2016 National Report to the European Commission

(Covering the period 01.01.2015 – 31.12.2015)

Regulatory Authority for Energy (RAE)

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1. Foreword

For the energy sector 2015 was a crucial year, as fundamental changes begun to take shape and formulate the future industry structure in both electricity and natural gas. In the regulatory front, RAE was in the process of reviewing the regulatory framework that would effectively support the changing environment, designing the proper mechanisms that would implement the above changes, always in full alignment with the European Directives and Guidelines.

In the electricity market among the most important developments in the wholesale market were the harmonization efforts towards the European Target Model (which was advanced to the point of adopting its requirements with a concrete timetable), the implementation of a Cost Recovery Mechanism (with more stringent criteria) and the introduction of a Transitional Capacity Assurance Mechanism. In the retail market, the formulation of NOME type auctions begun to be planned, a fundamental development for the further liberalisation of the market. At the same time, RAE undertook several initiatives and regulatory measures to foster liquidity in the domestic energy market and to help create a financially viable environment, through effective management of the credit and market risk, created by accumulating consumer debts (unpaid bills) and the Market Operator's lack of liquidity, in a very adverse economic and market environment.

In the gas market, Law 4336, introduced the unbundling of the distribution activities from the suppliers by January 1st, 2017. After a successful co-operation with the Italian and the Albanian energy regulators, starting in 2013, RAE completed in 2015 the initial Certification procedure for certifying TAP as an Independent Transmission Operator (ITO) of Natural Gas and also took a Decision for the exemption of TAP. RAE approved the updated General Guidelines (written together with EWRC) for the capacity allocation management of ICGB for the first Market Test to take place.

As a new challenging era is emerging and new priorities and governmental directions and decisions are shaping up, RAE will remain dedicated to its main objectives: to maintain the necessary security of the country's energy supply, both physically, and economically, and ensure affordable energy costs for the national economy and the Greek consumer, and, at the same time, to prepare the Greek energy market to participate, in a smooth, organised and efficient manner, in the ongoing integration process of the single European energy market.

Dr. Nikolaos G. Boulaxis

President

2. Main developments in the gas and electricity markets

2.1 Electricity

Although no changes in the rules of the wholesale mandatory pool were introduced during 2015, the supplementary mechanisms (Cost Recovery Mechanism and the Transitional Capacity Assurance Mechanism) which exerted a substantial impact on market outcomes, were revised in crucial aspects, in an effort to yield more competitive outcomes.

At the same time, RAE is proceeding with a power market restructuring design and, especially, with the design of the implementation of Target Model in Greek wholesale market, based on the European Directives and Guidelines.

Regarding the fuel mix, the increase in consumption in 2015 and the significant decline in imports in the second half of the year, boosted electricity particularly from natural gas plants. More specifically, the lignite production showed a further substantial fall in 14,5% (3290 GWh) by 2015 compared to 2014, down to 19.4 TWh, compared with 22.7 TWh in the previous year. This decline could have been even greater if imports were not limited due to capital controls (which were imposed at the end of June 2015), and which resulted in the closing of the output gap from domestic lignite plants and natural gas plants. The contribution of RES was 24% (compared to 17.9% in 2014) of the total energy, although the rate of building new RES capacity had dropped drastically, due to changes in the legal framework during 2013 and 2014.

In the retail market, PPC also remained by far the dominant supplier, as it held almost the entire retail market (99.5% of the total number of customers and about 97.6% of total electricity supplied). Although 10 other suppliers were active, the switching rate remained very low.

The growth of customer liabilities against their electricity suppliers continued in 2015 (PPC's estimated unpaid receivables of 2 billion at the end of 2015), reflecting the difficulties faced by consumers during the deep economic recession.

Regarding the non-interconnected islands (NII), 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.

2.2 Natural Gas

No structural changes of the gas market took place during 2015. However, in 2014 the Greek State announced an ambitious plan for the reform of the market. The plan included, among others, changes at the level of the wholesale market, but, mainly, significant changes in the organization and operation of the retail market. The latter included a gradual termination of the concession that the three existing distribution and supply companies (EPAs) enjoy in the regions in which they operate, as well as an immediate reform of the supply regime for the rest of Greece, with an emphasis on setting eligible as many customers as possible.

Law 4336/2015 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. It 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 the Law 4336/2015, the old Licenses for Supply & Distribution which were granted to EPAs will be abolished in 2017. The Law 4336/2015 also specified the timing of the separation of the distribution activities and supply of gas to existing EPAs and DEPA and 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.

In the meanwhile, in order to enhance competition and strengthen the liquidity of the gas market, the Competition Commission, in late 2012, with the active participation of the Regulator, established a gas release program. DEPA committed to offer volumes of natural gas (10% of the quantity supplied to its customers during the previous year) through electronic auctions to the market. Several amendments to the gas release program were introduced in 2015, especially following RAE's suggestions regarding volumes, duration, auction price, delivery etc, that were important so that the gas release program can indeed offer better priced natural gas to the other players of the greek gas market.

With its Decision 394/2015, RAE in co-operation with the Regulatory Authorities of Italy and Albania, proceeded to initially certify TAP (Trans Adriatic Pipeline) as an Independent Transmission Operator of Natural Gas.

In the purely regulatory form, RAE initiated the procedure for a third revision of the Gas Network Code, which took place in 2015. A security of supply levy payable by all gas consumers was introduced, meant to finance the costs associated with the establishment of an incentive scheme designed for demand response by large customers and the readiness of availability of liquid fuel at power stations with dual fuel capability, in case of a gas security of supply crisis.

For what concerns DESFA, during 2015 the transaction 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, in order 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.

3. Regulation and Performance of the Electricity Market

3.1 Network Regulation

3.1.1 Unbundling

3.1.1.1 Certified Transmission System Operator - ADMIE S.A.

ADMIE S.A., the Independent Transmission Operator (ITO) since February 2012, 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. According to the Energy Law 4001/2011, the ITO model has been applied in the Greek market for the Transmission 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 Operator (ITO). ADMIE 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 2015, despite Government's plans to privatize and/or terminate fully PPC ownership of ADMIE.

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 2015.

3.1.1.3 Accounting unbundling

According to the provisions of the Energy Law 4001/2011 and the European Directive 2009/72, integrated undertakings 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

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 performance1. 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) F[1].

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.

In this context, the role of the Regulator includes the following:

- Setting, per regulatory review period, of the regulated service quality dimensions, the corresponding overall and individual minimum quality standards, as well as the respective penalties/rewards, 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.

Until the Code is finally enforced, 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

[1] 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.

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), on December 2015. The results of the second public consultation on the review of the Distribution code are expecting to be 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 through guaranteed indicators with automatic compensation for customers.

3.1.2.2 Network tariffs for connection and access

Network access tariffs in Greece are of the ‘Postage Stamp’ type, with the ‘G’ component being equal to 0% and the ‘L’ 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 and DEDDIE, respectively).

Developments regarding network company revenue regulation methodology in 2014/2015.

In June 2014, following extensive public consultation, RAE approved the new methodology for setting the TSO’s allowed revenue (Decision no 340/214). The most critical changes, in comparison with the previous cost-plus methodology, are:

- A multi-year regulatory period (3 years for the interim period 2015-2017, and 4 year period thereafter).
- Calculation of the TSO’s Allowed Revenue based on real terms.
- Detailed methodology for the calculation of Return on Capital Employed based on real pre-tax WACC.
- Calculation of depreciation using economic, instead of accounting, asset lives.

- Smoothing of revenues within and between regulatory periods, in order to minimise the impact of fluctuations to consumers.
- 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.

Furthermore, during 2014, RAE appointed a consultant in order to review the methodologies for setting user tariffs for access to transmission and distribution networks (connection and usage tariffs). Final results were delivered late 2015. Main objectives of this work were:

- Evaluation of existing methodologies regarding Allowed Revenue for Networks, according to international experience and recommendations on the methodology to be applied in Greece.

- Comparative analysis of the international practice and the Greek current practice, relating to methodologies for tariff structures (usage and connection charges) and recommendations on the methodology to be applied in Greece.

