the Users. As evidenced by the data above this is OTC spot (day-ahead) trade occurring among shippers at the Virtual Nomination Point. Per the data provided by the Greek TSO there has been a two hundred twenty two percent (222%) increase in the OTC trade volume and a seventy two percent (72%) increase in the trades number from GY 2014/15 to GY 2015/16.

Finally, RAE, in its role as the Competent Authority on ensuring the implementation of the measures foreseen in EU Regulation 994/2010 regarding security of supply is also cooperating with the Ministry of Energy of Bulgaria. Following consultation with the Bulgarian and Romanian Competent Authorities, which constitute Greece's neighboring countries per

Regulation EC 715/2009, in November of 2015 RAE updated the National Emergency Plan and the National Preventive Action Plan, as described in detail in Section XX.

In addition to the above, RAE continues an excellent cooperation with the Italian and Albanian Energy Regulators in the framework of the implementation of TAP project. During 2015, this collaboration continued with the reviewing of the Network Code, as is being developed by TAP.

Finally, following the MoU signed between the Greek and the Belgian Regulator CREG, and the agreement signed between the Greek and the Belgian TSO Fluxys, to exchange best practices and know-how in market regulation including gas hub developments, Fluxys continued into 2015 to guide DESFA to create a virtual trading point and create a liquid wholesale market in Greece.

4.2 Promoting Competition

4.2.1 Wholesale Market

Greece has not developed an organized wholesale market in the natural gas sector and all the transactions are based on bilateral contracts between the suppliers and the eligible consumers (over the counter contracts) with a pre-defined delivery point of the agreed traded quantity of natural gas either at the Virtual Delivery Nomination Point of the National Natural Gas System or at a physical delivery point.

RAE has repeatedly stressed that, under the current operating conditions of the Greek gas market (i.e. limited storage capacity of the transmission system, and the applied restrictions on the existed importing supply contracts due to commitments on “a destination clause” and on “a take or pay clause”), DEPA’s commitment for its own gas release (sale) program is currently, the only case for natural gas’ supply to third parties - consumers and suppliers - and hence, currently, the only way possible to develop competition in the wholesale gas market, in Greece.

During 2015 and 2016, RAE provided opinions to the Hellenic Competition commission (HCC) on ways to optimize the functioning of the incumbent’s gas release (sale) program in the framework of an extensive consultation run by HCC whereby all major gas market players participated in. Thus, to offer Suppliers and Customers the ability to put together a flexible portfolio for the supply of natural gas and in addition to the current system of quarterly auctions, DEPA has undertaken to make natural gas available on an annual basis in the electronic auctions, i.e. with an absorption period of one calendar year (annual auctions). Additionally, to further reduce dependence of DEPA Customers by DEPA and to equally treat all participants in the auctions, irrespective of the supply contract that they have concluded with DEPA (with or without transmission services), DEPA undertook (as of 01.01.2015) to make all quantities available through the annual and quarterly auctions solely at the Virtual Nomination Point (VNP) of the National Natural Gas System (NNGS).

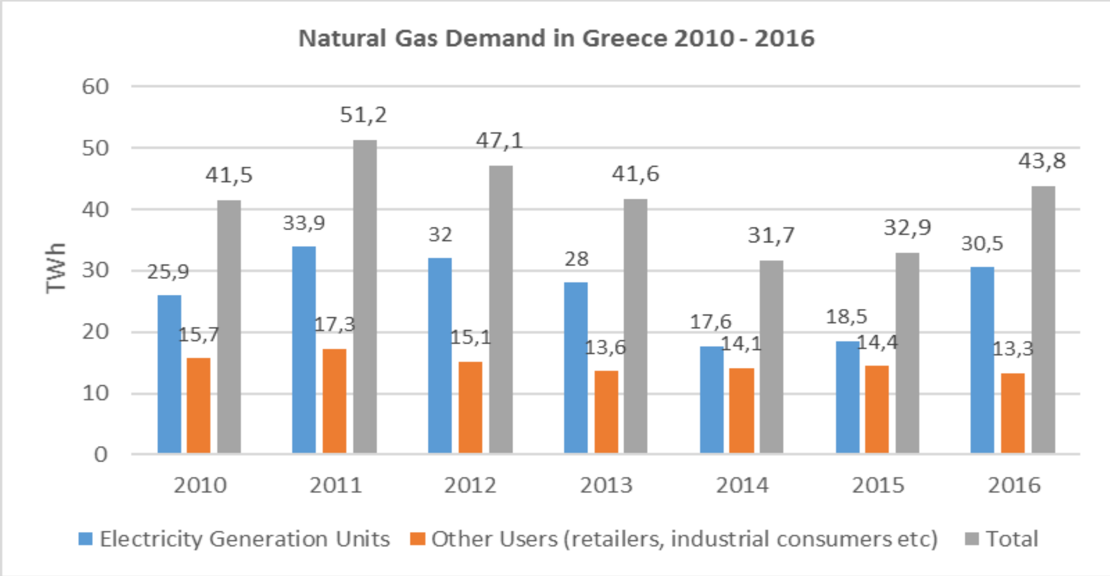


Figure 19: Natural gas Demand in Greece

Until recently, there was no considerable competition in imports of natural gas in Greece, as the share of DEPA gas imports corresponded to more than ninety percent (90%) of total annual imports. In specific, the share of DEPA gas imports in 2014 reached ninety-five percent (95%) of total annual imports, and ninety-two percent (92%) in 2015, and a similar number in 2016. Only one (1) other company (big industrial consumer), beyond DEPA, imported natural gas in the country in 2014, in 2015 and in 2016, representing the remaining five percent (5%) in 2014 and eight percent (8%) in 2015 of total imports.