The process for setting the required revenue (applying the previous methodology) and the network access tariffs for 2014 was completed in April 2014. For the year 2015, the annual transmission cost and the required revenue are as follows:

Table 1. Annual Transmission Cost and Required Revenue for 2015 in 000 Euro	
	2015
Operating Expenses	82.000
Annual Depreciation	56.000
Return (RAV*r)	116.653
Total Cost/ Allowed Revenue	254.653
Total Required Revenue	215.108

The approved return was based on the previous 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 the Transmission Use of System (TUoS) tariffs for HV customers is set out in the System Operation Code, while the one for customers 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 on the basis of the contribution of each class to the transmission system summer and winter peak demand.

For the purpose of calculating TUoS charges for customers connected to the distribution network, the methodology, as set out in the relevant Manual, further specifies the following:

For the purposes of TUoS charging, the following four (4) customer categories apply:

Medium Voltage (MV), Residential, Residential with Social Tariff (KOT), 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).

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 on the basis of 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 on the basis of the connection capacity (kVA) given the lack of metered demand (MW), whereas the remaining is recovered through a simple €/MWh energy charge.

According to the above mentioned methodology, RAE approved the following tariffs for 2015:

Table 2. Regulated Tariffs applied for the use of the transmission system in 2015

Consumers Category	Capacity charge	Energy charge (cents €/ kWh)
Large Consumers HV	22.623 €/MW /per year	-
Consumers MV	1.236 €/MW Peak time/ month	-
Households LV,	0,14 €/kVA per year	0,541
LV – Vulnerable customers	-	0,602
LV others	0,55 €/kVA per year	0,489

Note: Taxes not included, VAT 23%

3.1.2.3 Distribution use of system tariffs

There is currently no formal methodology set for the calculation of the allowed distribution revenue, given that the Distribution Network Code (which will include the methodology for estimating the annual distribution costs) has not been adopted yet, and is expected to be finalised and approved during 2016. As a transitional measure, the methodology applied is the one that was in effect for 2014 for the transmission system.

In accordance with its Decision 840/2012, RAE approved the total Required Revenue for Distribution Network (for the Operator and its parent company, as owner of the network assets) for 2015 (RAE Decision 454/2015) as follows:

Table 3. Annual cost and Required Revenue for 2015

	PPC S.A (the owner)	DEDDIE S.A	Total
operating expenses		427.412	427.412
annual depreciation	129.911	6.429	136.340
Return (RAV*r)	203.801	17.625	221.426
Other (rent)	-11.000		-11.000
Total Cost/Allowed Revenue	322.712	451.466	774.178
Total Required Revenue	318.093	447.743	765.836

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): 7.7%.

Out of a total required revenue of €765.836m, €65m were set to be recovered by MV connected consumers and the remaining by LV connected consumers. Distribution network cost is allocated between MV and LV connected customers on the basis of the contribution of each class to the distribution network summer and winter peak demand.

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

For MV customers, 50% of the cost is recovered through a capacity charge and 50% through an energy charge. For residential customers, 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 System unit charges for Distribution in 2015, per customer category, are presented in the following table 4. The unit capacity charge is applied on the customer's subscribed demand for LV customers and on the Monthly Maximum Demand registered at daily peak-hours for the MV customers. The unit energy charge is applied to the metered energy, adjusted for the average power factor (assumed to be equal to 1 for costumers without reactive power metering).

Table 4. Regulated tariffs applied for the use of the distribution system

Consumers Category	**Capacity Charge.** **(fixed charge per unit of consumption)**	**Energy charge** **(cents €/kWh)**
Consumers MV	1.125 €/MW	0,29
Consumers LV (over 25 kVA), based on the calculation of the maximum supply and taking into consideration the non used power	3,85 €/kVA 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	3,27 €/ Kva Agreed and charged per year	1,9
Consumers LV	0,56 €/kVA Agreed and charged per year	2,14
Consumers (vulnerable customers)	-	2,37
Others LV (maximum 25 kVA)	1,50 €/kVA	1,9

(Taxes not included VAT 23%).

3.1.2.4 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. According to the provisions of Law 4001/2011, a detailed pricelist is to be submitted by the TSO to RAE for final approval.

3.1.2.5 Distribution network connection tariffs

A methodology for setting connection tariffs has not yet been approved by the Regulator. The methodology is envisaged to be part of the Distribution Network Code, which is still in preparation, and is expected to be finalised and approved by RAE, after conducting public consultation, during 2015.

3.1.3 **Cross-border issues**

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

In 2015, there was a significant progress in respect to the interconnection capacity available for trade. As a result, the total import interconnection electricity trading increased by 15,29% in respect to the total imported volumes of the previous year. The total export interconnection electricity trading increased by 68% in respect to the total exported volumes in the previous year. However, the total imported volumes (11,12TWh) were much larger than the exported volumes in real terms (1,76TWh). The Net trade balancing was - 9,3TWh in 2015 comparing to the net trade balancing equals to - 8,8TWh, in 2014.

Table 5: Interconnection power capacity and trade in 2015						
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 (TWh)	468	197	196	39.	865	1.765
Imported Energy (TWh)	751.	1.765	2.290	4.614	1.943	11.129

The significant increase in imports was mainly due to the lower regional electricity prices especially in the first semester of 2015. The scheduled maintenance of the DC interconnector in the border Greece – Italy that took place during the months October to November, 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) balance had already increased significantly the previous years (+319%), from 2.1 TWh in 2013 to 8.8 TWh in 2014.

Table 6 presents the monthly evolution of the import interconnection trading in 2014 and 2015 and table 7 the distribution of interconnection trading in 2015 and its evolution compared to 2014.

Table 6. Monthly evolution of the import interconnection trading 2015 & 2014				
Total import interconnection trading (MWh)				
	2014	**2015**		
January	497,402	1,248,828		
February	391,532	951,577		
March	755,354	1,249,082		

April	533,212	1,042,495		
May	681,667	990,553		
June	746,006	983,489		
July	1,068,206	939,518		
August	1,130,011	1,003,102		
September	884,476	928,903		
October	861,433	724,582		
November	1,141,145	586,631		
December	1,166,455	714,818	**Change rate (%)**	
Total	**9,856,899**	**1.1363.578**	**15,29%**	

Table 7. the distribution of interconnection trading									
Import share									
Turkey		**Albania**		**FYROM**		**Bulgaria**		**Italy**	
2014	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**
4,48%	6,61%	19,26%	15,53%	21,77%	20,15%	40,06%	40,61%	14,43%	17,10%

Imports in real volumes from all countries, increased significantly. But, the import shares of the interconnection points in total imports remained unchanged, in 2015. The highest percentage share observed in the interconnection with Bulgaria, it was 40,61%. Imports from Turkey recorded the lowest (but increasing) percentage imports share by 6,61%, while imports from FYROM, Albania and Italy percentage shares in total imports were 20,1%, 15,5% and 17,1% respectively.

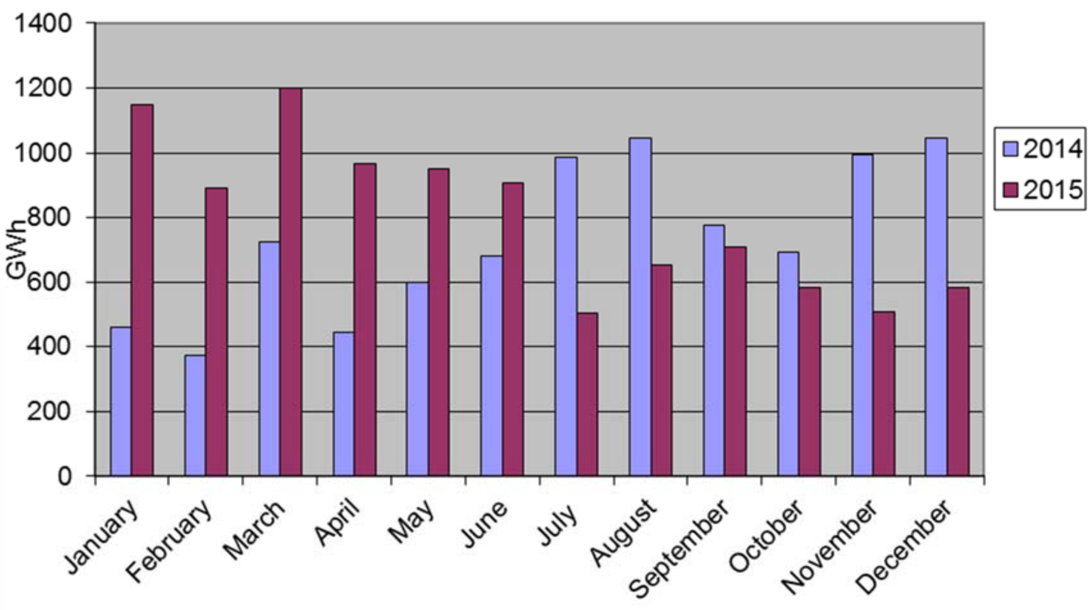
Exports increased from 1,05 TWh in 2014 to 1,7TWh in 2015 (68%), Tables 8 & 9

Table 8. Total export interconnection trading (MWh)			
	2014	**2015**	
January	41668	98336	
February	23535	70952	
March	32493	50191	
April	94329	72688	
May	82712	39974	
June	68011	71275	
July	73212	438313	
August	97889	347476	
September	114150	210450	
October	171813	131062	
November	145252	82932	
December	106281	152629	**Change rate (%)**
Total	1051345	1766278	68,00%

Table 9. Export share									
Turkey		**Albania**		**FYROM**		**Bulgaria**		**Italy**	
2014	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**
70,30%	26,52%	5,96%	11,15%	3,75%	11,14%	0,18%	2,23%	19,81%	48,96%

Overall, the trading volume in all borders increased by 1.5 TWh (15%), with Italy having the higher percentage increase in 2015. The operation of the interconnection with Italy during the second half of 2013 was problematic (the repeated forced outages led to long periods of limited, or no availability of the interconnector) and this led to a major reparation procedure that took place during the first semester of 2014. During that time the interconnection was not available to the market participants, hence the interpretation of the above figures should account for that fact.

Figure 1. Monthly net imports during 2014 and 2015



The capacity allocation for the Italian borders, within the Central – South Europe (CSE) Region, is performed (since April 1st, 2011) by the Capacity Allocation Service Company (CASC S.A.), which also performs the capacity allocation functions for the 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 harmonisation 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 apply to the borders with 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. The Bulgarian Transmission Operator (ESO EAD) decided not to participate in SEE CAO; therefore, the Auction Rules approved by RAE remained unchanged in 2015. 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 2015.

At the border with Bulgaria, Common Capacity Allocation Rules are being applied since 2011 to the joint auctions for the allocation of the total 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 2015.

Regarding Turkey, the interconnection with Greece 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 for Albania and FYROM. 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 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 and 1/3 for the Greece-Turkey border. The main principles of interconnection congestion management rules in 2015 remained the same as in in 2014 and 2013, namely:

- Yearly, 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.

Daily PTRs are firm.

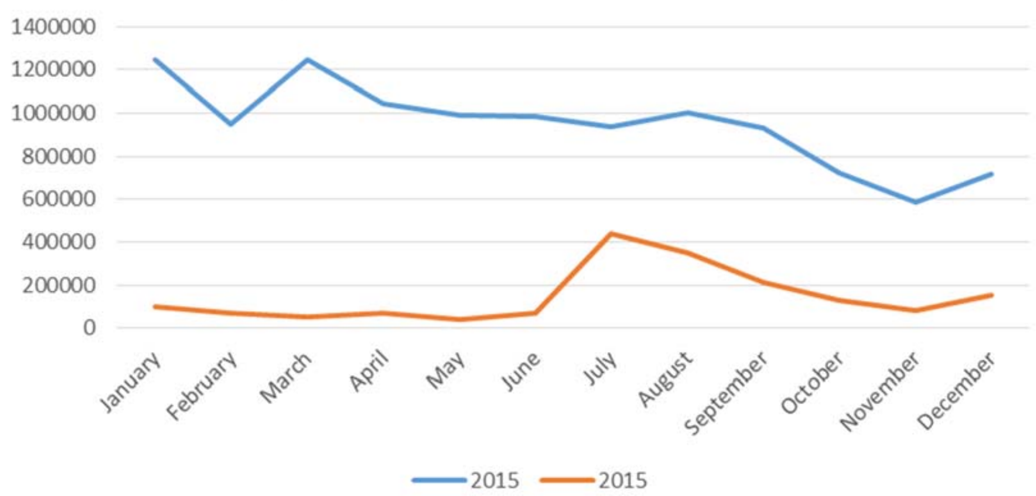
Under this scheme, during 2015 ADMIE managed capacity allocation at the interconnections and directions, as follows:

Table 10. 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 capacity.

Income from congestion management has been used for purposes complying with the provisions of the Article 16 of Regulation (EC) 714/2009 and its Annex with the Congestion Management Guidelines, namely to reduce transmission network tariffs. This is reflected in the relevant report that RAE publishes annually, as required by the same Regulation

Figure 2. Cross border electricity trading in 2015



3.2 Promoting Competition

3.2.1 Wholesale market

3.2.1.1 Description of the wholesale market.

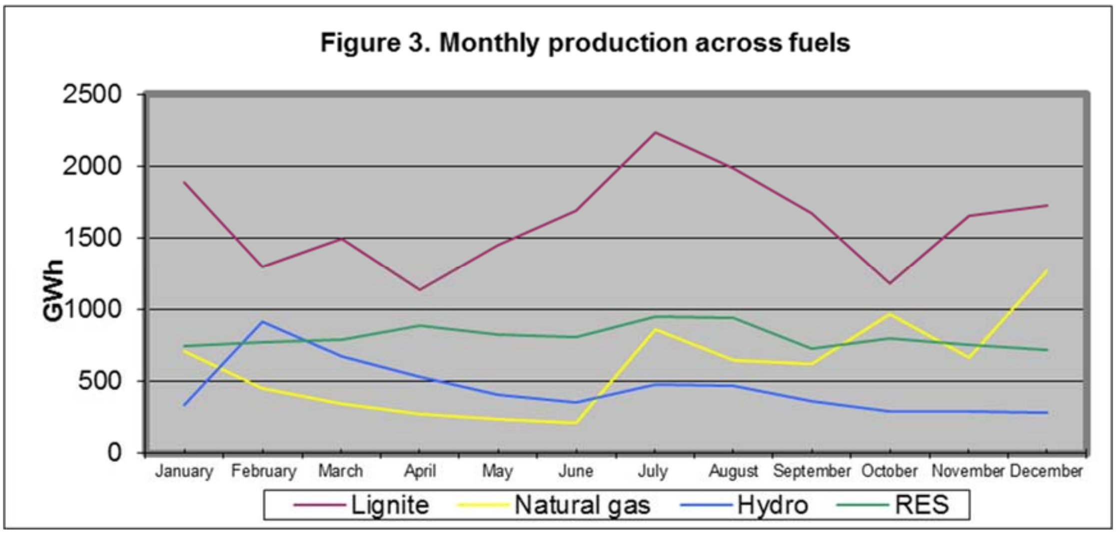
The Greek wholesale electricity market has been organised as a pure mandatory pool since its inception in 2005, so as to allow competition to emerge in a context with a severe constraint: no structural reforms were implemented with regard to PPC, the incumbent vertically integrated monopoly utility, such as plant divestments or consumer release, as elsewhere in Europe. In particular, the incumbent remained 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, in order 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 liberalisation, giving a strong signal for upcoming capacity shortages in the following years. The capacity certificates introduced in 2006 created incentives for new investment, which turned out to be adequate. More specifically, following the introduction of the 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 entered into commissioning status. 2014 saw only a small increase in capacity given the commissioning of a new PPC 155MW hydro plant (Ilarionas). 2015 saw an increase in installed capacity of natural gas plans from 4906MW in 2014 to 5751 in 2015 (a rise of PPC CCGT plans' installed capacity). For the same period RES saw only a small increase in capacity, from 4464MW in 2014 to 4594MW, in 2015.