In 2016 DEPA reduced its annual contracted quantity of the GazProm Contract and a new importer has become active in the Greek gas market. The effect of this change is not yet evaluated by the Regulatory Authority but according to current estimates the share of DEPA gas imports may drop significantly (below eighty percent) because of this evolution in the year 2017 and onwards.

RAE, within the framework of its competences regarding monitoring of the Greek energy market, publicized for the first time in 2011, data on the calculated Weighted-Average Import Price (WAIP) of natural gas in the NNGS, monthly. The publication of data on WAIP, in combination with the publication of data on daily prices of balancing gas (HTAE) on the TSO's (DESFA) internet site, allows current and potential market participants to gain a better understanding of the price conditions prevailing in the Greek market, and, therefore, to exploit business opportunities and enhance competition, to the final benefit of consumers. Furthermore, the publication of wholesale prices constitutes a necessity for the organization of a wholesale gas market. Figure 20 presents the monthly WAIP compared to the daily price of balancing gas (HTAE) for the same month, as announced on the internet site of DESFA, from January 2014 through December 2016.

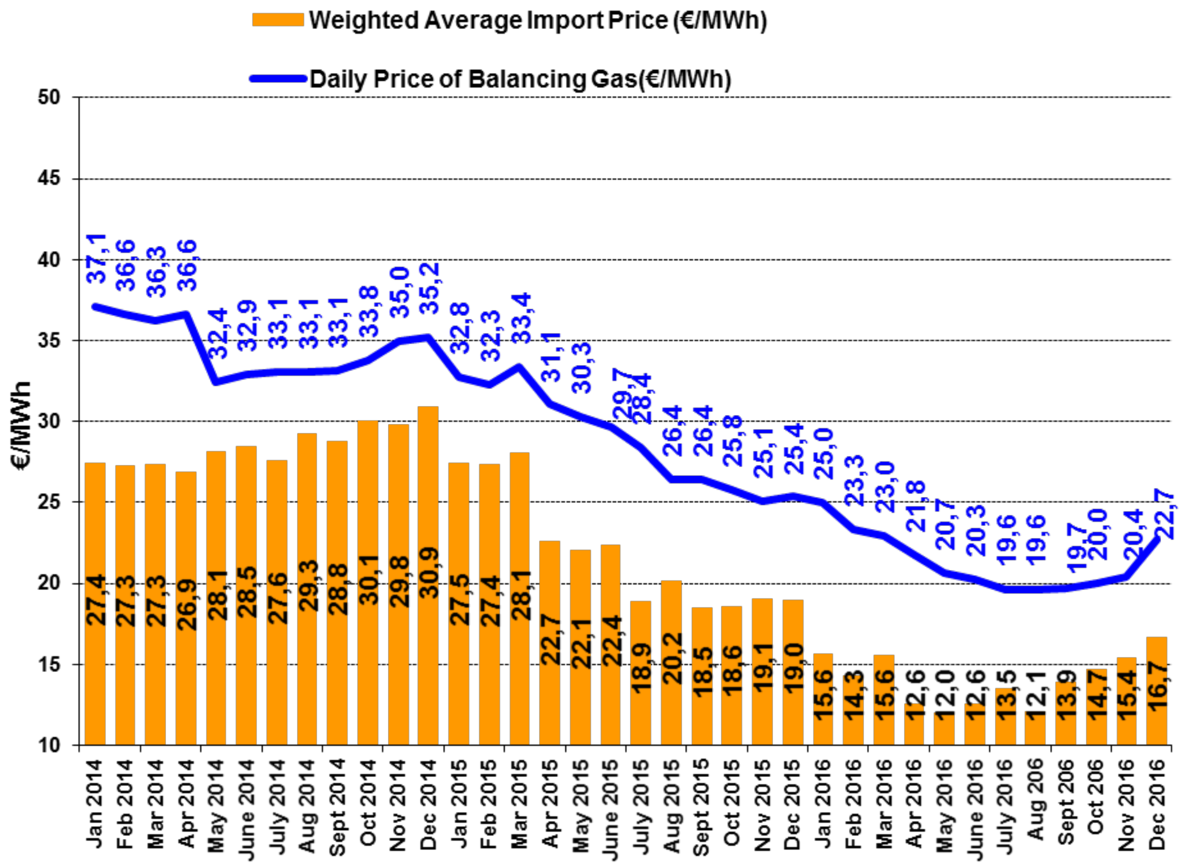


Figure 20. Price Monitoring in the Wholesale Market.

Data are published on RAE's website and updated on a regular basis Starting in April 2011, the deviation of HTAE from the Weighted-Average Import Price is mainly attributed to the change in the price of balancing gas through procurement, which constitutes the basis for the calculation of HTAE. Based on the contracts signed by the TSO for procuring balancing gas, the price of procuring balancing gas only includes a proportionate charge, which incorporates the fixed amount paid out by the Transmission Operator per the previous regime and which was not considered in the calculation of HTAE, but was further distributed to the System's users as a distinct charge.

4.2.1.1 Monitoring the level of transparency

Market Opening and Competition

There was no new major infrastructure, such as new entry points, LNG or storage facilities, commissioned in 2016. As explained in previous National Reports, there is no indigenous natural gas production in Greece. Furthermore, there are no storage facilities and the LNG storage tanks are used exclusively for temporary LNG storage. Therefore, as has been noted in the past and was fully confirmed in 2016, the LNG terminal on the small island of Revithoussa close to the Attica region and to the city of Athens, remains the main channel/opportunity for new entrants into the natural gas market.