Table 11. Installed Capacity by Producer/Fuel			
By producer/fuel	**Installed Capacity except RES 2015 (MW)**	**Installed Capacity except RES 2014 (MW)**	**Installed Capacity except RES 2013 (MW)**
PPC Lignite	4456	4456	4456
PPC Hydro	3173	3173	3018
PPC CCGT	2843	1998	1998
PPC OCGT	339	339	339
Elpedison CCGT	799	799	799

Heron II CCGT	422	422	422
Korinthos Power CCGT	434	434	434
Protergia CCGT	433	433	433
Heron I OCGT	148	148	148
Alouminion CHP	334	334	334
PPC Oil	698	698	698
Total Thermal+Large Hydro	14077,9	13232,9	13077,8
Renewables	4593,5	4463,6	4295,2
Total	18671,4	17696,5	17373,0

Table 12. Installed Capacity by Fuel			
By fuel	**Installed Capacity 2015 (MW)**	**Installed Capacity 2014 (MW)**	**Installed Capacity 2013 (MW)**
Lignite	4456	4456	4456
Natural Gas	5751	4906	4906
Oil	698	698	698
Hydro	3173	3173	3018
RES	4594	4464	4295
Total	18671,4	17696,5	17373,0

Table 13. Installed Capacity incl RES					
Installed capacity and production by producer and by fuel, in 2015	**Installed capacity (MW)**	**Total annual production (GWh)**	**Share in produced volume (%)**	**Share in produced volume including RES (%)**	**Capacity factor (%)**
PPC Lignite	4456	19417	58,49%	46%	49,6%
PPC Hydro	3173	5390	16,24%	13%	19,3%
PPC CCGT	2843	4424	13,33%	10%	17,7%
PPC OCGT	339	0	0,00%	0	0
Elpedison CCGT	799	1142	3,44%	2,7%	16,3%
Heron II CCGT	422	432	1,30%	1,0%	11,7%
Korinthos Power CCGT	434	623	1,88%	1,5%	16,3%
Protergia CCGT	433	601	1,81%	1,0%	15,8%
Heron I OCGT	148	145	0,00%	0	11,1%
Alouminion CHP	334	1163	3,50%	2,7%	79%
PPC Oil	698	0	0,00%	0	
Total Thermal+Large Hydro (1)	14077	33196	100%	78 %	27%
Total RES (Grid + Network) (2)	4594*	9745		23%	24%
Total (1+2)	18.671	41.822		100%*	
To the closer integral					
RES (2014) 4940 including islands (2014 national report)					



However, early projections for strong and prolonged growth of 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 supplementary mechanisms were refined so as to lead to more competitive market outcomes and reduce operational inefficiencies that had emerged. In essence, 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 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-minimisation 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 into bilateral financial contracts (CfDs), but physical delivery transactions are constrained within the pool and related contracts do not exist. A cap of 150 €/MWh has been imposed on all generators' offers.

The following rules or supplementary mechanisms, which exerted a substantial impact on market outcomes, were revised during 2013 and 2014 in crucial aspects so as to yield more competitive outcomes:

- 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, as long as 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 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 as a way 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 RAE evaluated the implications of the mechanism abolition and with its Decision 392/2015, 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 2015.

Provision of Balancing Services.

Balancing is not performed through a separate balancing market, but as an extension of the day-ahead market, through the Imbalance Settlement Mechanism, according to 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, taking into account 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 realised values of the stochastic variables and corresponds to the "Market Clearing Price" (i.e. uniform price).
- Moreover, a cost recovery mechanism is included, so as to ensure that generators will receive at least their marginal cost whenever they operate. The objective of the imbalance mechanism setting is to minimise 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.

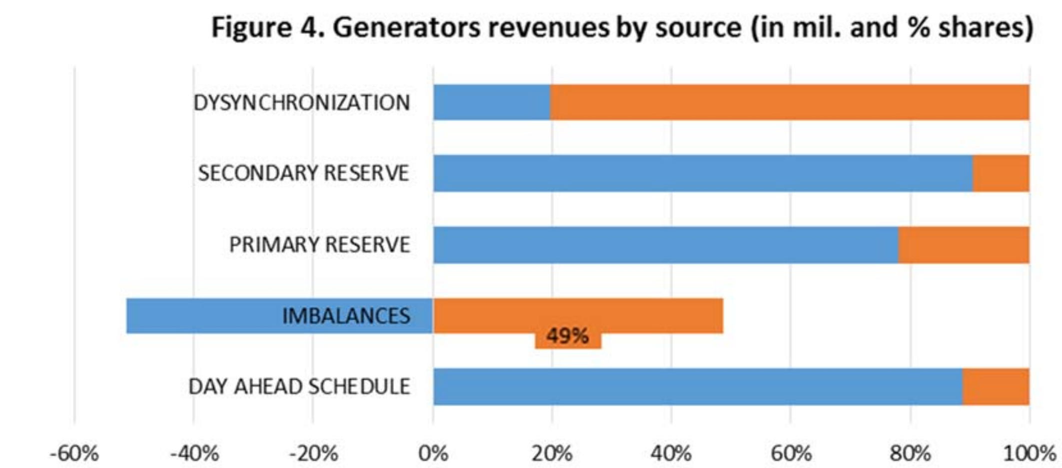
In view of the EU Target Model implementation, RAE is elaborating the necessary market design changes, including the introduction of intraday and balancing markets.

Market Settlement

2015 was the fifth year of the implementation of the market design that allowed for the settlement of imbalances, and the second year of the reform package for the wholesale market, as described above. The remuneration through the day-ahead market represented 95% of generators' cash-flows, as compared to 77% in 2014 and 63% in 2013. More specifically, the generators' annual revenues from the day-ahead market amounted to €1,77 billion, while ex-post settlements amounted to € 92 million. Hence, the turnover of the wholesale market reached €1,86billion (€2.7 billion in 2014, €3.02 billion in 2013).

The supplementary Cost Recovery Mechanism was zero 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. Besides the abolition of this mechanism in the second half of 2014, an important parameter was the more efficient operation of gas units. Primary and secondary reserve payments amounted to €1,3 million and "desynchronization" payments amounted to €44 million.

For PPC, the day-ahead market reflected almost 100% of its income as a producer (79% in 2014), while for IPPs the corresponding percentage was 68% (44% in 2014). Hence, ex-post settlement amounts were still crucial for the viability of the new independent plants in 2015, contributing another 32% 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 2015.



	DAY AHEAD SCHEDULE	IMBALANCES	PRIMARY RESERVE	SECONDARY RESERVE	DYSYNCHRONIZATION
PPC	1,569.19	-25.73	0.08	1.10	8.65
IPPs	199.72	24.35	0.02	0.12	35.42

Market Volume

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 51,4TWh in 2015 (50,2TWh in 2014), reflecting a marginal increase of 2,2% relative to 2014.

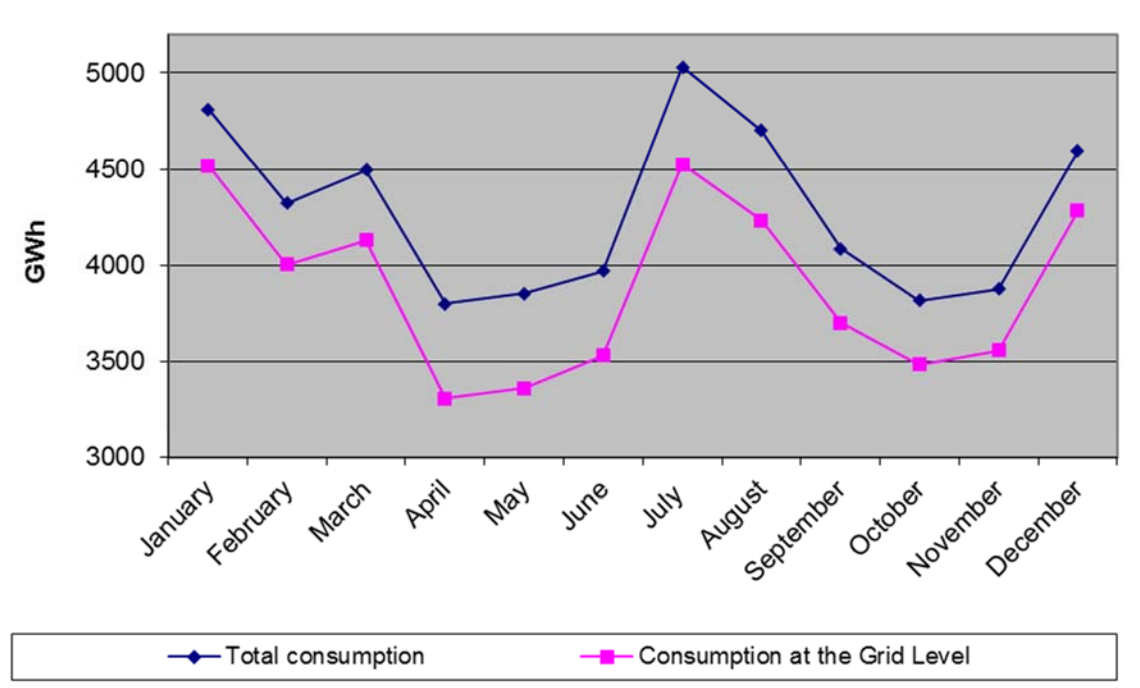
Figure 5 displays the demand fluctuations at the aggregated monthly level, both based on grid metering and, also, by taking into account the PVs connected to the network. A futures market has not been developed yet, while OTC trading has not been activated either.

Table 14. Monthly electricity Demand

	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**	Total
Total consumption	4810	4321	4496	3800	3853	3971	5032	4700	4085	3816	3876	4595	51355
Consumption at the Grid Level	4518	4004	4130	3309	3363	3530	4527	4234	3700	3484	3558	4284	46641

Total consumption 2014 (GWh)	4469	3976	4121	3681	3789	4085	4906	4718	3911	3898	4123	4550	50227
Total consumption change 2014-2015 (GWh)	341	345	375	119	64	-114	126	-18	174	-82	-247	45	1128
Total consumption change rate (%)	7,63	8,68	9,10	3,23	1,69	-2,79	2,57	-0,38	4,45	-2,10	-5,99	0,99	2,25

Figure 5.Monthly Electricity Demand



The installed capacity at the end of the year, as well as the annual production shares across fuels and imports, are presented in Sections 3.2.1.2 and 3.3.1.

3.2.1.2 Monitoring market shares

Regarding the market structure, PPC retained in 2015 its dominant position. 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 respect to the installed capacity the incumbent's market share was 81,7%. in terms of conventional technologies (thermal and large hydro) in the interconnected system. The incumbent's (PPC's) market generation share was 70%, if renewable generation is also taken into account. Additionally, the incumbent's installed capacity generation share was 60,7% if renewable capacity is also taken into account. It should be emphasized that in the generation sector, a less concentrated structure has been emerging gradually since 2010, when two new IPP units entered into commercial operation.

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, will be 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. Summarising, 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 (2015-2024), 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 materialisation 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 2015 in the interconnected system amounted to almost 90% of domestic production (excluding RES), while independent gas producers achieved only a 10% share, as the newly-added PPC's Aliveri V further shrunk IPP generation. The net installed capacity and the produced volumes per fuel and producer in 2014, 2015 are depicted in the following Figures (see also Section 3.3.1).

Figure 6. Net installed capacity per producer and fuel (MW and %)

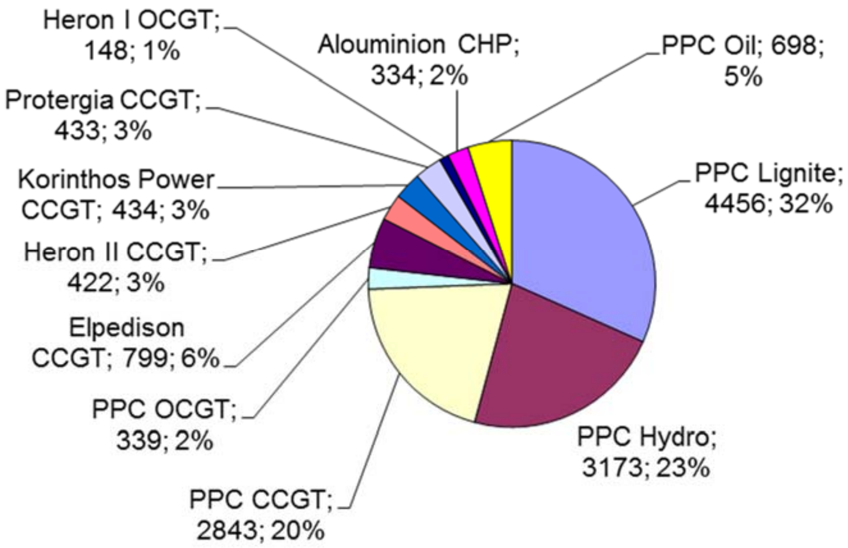
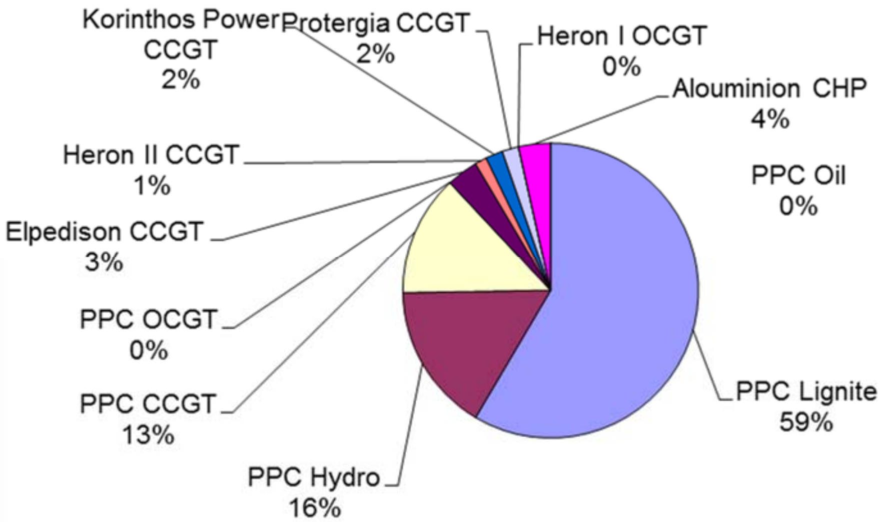


Figure 7. Annual production per producer and fuel (%)



The HHI index for the wholesale market in 2015, a measure of market concentration, attained the value of 7820 in terms of volume production and 6804 in terms of installed capacity, and 6624 in terms of installed capacity; these values are to be compared with 8091 and 6624, respectively, in 2014. We should underline that the calculation of these indicators did not take into account RES generation and RES installed capacity, the main argument is that RES did not participate in the market under the implemented rules of feed in tariff (FiT) and of access priority, in 2015. Market concentration is decreasing further if we take into account the net imports volume, in 2015.

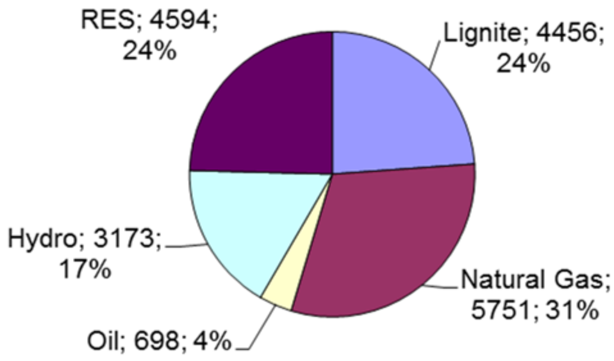
In 2015, the strongly increased concentration in terms of volume vividly illustrates the shrinkage of the production by the independent producers, in an effort to limit the financial losses suffered under the current conditions. Of course, it should not be overlooked that a long way has been travelled 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.

Table 15. Share in produced volume per Group (%)	
PPC	88,06%
Elpedison	3,44%
prot+aloum+kp	7,20%
Heron	1,30%
RES not included	
Year	**HHI index (production)**
2015	7820
2014	8091
2013	6553

Table 16. Share in installed capacity by Group (%)	
PPC	81,75%
Elpedison	5,68%
prot+aloum+kp	8,53%
Heron	4,05%

Table 17. Market Share Installed Capacity & HHI Index, 2015	
2015	**PPC**
Share in installed capacity (except RES)	81,7%
Share in total installed capacity	61,6%
Year	**HHI index installed capacity**
2015	6804
2014	6624
2013	6597

Figure 8. Installed Capacity by fuel (MW and %)