During the 2010-2012 period, when there was considerable competition in imports of natural gas in Greece, the share of DEPA gas imports corresponded to about ninety percent (90%) of total annual imports. However, the share of DEPA gas imports reached ninety-nine percent (99%) of total annual imports in 2013 and ninety-five percent (95%) in 2014. In 2015 there was a further reduction in DEPA's share of gas imports which reached ninety-two (92%) of total annual imports. Beyond DEPA, one (1) other company (big industrial consumer) imported natural gas in the country in 2015, representing the remaining eight percent (8%) of total imports. The gas market is still organized based on bilateral contracts between suppliers and eligible customers; no organized wholesale market exists yet. Transactions that have been recorded so far are the result of the following mechanisms: a) wholesale trading of LNG quantities in-tank, b) resale of gas between eligible customers, and c) gas release programs run by DEPA, with the third one gaining ground during 2015.

DEPA runs electronic auctions on a quarterly basis since December 2012 per the provisions of the Hellenic Competition Commission (HCC) Decision 551/VII/2012 and on an annual basis since December 2014 (HCC Decision 589/2014) after RAE's intensive effort.

RAE provided an extensive opinion to HCC on ways to optimize the functioning of the gas release programs in the framework of an extensive consultation run by HCC whereby all major gas market players participated in. Thus, to offer Suppliers and Customers the ability to put together a flexible portfolio for the supply of natural gas DEPA has undertaken the commitment to make natural gas available on an annual basis through electronic auctions. Additionally, to reduce further the dependence of Consumers on DEPA and to equally treat all participants in the auctions DEPA undertook, as of 01.01.2015, the commitment to make all quantities available through the annual and quarterly auctions solely at the Virtual Trading Point (VTP) of the National Natural Gas System (NNGS).

4.2.2 Retail Markets

Besides DEPA S.A., which supplies gas at the wholesale and the retail level, and the self-importing/self-consuming eligible customers, there are three (3) distribution companies (known as EPAs), which supply gas to non-eligible customers, each being a monopoly in a specific geographical area: EPA Attica, EPA Thessaloniki and EPA Thessalian. DEPA S.A. owns 51% of each EPA, thus, by the domination principle, DEPA holds at the retail level the same share as in the wholesale market.

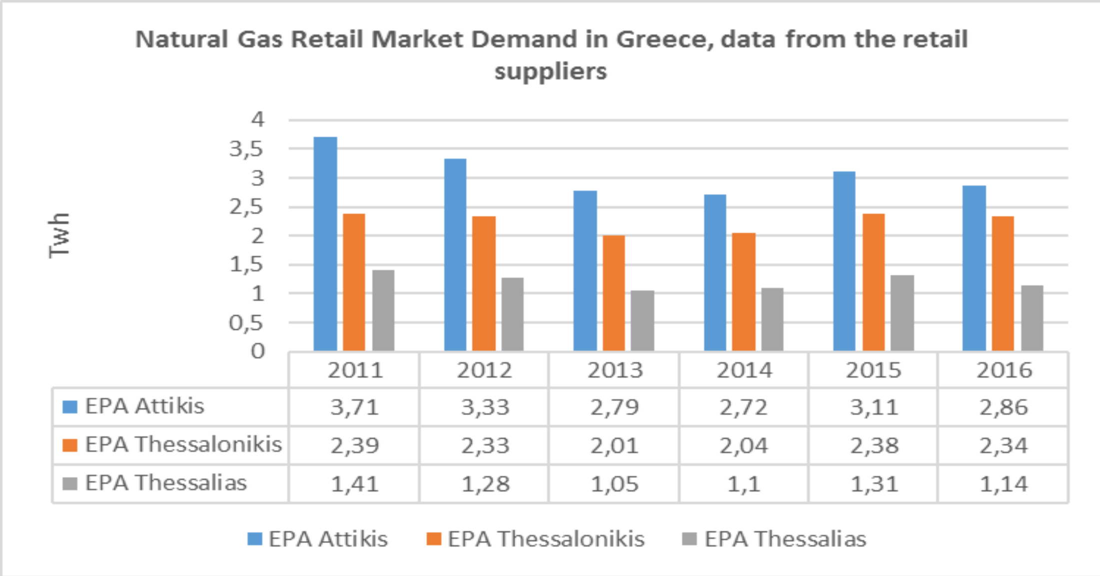


Figure 21. Retail Market Demand.

In October 2011, EPA Attica changed its methodology for setting customer tariffs, the previous one linking natural gas prices to the price of oil. From 1 October 2011, the EPA Attica pricing methodology is cost-based and is like those of EPA Thessaloniki and EPA Thessalian. Natural gas prices for residential, professional and commercial consumers result from the summing up of: a) the cost of gas supply, b) the distribution margins and c) taxes.

Overall, average end-user prices in 2016 were lower than the corresponding prices in 2015 and 2014. The most important drivers of natural gas cost plus tariffs are international fuel prices (FO, GO, Crude) and inflation. Some indicative annual average prices for EPA Attica, EPA Thessaloniki and EPA Thessalia are presented in the table below.

Table 54 below shows the average household end-user bundled price (€/MWh) for supply and distribution

Table 54. Indicative, annually-averaged, household tariffs, 2012- 2016 (€/MWh)			
	EPA Attikis	EPA Thessalonikis	EPA Thessalia
2012	62,96	61,40	59,28
2013	57,66	57,19	55,63
2014	54,59	48,87	49,42
2015	48,17	43,85	44,77
2016	40,35	36,56	37,41

Table 55. Indicative, annually-averaged, Commercial tariffs, 2012- 2016 (€/MWh)			
	EPA Attikis	EPA Thessalonikis	EPA Thessalia
2012	63,96	63,01	60,91
2013	58,66	58,82	57,29
2014	55,59	50,51	51,08
2015	47,17	45,48	46,43
2016	39,36	38,20	39,07

Table 56: The total Number of the consumers in the retail market (households, commercial customers), annually.						
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
EPA Attikis	74.000	78.000	61.000	86.000	94.000	98.000
EPA Thessalonikis	144.000	155.000	164.000	172.000	196.000	204.000
EPA Thessalias	49.000	55.000	62.000	67.000	78.000	82.000