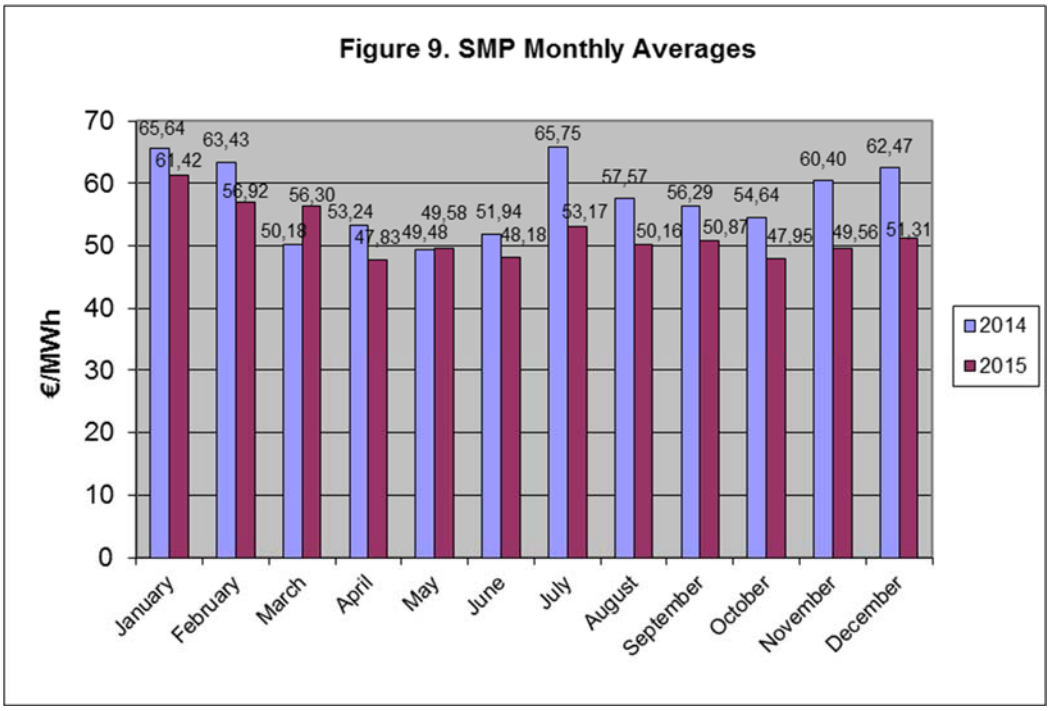
3.2.1.3 Price Monitoring

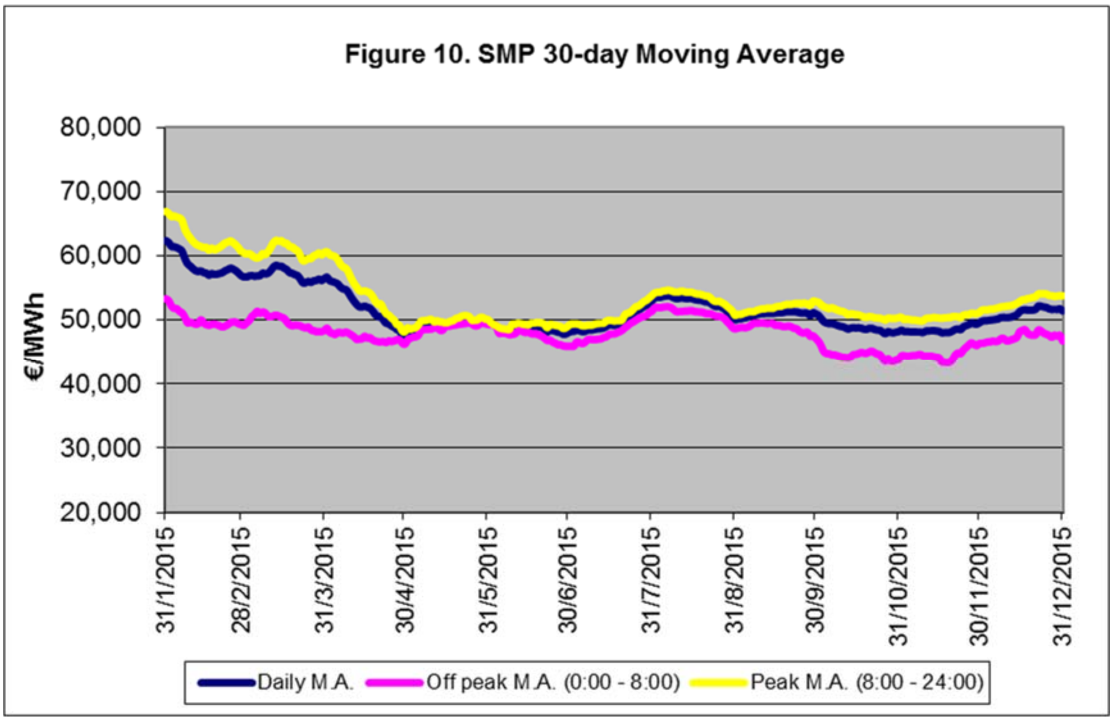
The average System Marginal Price (SMP) in 2015 amounted to 51.93 €/MWh recording a noticeable decrease (-9,8%) compared with the previous year 57.56 €/MWh in 2014 and 41.47 €/MWh in 2013. For the correct interpretation of this upward trend, it is important to clarify that it constitutes a partially correction of the SMP, more realistically reflecting the variable cost of the units dispatched in the DAS. This is because, up to September 2013, SMP levels had been strongly depressed, deviating systematically and significantly from the actual variable costs of production units.

Focusing on the monthly fluctuations, which are depicted in Figure 9, it is noteworthy that the average SMP showed quite normal behavior in 2015 ranging between 47,83 € / MWh in April and 61,42 € / MWh in January. The maximum monthly level of SMP was primarily due to weather conditions, as in January (especially the first ten days) which was characterized by snow and frost. In general, the change of SMP compared to upwards of 2014 levels, ranging on a monthly basis between -19% and 12%, characterized in that the second half of the year, the price of SMP downward trend was noticeable (less change -10% in September and greater variation -19% in July), reflecting the increased operation of coal plants and natural gas, the fuel which the latter has continually and lowest price.

The monthly fluctuations 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 similar to that of 2014, and the total annual participation in the DAS showed a slight increase of 4.85%, reaching 20%, is therefore considered quite smooth compared to 2013, year in which, due to regulations of the State, the RES had sharply increase, doubling ultimately their participation in the DAS. The high monthly level of SMP that recorded in January 2015 followed a downward trend in prices reached 47,83 € / MWh in April. The decline in July was interrupted prices, as domestic units were invited to cover the production deficit caused by imports, maintaining, however, a steady downward trend, with slight variations, until October. Strengthening of SMP in the last 2 months of 2015 reflects issues in availability of PPC units, such as comprehensive maintenance of the lignite units (Ag. Dimitrios 2 Ag. Dimitrios 4), sluggish production RES and limited hydropower production.

The variability of the hourly levels of SMP, as reflected in the standard deviation showed a significant decrease, recording average daily 7,28 € / MWh in 2015, compared with 11,14 € / MWh and 13,17 € / MWh in the years 2014 and 2013, respectively. This reflects the more homogeneous variation of prices around the levels at which stood at 2015. These characteristics are reflected in the duration of SMP curve. It is indicative that the SMP exceeded 80 € / MWh for only 1% of the hours distribution (compared with 8% of hours in 2014 and 7% of the hours in 2013), while in general, the hours during which it received greater than 55 € / MWh have decreased significantly (almost halved in compared with 2014). Generally the SMP was determined mainly from lignite plants (58%) and then by natural gas units (22% of the total hours of the year), while less frequently than imports (11%), exports (6%) or hydro (3%). 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

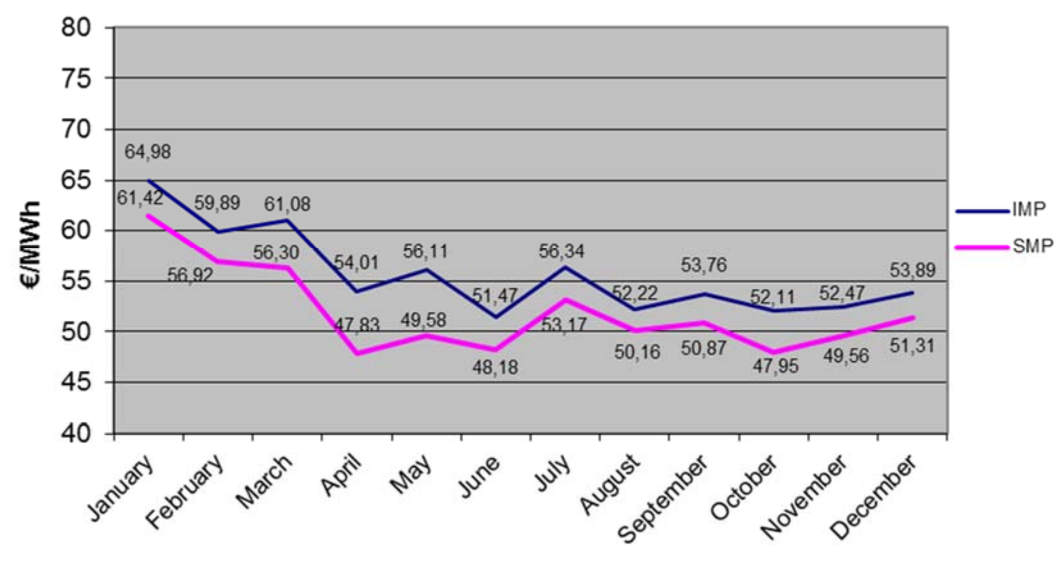




Regarding extreme hourly rates, the SMP touched the ceiling of 150 € / MWh in just 10 hours of distribution, particularly in February, as there were no extreme conditions which marked, even temporarily, potential power deficit. Such cases were observed in previous years, in particular for thirty nine (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, ie 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.

It is noteworthy that the frequency of zero values significantly reduced in 2015 to just 5 hours distribution versus 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. 80% of these zero values corresponding to 4 hours of distribution were observed in the months of September and October, and whenever there were particularly high imports in the order of 1.107,75 to 1.713,38 MWh MWh, covering up to one third of demand for those hours (namely coverage ranged from 24.55% to 37.69% 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.

Figure 11. Imbalances price - SMP monthly variations



3.2.1.4 Monitoring of transparency

Following the transparency requirements posed by the Codes, the TSO and the Market Operator publish on a daily basis 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-minimisation algorithms that each operator solves. In this context, ADMIE publishes on a daily basis 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 dayahead 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-optimised), 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, so as 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 standardised format was finally approved by RAE in February 2013. This report is uploaded on LAGIE's website, on a monthly basis, 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.

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 with regard to market participants' registration process and data collection. More specifically, under the EU regulation 1227/2011 on wholesale markets integrity and transparency, market participants entering into 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.

According to 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, in order 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) in order 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 in order 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 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).

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.

3.2.1.5 Monitoring of effectiveness of market opening and competition

As already mentioned, the most important barrier to market opening and competition is the structure of the Greek market characterized by the dominance of PPC in the generation market, and specifically in hydro and lignite generation, as indicated in Section 3.2.1.2 and Section 3.3.1. It should be noted that throughout the deregulation process, since its initiation in 2000, the market design has evolved, not independently of the underlying market structure, but in response to its asymmetries or inefficiencies, intending to alleviate the distortions arising from structural features. The challenging issues that continued to arise in the domestic electricity market throughout 2015 emphasised 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 vertically-integrated companies (with generation and supply portfolios), other than PPC.

Vertical structures would enable firms to better manage risks, through balancing their production and retail activities, with consumers being a physical hedge, hence, allowing transfer of costs and creation of value across the value chain.

In 2011, RAE initiated an assessment of market design modifications, with the aim to stimulate structural market changes. These changes included Virtual Power Plant auctions, or more regulated measures, similar to the NOME approach applied in France. The common objective in such measures, irrespectively of their technical parameters, would be to allow generation portfolio diversification and reduction of average cost of supply for IPP generators, in order to facilitate their entry into the retail market and, hence, to enhance consumers' options and potential benefits. At the same time, RAE assessed market restructuring options, so that the local market becomes compatible with the Target Model framework (in particular, the market coupling with Italy). In 2014, excess capacity, to be assessed against declining demand levels, continued to be an issue. Overall, it is notable that the total installed capacity of gas plants exceeded that of lignite plants. In addition to contributing to security of supply, the new gas capacity is expected to play a significant role in supporting the large-scale penetration of renewables through its flexibility, alleviating the strong fluctuations of intermittent output (mainly wind) and, also, entailing the ramping rates required to address the sudden elimination of solar energy in the evenings (sunset effect). These elements were crucial for the revision of the capacity mechanism that RAE implemented in July 2013, but also for further plans to introduce a new capacity remuneration mechanism. Below we discuss the progress achieved in 2015 on the above market restructuring and other issues regarding the wholesale electricity market.

Regulatory progress in wholesale market issues in 2015

The regulatory focus in 2015 was mainly on:

- Addressing market issues by removing market distortions and imposing measures for the alleviation of structural asymmetries.
- Proceeding with the power market restructuring and, especially, with the design of the implementation of Target Model in Greek wholesale market, and
- Clarifying and harmonizing the provisions of the Transmission Network Code and the Market Operation Code.

Indicatively, during 2015, RAE worked on the following issues:

- 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. The proposed design was set to public consultation which was concluded by the end of 2014. In 2015, RAE continued to work on the proposed High Level Market Design and to keep track of the developments on a European level in order to formulate a more detailed document. It is expected that in 2016, RAE will provide and decide on a document presenting the regulatory guidelines, according to which all necessary actions will be instigated immediately for the technical implementation of the Target Model.

Nominated Electricity Market Operator (NEMO)

According to 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 the day ahead electricity market and the intraday market, which is the Market Operator (LAGIE). 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 was designated as the Nominated Electricity Market Operator for a period of four years.

- Alongside the main work of the reorganization of the wholesale market, RAE proceeded with the development of specific regulatory measures, with a predetermined time horizon, to potentially create competitive conditions (contestable market), and to develop those long term requirements that will allow the effective participation of more players in the domestic market, will offer alternatives to the final consumers, and will promote the effective participation of the domestic market in the single market (at regional and European level). RAE worked on the formulation of the NOME type auctions, putting the basic design under public consultation in May 2014, and a more detailed design in August 2014. The proposal consists of the establishment and operation of a forward market that would ensure the access of the independent suppliers (i.e. excluding the incumbent PPC) to lignite and hydro resources held exclusively by PPC.

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.

With regards to the Cost Recovery Mechanism, the full elimination of the mechanism itself was already announced in the context of RAE 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 aforementioned 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 particular 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 in order to limit the cost of the mechanism and avert abusive strategies, while ensuring, simultaneously, that predatory effects are minimised, and given the limited scale of reserves compensation in the current cooptimisation 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 transitory nature and of a limited time frame until the re-organisation of the greek electricity market takes place.

 With RAE Decision 474/2014 the Transitional Capacity Assurance Mechanism (CAM) was extended until 31.12.2014, in order 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 taking into account 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 in identifying the different capacity availability characteristics that are defined as system requirements. Integrating the comments from the first consultation as well as 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 the purpose of a smooth integration in the market, the Transitional FRM will not exceed 12 months.

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, taking into account 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, taking into account 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.
- Statements of availability of hydroelectric power plants.
- Increase limit secondary backup offers.
- Pricing Methodology hydro.
- Compensation tertiary reserve
- Re-evaluation of the framework of charges for electricity exports to charges of the Uplift Accounts.

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 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) in order 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 cash liquidity 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 in particular. 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.

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) in order to take into account additional commands that result in decreased production. The final decision on the detailed compensation methodology is expected to be taken in 2016 because of the need to investigate further the alternatives expressed in the public consultation.

3.2.2 Retail market

3.2.2.1 Monitoring the level of prices, the level of transparency, the level and effectiveness of market opening and competition

Description of the retail market

The overall electricity consumption in the Interconnected System in 2015 recorded a small decrease of 1.8%, in comparison to 2014. 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 2015. This decreasing trend in the overall electricity demand is depicted at the following Table 18.

Table 18. Electricity consumption at the interconnected system (GWh)

	Year	Large Industrial Customers	Household Customers	Small Industrial & Commercial Custmers)	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**
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**
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**
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	5.900	**46.118**

In 2015, stability in the retail electricity market remained and no extraordinary events occurred, with only two company entering the market (TITAN & NOVA Energy) – which already had licenses. Overall, in 2015 there were no major events or developments that affected the representation of retail electricity consumers.

At the end of 2015, ten (10) 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.)

Competition and market shares

PPC SA remained by far the dominant supplier on the interconnected system, as it held almost the entire retail market (99.16% of the total number of customers and about 95.11% 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 2015, a number slightly better than that of the year before, according to the data provided by the DSO. Overall, in the domestic electricity market for the interconnected system, the total number of customers in 2015 was 6,594,123 and their total consumption was 38,162,297 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 2015, 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 as a result 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 a reluctancy 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 19. Suppliers' Retail Market shares by customers' category (type).