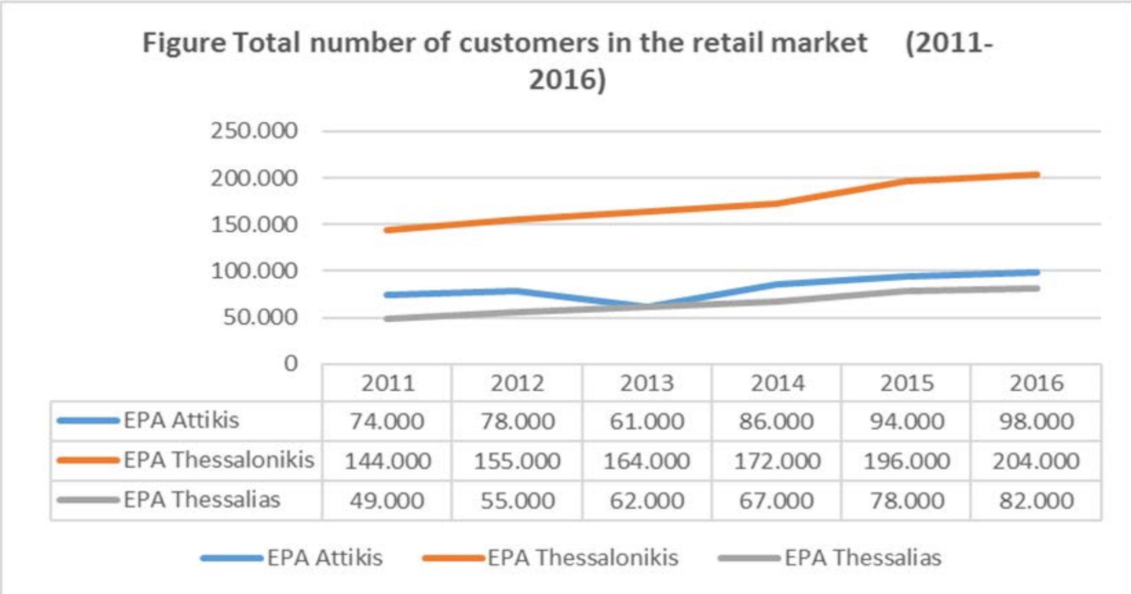


Figure 22. Total Number of customers.

Table 57. Natural gas demand by sector in 2016 (bcm/year)		
	bcm	**Mtoe (HHV)**
Power consumption	2,871	2,584
Industry & HP customers	0,571	0,514
GDCs (Primarily commercial & domestic)	0,678	0,610
TOTAL	4,120	3,708

4.3 Consumer Protection

4.3.1 Compliance with Annex 1 of EU Directive 2009/73/EC

Consumer protection provisions, as described in Annex 1, par. 1 of Directive 2009/73/EC, have been partially incorporated in the Distribution Licenses of the three EPAs. The EPAs provide on their websites all necessary information regarding offered services and end-user prices per customer category. Moreover, they provide telephone lines through which customers may obtain information regarding prices, connection fees, connection details, etc. They are also obliged to handle customer complaints and to respond to them within a set deadline, as well as to offer a wide choice of payment methods to their customers.

4.3.2 Definition of Vulnerable Customers

The provisions of Law 4001/2011 for vulnerable consumers have not yet been fully adopted by the three EPAs, in terms of compliance with a) the categories of vulnerable groups, and b) economic protection schemes. The Distribution License of each EPA, which operates under a regime of exclusive right for both the activities of distribution and supply of gas in its geographical area, include some noneconomic provisions for the so-called “Domestic Customers with Special Needs”. Since there is still no Ministerial Decision for the provision of specific conditions and economic protection schemes for such customers, these are currently defined by each EPA, based on transparent criteria per their Distribution License. The following categories of consumers are included:

- People with permanent disability caused by physical, psychological or mental impairment (people with movement disabilities, the blind and, generally, the sight impaired, the deaf, those who have difficulty in understanding, communication and adaptation, patients with atherosclerosis, epilepsy, kidney failure, rheumatic diseases, heart diseases, etc.).
- People suffering from temporary injury or disability caused by physical, psychological or mental impairment.
- People with limited ability for professional employment, due to chronic physical or mental illness or injury.
- People over 65 years of age, if they live alone, or with another person over the age of 65. Beneficial measures for the above domestic gas customers “with Special Needs” include:
    - Prohibition of disconnection due to an overdue debt, during the November to February winter period. Relocation of the consumption meter, for the customer with special needs to have easy access to meter readings.
    - Telephone service for blind customers, to be informed on meter readings.
    - Free visit to special needs customers, to inform them on safety measures in case of an emergency.
    - The customer with special needs has the right to assign another person for
    - Communication purposes (receiving bills, messages, etc.).

4.3.3 Handling of consumer complaints

Only a very small number of complaints (11) were filed to RAE in 2016 regarding the distribution and supply of natural gas in the EPA areas. The most frequent complaints concerned the bills, connection problems high connection charges and connection delays, as well as the exemption of single connections within an apartment building, from the common property charges for oil heating.

4.4 Security of Supply

During 2015, RAE's activities about security of supply (SoS) were focused on the update of the reports and plans which are foreseen for a regular update per the provisions of European Regulation 994/2010 concerning measures to safeguard security of gas supply, i.e., the Risk Assessment, the Preventive Action Plan and the Emergency Plan.

The gas quantity data provided in this section are expressed in both units of Mtoe (based on gas with a HHV of 9600 Kcal/Nm3) and bcm (at 15°C). All demand projections provided hereon are based on DESFA's projections in the 2016-2025 NNGS Development Study.

4.4.1 Monitoring Balance of Supply and Demand

4.4.1.1 Current demand

The demand for Natural Gas in 2016 recorded 4,12 bcm compared to 3,12 bcm in 2015, out of which approximately seventy percent (70%) came from the power generation sector, as shown in Table 58

Table 58. Natural gas demand by sector in 2016

	bcm	Mtoe (HHV)
Power consumption	2,871	2,584
Industry & HP customers	0,571	0,514
GDCs (Primarily commercial & domestic)	0,678	0,610
TOTAL	4,120	3,708

As depicted in Figure 23, total gas demand in 2016 increased significantly after 2 years when natural gas demand remained at approximately the same level (3,2bcm/year). The main reasons are; first, the decrease of the production of the lignite electricity generation units, therefore, natural gas generation units "called" to offset this reduction in the electricity volumes and second, the reduction in imported prices of natural gas made electricity generation using natural gas as a fuel, more attractive.

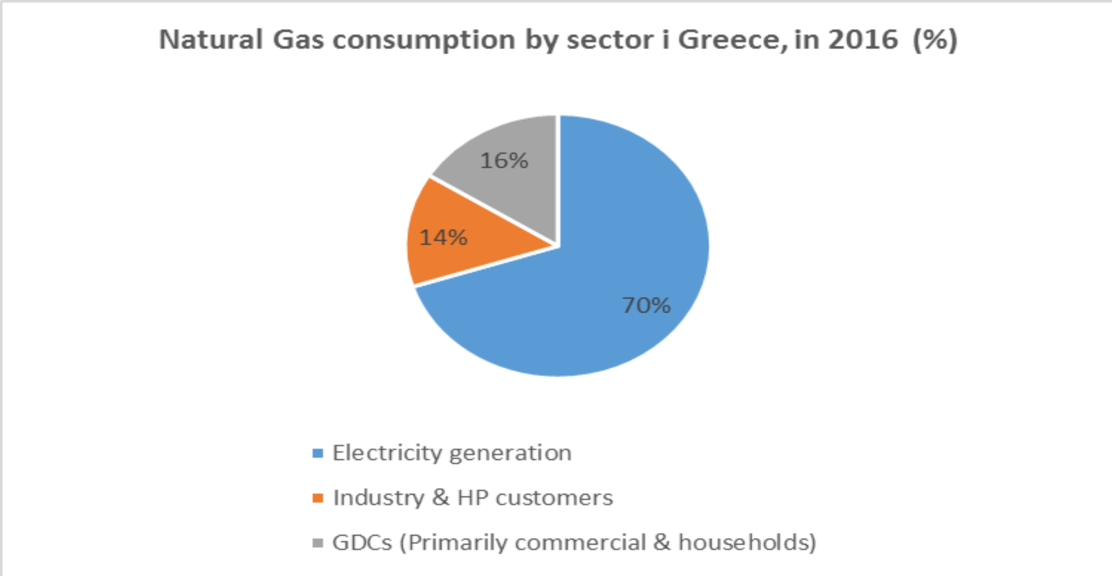


Figure 23. Share of natural gas consumption by sector

There is no indigenous gas production in Greece. In 2016, natural gas was imported in the National Natural Gas System through three (3) entry points. As shown in Figure 24, approximately sixty-four percent (64%) of the gas imported into the country came from Russia and sixteen percent (16%) was imported from Turkey. The remaining twenty percent (20%) was imported as LNG at the island of Revithoussa and was injected into the transmission system from the Agia Triada entry point. (i.e. But more than 90% of the imported natural gas continue to be delivered to one customer; DEPA, the only supplier of the wholesale market).

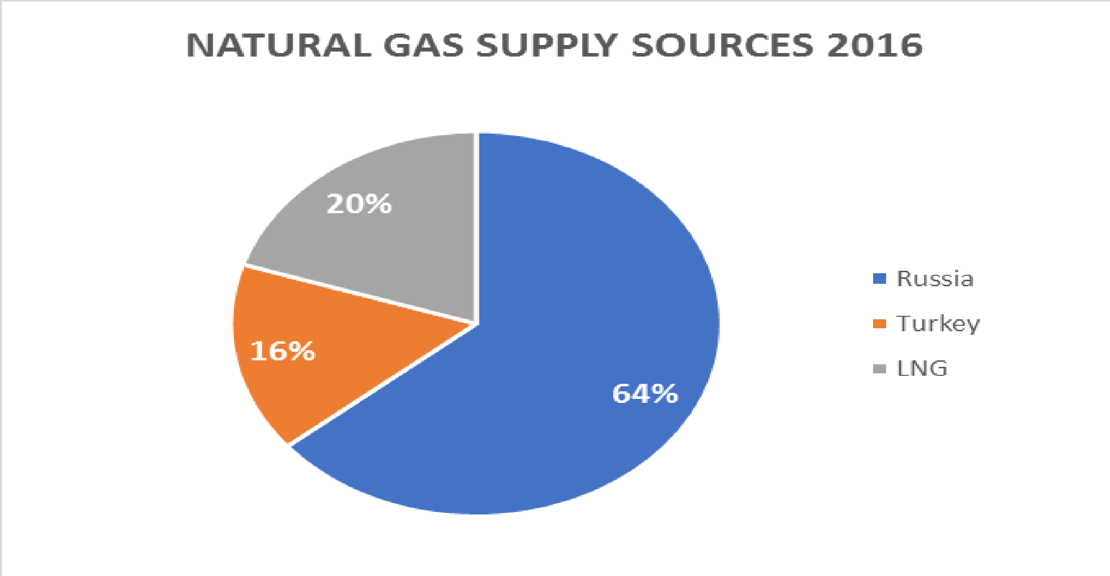


Figure 24. Share of natural gas supply sources in 2016

Figure 25 provides the share of imports from each source during the past ten (10) years (2007-2016). The supply of gas through the existing long-term contract with Russia appears to stabilize at around sixty percent (60%).

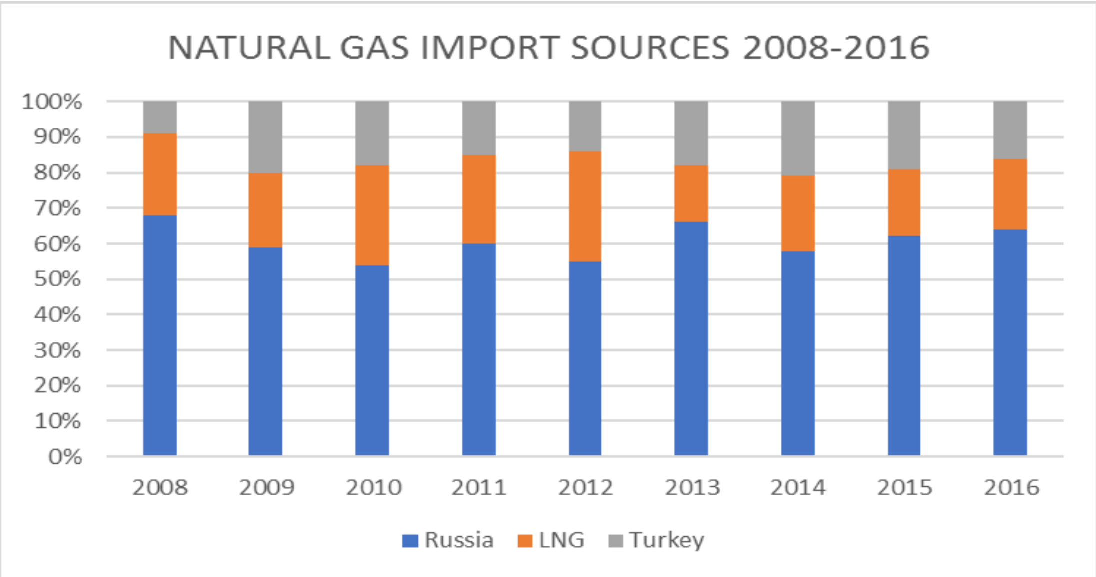


Figure 25. Share of natural gas import sources, from 2007 to 2016

4.4.1.2 Projected demand

Natural gas demand is expected to rise in the next three years (2016 to 2018) compared to the natural gas demand of 2015. This is largely influenced by market conditions, the projections of global institutions for Brent crude oil (price) in the forthcoming years and the energy available for imports and hydro production.

Table 59. Future natural gas demand (DESFA's estimates)						
	2017		2018		2019	
	bcm	Mtoe	bcm	Mtoe	bcm	Mtoe
Power generation	2,021	1,8189	2,029	1,8261	2,057	1,8513
Industry	0,841	0,7569	0,859	0,7731	0,874	0,7866
Commercial & households	0,428	0,3852	0,450	0,405	0,470	0,423
Total	3,290	2,961	3,338	3,004	3,401	3,061

4.4.2 Expected Future Demand and Available Supplies

During 2016, DEPA imported gas primarily through existing long-term contracts from three (3) different sources, namely Russia, Algeria (LNG) and Turkey, while several spot cargoes sourced from Norway and Spain were also unloaded at Revithoussa.

Table 60 presents the anticipated supply-demand balance for the next three (3) years, based on the expected demand and the existing long-term supply contracts. It becomes evident that the existing long term contracts (the first of which expires at the end of 2020) are insufficient to cover the anticipated demand, in the years 2017 and 2018, unless a new supplier enters a new long term supply contract.

Table 60. Expected natural gas supply-demand balance, 2017-2019						
	2017		2018		2019	
	Bcm	Mtoe	bcm	Mtoe	bcm	Mtoe
Demand	4,111	3,699	3,678	3,310	3,401	3,061
Supply contracts	5,107	4,596	3,610	3,249	3,427	3,084
Supply gap	0,996	0,897	-0,068	0,273	0,026	0,023

Figure 26 below shows the expected demand - supply balance up to 2025. The demand curve corresponds to the TSO's demand forecast.

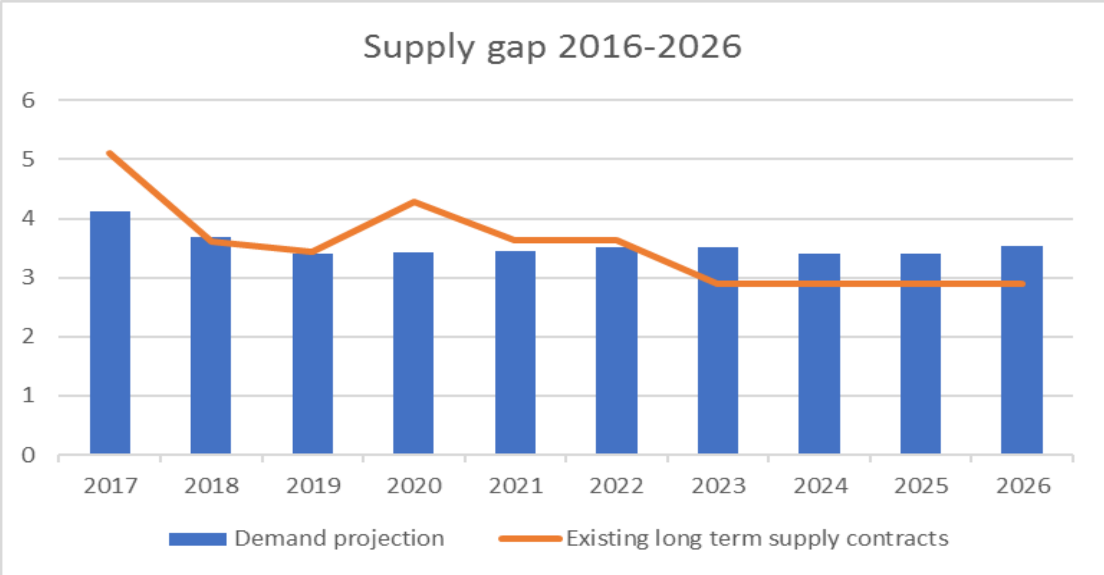


Figure 26. Expected natural gas supply-demand balance (forecast to 2026)

The National Gas Transmission System has three (3) entry points, two at the North and North-eastern borders - Sidirokastro and Kipi - connecting with the Bulgarian and the Turkish gas networks, respectively, and one at the Southern part, where gas from the Revithoussa LNG terminal is injected into the System.

Table 61 below lists the current entry-point capacities. These capacities reflect current figures published by the TSO, based on upstream and downstream network constraints. The annual figures have been estimated based on a load factor of 100% for all entry points.

Table 61 Natural gas entry-point capacities	
Entry points	Bcm (15^{0}C)
Sidirokastro	4,184
Kipi	1,676
Ag. Triada (LNG terminal)	5,170
TOTAL	11,03

above lists the TSO's investment plans, which aim to add import capacity to the NGTS. The plans are based on the Revithoussa LNG terminal upgrade, including a) the upgrade of the docking/marine facilities, b) the increase of the terminal's storage capacity by the addition of a third storage tank, c) the increase of the regasification capacity, and d) the upgrade of the Agia Triada M/R to match the upgraded regasification capacity.

The project for the construction of the third storage tank has already been awarded to the EPC contractor and its completion is expected by the end of the year 2017. Once the terminal upgrade is completed, the total import capacity into the NNGS by the three (3) existing entry points will increase from 10 bcm/year to 12.5 bcm/year.

Project	Implemented by	Completion by
Revithoussa Terminal upgrade	TSO	End of 2017

Natural gas TSO investment plans

4.4.3 Measures to Cover Peak Demand or Shortfall of Suppliers

As mentioned before, during 2015, RAE focused on the update of the reports and plans per the provisions of European Regulation 994/2010 concerning measures to safeguard security of gas supply.

A short term and medium term strategy were adopted in the Preventive Action plan approved in 2015 by RAE. These strategies are still in the implementation phase.

a. The short-term strategy aims to address security of supply issues in the short term i.e. up to 2 years ahead (short term strategy).
b. The medium-term strategy aims to provide increased security of supply in the medium term i.e. 3 to 6 years ahead (medium term strategy).

4.4.3.1 Implementation of the Short - term strategy

The short-term strategy of the 2015 Preventive Action Plan was composed of the following actions:

1. *Implementing market based Demand side response (DSM).*

An incentive scheme is under development for demand side response from Large Customers (primarily Industrial). The scheme is designed for demand response at the level of around 1.5 mcm/day, with compensation financed through a security of supply levy, enacted in September of 2014, paid by all gas consumers.

DSM is expected to take place during supply crises through the following two schemes:

- Large Industrial Interruptible customers self-commit in advance of the crisis to reduce their demand by at least forty percent (40%) following the declaration of an “alert” crisis. In return they are rewarded because they do not pay any the security of supply levy.

- Large Industrial Non-Interruptible customers may choose during the crisis to reduce their demand in exchange for a payment for non-consumed gas. Suppliers are incentivized to offer attractive compensations to their customers for non-consumption on a voluntary basis since suppliers and therefore their customers will be compensated by TSO payments financed through the Security of Supply Levy.

2. *Implementing measures to enhance dual fuel availability*

The implementation of measures to enhance the availability of CCGTs with dual fuel capability aims to optimize the use of existing infrastructure. The measures focus on:

- The conclusion of contracts between the gas TSO (DESFA) and CCGT operators with dual fuel capability for compensating certain cost elements of the CCGT operators through the security of supply levy to guarantee availability of these operators in a security of supply crisis.
- The amendment of electricity Grid Code provisions to ensure adequate available capacity from power plants with dual fuel capability during periods with high gas demand and ensuring compensation for operation with liquid fuel following instruction by the electricity TSO.

3. *Cost recovery mechanism*

On September 2014, a security of supply levy payable by all gas consumers was introduced, per the provisions of article 73 of Law 4001/2011. The levy is meant to finance the costs associated with:

- The establishment of an incentive scheme designed for demand response by Large Customers at the level of around 1.5 mcm/day.
- The readiness of availability of liquid fuel at power stations with dual fuel capability and the regular testing of the Power Plants on liquid fuel.

The SoS levy is set at a different level for each one of the following four customer categories: a) interruptible customers, b) gas-fired power plants, c) protected customers, and d) all other types of customers. The level of differentiation in the actual levy per customer category captures the different level of protection each customer category is offered according to the procedures foreseen in the national emergency plan.

In 2015 the cost recovery mechanism continued to be applied to all gas consumers connected to the gas network. The security of supply levy was adjusted per the formula approved by RAE in RAE's Decision no. 344/2014 resulting in a decrease of the levy given that no outflows of the SOS account were necessary in the previous year.

4.4.3.2 Implementation of the Medium - term strategy

The medium-term strategy presented in the 2015 Preventive Action Plan comprised of the following two options related to the development of new infrastructure for security of supply purposes:

1. The upgrade of the Revithoussa LNG terminal and
2. A new entry point which could be either a new Interconnector to Liquid Markets, an LNG Terminal or a UGS.

The first option of the medium-term strategy is being implemented as there are ongoing works at the Revithoussa Facility. The project is expected to be completed by the end of 2017.

The second option in the medium-term strategy is more complex and expensive as it requires the construction of a new energy infrastructure that will constitute a new entry point to the Greek Natural Gas System. The completion of any of the several PCI projects that are situated in Greece (i.e., TAP, IGB, the Aegean LNG Terminal, the Alexandroupolis LNG terminal and/or the Kavala UGS) will result into the creation of a new entry point to the Greek Natural Gas System and therefore diminish any residual risk for supply disruption to gas consumers.

4.4.4 Security of Supply crises

During the year 2016, RAE considering the possible future security of supply crisis and in response to the EU Directive 994/2010 article 9, approved the development of a demand crisis management mechanism. RAE's Decision 628/2016 approved specific standard types of contracts as follows: a) Standard Contract for an alternative fuel of supply, b) standard contract for Capacity Electricity Generation Reserves from an Electricity Generation Unit and c) a Standard Contract of Natural gas suppliers for a (demand) crisis' management financing mechanism.

The standard contracts of alternative fuel are signed between the TSO and the electricity Generators who are using natural gas as their basic electricity generating fuel. Per the generation licenses of the natural gas power generation units, the generators are committed to hold on an amount of reserves of an alternative fuel (oil/diesel) for the electricity generation.

The standard contracts of demand crisis management financing mechanism are signed between the Suppliers and Eligible Customers (Industries). Per RAE's decision 334/2014 after Transmission System Operator's declaration of the system (NNGS) at an Emergency Level, the TSO must cover (to finance) the full cost of the management of demand crisis of every supplier.

In December 2016, Greece was experienced electricity supply constraints mainly due to unprecedented unavailability of lignite generation, and extreme weather conditions that increased the domestic demand for electricity supply. Therefore, natural gas electricity generation units called by the TSO (ADMIE) to cover the excessive demand.

On December 19th, 2016 at time 20.46, the Operator declared the transmission system at an Emergency Level (Alert Status 1), under the terms of the Emergency Plan in accordance with Regulation No 994/2010 of the European Parliament and of the Council concerning measures to safeguard security of gas supply and in accordance with Chapter 10 of the NNGS Network Code.

Specifically, the Operator based on data about: a) the LNG reserves, b) the LNG cargo delivery program, c) the natural gas inflows into the interconnection points (borders) of the NNGS, and d) the rising domestic demand of natural gas, declared the system at the Emergency level 1 (Alert Status 1).

Under the Terms of the Emergency plan, the TSO informed the Natural Gas suppliers and the Transmission System operator of the electricity transmission system, ADMIE S.A.

ADMIE from his side informed the TSO (DESFA) about its estimation with regard the expected demand of natural gas by the electricity generation units of natural gas in the coming week.

On 21st December 2016, the TSO declared the system at the Emergency Level 2 (Alert Status 2). The TSO informed the Regulator about the situation submitting the estimated (im)balance of Demand and Supply of natural gas for the following seven days.

On 22nd December 2016, RAE after consultation with all the involved parties (TSOs and suppliers) decided to take crisis management measures:

a) To activate the measure of supply interpretability for the Eligible customers (but informing the Eligible customers at least 6 hours before the interruption and limiting the supply of gas to the eligible customers not less than 60% of their daily demand).
b) To activate the choice of the use of the alternative fuel for the electricity generation units of natural gas
c) To monitor daily the evolution of demand - supply balance

On 26th December 2016 with the delivery of a new LNG cargo at the LNG terminal of Revithoussa, the TSO declared the end of the status of the natural gas system at Emergency levels.

4.5 Conclusion.

In 2015, Law 4001/2011 (implementation of Gas Directive 2009/73) was amended by Law 4336/2015 which promoted the reform of the natural gas market and provided for: a) the full liberalization of the natural gas market in Greece and b) the removal of the monopoly power in the natural gas supply from the existing EPAs in the three main distribution areas in Greece. Per the Law 4336/2015 by 1.1.2018 all customers in Greece become eligible and have the right to switch suppliers. The transition period to the new market organization started in 2016 (transition period 2016 -2018). In 2016, Law 4414/2016 clarified further the Roadmap for the reforms of the natural gas market to meet the Gas target model criteria. More specific:

Unbundling: Legislation will be amended, further facilitating the unbundling process: a) of the natural gas TSO (DESFA SA) by DEPA and b) the regional natural gas retail corporations (EPAs) - separation of the ownership and operation of distribution systems from retail operation activity. Separation of EPAs from DEPA. RAE is working for the completion of this process. These actions will lead to the development of a wholesale market.

Strengthening the wholesale market by Opening the Retail market: decision on the free operation of the retail suppliers on the Greek territory meaning the termination of geographical defined areas of operation, and of exclusivity right (Law 4336/2015). The transition period to the new market organization started in 2016 (transition period 2016 - 2018).

Expected state of wholesale market operation in 2017

Based on the assessment of the current state of wholesale market functioning and considering the key drivers towards improved wholesale market functioning, it is expected that the Greek gas wholesale market will not reach to the Gas Target Model by 2017. But, there will be several improvements both in capacity market and product market liquidity. These improvements will be the result of: a) capacity auctions through RBP regional trading platform for the Interconnection entry point into the natural gas Greek system in Sidirokastro (Greece-Bulgaria border), b) the spare capacity available for trade in Agia Triada (LNG terminal in Revithoussa interconnection point), c) the operation of a balancing platform by the Greek TSO where both DESFA and shippers will trade natural gas and they will balance their positions (demand-supply).

To sum up, although the Greek gas market has not developed an intra-day market, a day ahead market and a forward market yet, the Greek gas market has developed a well- diversified supply structure. Currently, the Greek market has three supply routes with the prospects to add three additional supply routes and sources of natural gas (i.e. IGB, TAP, LNG terminal in Northern Greece). The increasing number of supply routes and sources indicate a high potential for competition to develop in the domestic wholesale market. With the operation of TAP pipeline in the year 2020 the Greek market will also be connected to the Italian market thereby allowing more trading of natural gas and the entrance of new suppliers into the market. By that year with the full implementation of the Network Codes, the Greek gas market is expected to reach the Gas Target Model.