By eligible volume (MWh)											
	Total	**PPC**	**ELPEDISON**	**WATT & VOLT AE**	**HERON SA**	**PROTERGIA**	**GREEK ENVIRONMENTAL & ENERGY NETWORK AE**	**NRG TRADING AE**	**VOLTERRA AE**	**NOVAERA ENERGY AE**	**TITAN AE**
Household Customers	5.134.933	5.109.958	16.357	4.109	765	2.711	588	185	260	0	0
Small Industrial & Commercial LV Customers	1.139.862	1.110.889	15.359	3.488	4.019	2.207	2.065	1.044	791	0	0
Other LV Customers (e.g public, agricultural)	309.070	309.070	0	0	0	0	0	0	0	0	0
otal LV Customers	**6.583.865**	**6.529.917**	**31.716**	**7.597**	**4.784**	**4.918**	**2.653**	**1.229**	**1.051**		
Commercial and Industrial MV Customers	8.590	7.446	226	20	482	263	33	76	39	4	1
Other MV Customers	1.668	1.668	0	0	0	0	0	0	0	0	0
Total MV Customers	**10.258**	**9.114**	**226**	**20**	**482**	**263**	**33**	**76**	**39**	**4**	**1**
TOTAL CUSTOMERS	**6.594.123**	**6.539.031**	**31.942**	**7.617**	**5.266**	**5.181**	**2.686**	**1.305**	**1.090**	**4**	**1**
Market Share (%)	**100,00%**	**99,16%**	**0,48%**	**0,12%**	**0,08 %**	**0,08%**	**0,04%**	**0,02%**	**0,02%**	**0,00%**	**0,00%**

Table 20. Consumption by consumers' category/type

By eligible meter points (31.12.2015)											
	Total Consumption (MWh)	PPC	HERON	ELPEDISON	PROTERGIA	GREEK ENVIRONMENTAL & ENERGY NETWORK AE	WATT & VOLT AE	NRG TRADING AE	VOLTERRA AE	NOVAERA ENERGY AE	TITAN AE
Household Customers	15.816.570	15.743.031	5.149	46.981	2.144	3.552	14.306	786	621	0	0
Small Industrial & Commercial LV Customers	9.245.252	8.450.683	279.435	253.886	105.455	59.284	43.604	23.515	29.391	0	0
Other LV Customers	3.276.509	3.276.509	0	0	0	0	0	0	0	0	0
Total LV Customers	**28.338.330**	**27.470.223**	**284.584**	**300.866**	**107.598**	**62.836**	**57.910**	**24.300**	**30.012**		
Commercial and Industrial MV Customers	8.351.239	7.352.629	413.121	237.776	240.252	21.932	10.359	40.459	31.362	1.792	1.557
Other MV	1.472.727	1.472.727	0	0	0	0	0	0	0	0	0
Total MV Customers	**9.823.967**	**8.825.357**	**413.121**	**237.776**	**240.252**	**21.932**	**10.359**	**40.459**	**31.362**	**1.792**	**1.557**
TOTAL CUSTOMERS	**38.162.297**	**36.295.579**	**697.705**	**538.643**	**347.851**	**84.768**	**68.269**	**64.759**	**61.374**	**1.792**	**1.557**
Market Share(%)	**100,00%**	**95,11%**	**1,83%**	**1,41%**	**0,91%**	**0,22%**	**0,18%**	**0,17%**	**0,16%**	**0,00%**	**0,00%**

Supplier Switching

Following the events of 2012 in the retail market, customer switching in 2015 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 21 depicts the main figures of supply switching in the interconnected system in 2015:

Table 21. Supply Switching, 2015

	Total Customers		Customers having changed Suppliers					
	By number of eligible meter points (2015)	By eligible volume 2015 (MWh)	By number of eligible meter points	2015 (%)	2014 (%)	Customers' consumption who changed Supplier in 2015 (MWh)	2015 (%)	2014 (%)
Household Customers	5.134.933	15.816.570	16.704	0,33%	0,10%	27.997	0,18%	0,06%
Small Industrial & Commercial LV Customers	1.139.862	9.245.252	11.476	1,01%	0,62%	115.707	1,25%	0,84%
Other LV Customers	309.070	3.276.509	0	0,00%	0,00%	0	0,00%	0,00%
Total LV Customers	**6.583.865**	**28.338.330**	**28.180**	**0,43%**	**0,19%**	**143.703**	**0,51%**	**0,31%**
Commercial and Industrial MV Customers	8.590	8.351.239	652	7,59%	3,23%	247.753	2,97%	1,15%
Other MV Customers	1.668	1.472.727	0	0,00%	0,00%	0	0,00%	0,00%
Total MV Customers	**10.258**	**9.823.967**	**652**	**6,36%**	**2,71%**	**247.753**	**2,52%**	**0,97%**
TOTAL LV & MV CUSTOMERS	**6.594.123**	**38.162.297**	**28.832**	**0,44%**	**0,19%**	**391.456**	**1,03%**	**0,48%**

Price monitoring

This section concentrates on the prices offered by PPC in 2015, given that, for this particular year, PPC's market share in retail was over 97%. In the path to remove remaining cross subsidies in the PPC retail tariffs, amendments were made in July 2014 for the following categories:

- Increase of around 20% in prices for residential consumers with a consumption of 0-800 kWh/4-month period. In effect prices were increased to reach the same level of prices for the remaining residential consumers with a consumption up to 2000 kWh/4-month period.
- Small decreases to the commercial LV tariffs.

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 behaviour 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. According to these principles, tariffs should be simple, transparent, cost-reflective and avoid cross-subsidies; they must take into account 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, in order to take into account the specific characteristics of each particular 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 in order to ensure availability and clarity of information, to the benefit of final consumers, while the retail domestic market evolves and matures further.

Price-comparison tool

In order 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 particular consumption level and consumer category.

3.2.2.2 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), the majority of 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. According to the Commission's above Decision:

All NIIs except Crete are recognized as micro isolated systems according to art. 2 par. 27 of the Directive 2009/72/EC, while Crete is characterized as a small isolated system according to 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 authorisation procedure for new capacity fail to provide for the satisfactory authorisation 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, in order 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 programme 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 the majority of 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.

3.3 Security of supply

3.3.1 Monitoring the balance of supply and demand

Table 22 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 2015 had a slight increase of 1.5%, compared to 2014. 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 taken into account, then the total consumption in 2015 was 51.3 TWh, showing a modest increase of 2.1%, with respect to 2014 (50.23 TWh).

Table 22. Evolution of annual electricity consumption in the interconnected system									
	2007	***2008***	***2009***	***2010***	***2011***	***2012***	***2013***	***2014***	***2015***
Electricity consumption excluding pump storage (GWh)	55.253	55.675	52.436	52.329	51.492	50.289	48.451	45.953	46.641
Peak load MW	10.610	10.393	9.828	9.902	10.055	9.894	9.161	9.263	9.813

Table 22. Energy and peak power demand in the interconnected system, for the 8-year period 2007-2015

On the impact of the economic crisis on the domestic industrial production, it is encouraging that the consumption of high voltage customers continued to have a recovery trend, albeit small one (0.5%), especially in March and April, where the highest increase in percentage monthly basis (4.4% and 4.7%) was observed. The maximum value was recorded in July 2015 and was 611 GWh, compared with 595 GWh and 580 GWh in the previous two years, and 675 GWh in July 2008, ie before the onset of the economic crisis.

Fuel Shares

The increase in consumption in 2015 and the significant decline in imports in the second half of the year, boosted electricity especially from natural gas plants. More specifically, the lignite production showed a further substantial fall in 14,5% (-3290 GWh) by 2015 compared to 2014, down to 19.4 TWh, compared with 22.7 TWh in the previous year. This decline would be potentially even greater if the imports were not limited due to capital controls at the end of June 2015, which resulted in the closing of the output gap from domestic lignite plants and natural gas plants. The production of natural gas increased to 7,3 TWh, compared to 6,3 TWh in 2014, showing a significant increase of 15%. Hydropower production also increased significantly, to 5,4 TWh compared to 3,9 TWh in 2014, largely reflecting the strong hydro recorded in the first quarter. Production from renewables and CHP showed a rise in 9,7TWh, compared with the two previous years remained unchanged at 8.6 TWh, while the oil production in the Interconnected System was zero crossing, over 1 GWh (under conducting ignition test new units) in 2014. Overall, domestic production showed a slight increase of 0.5%, reaching the 41.8 TWh compared to 41,6 TWh.

Figure 12. Monthly production across fuels

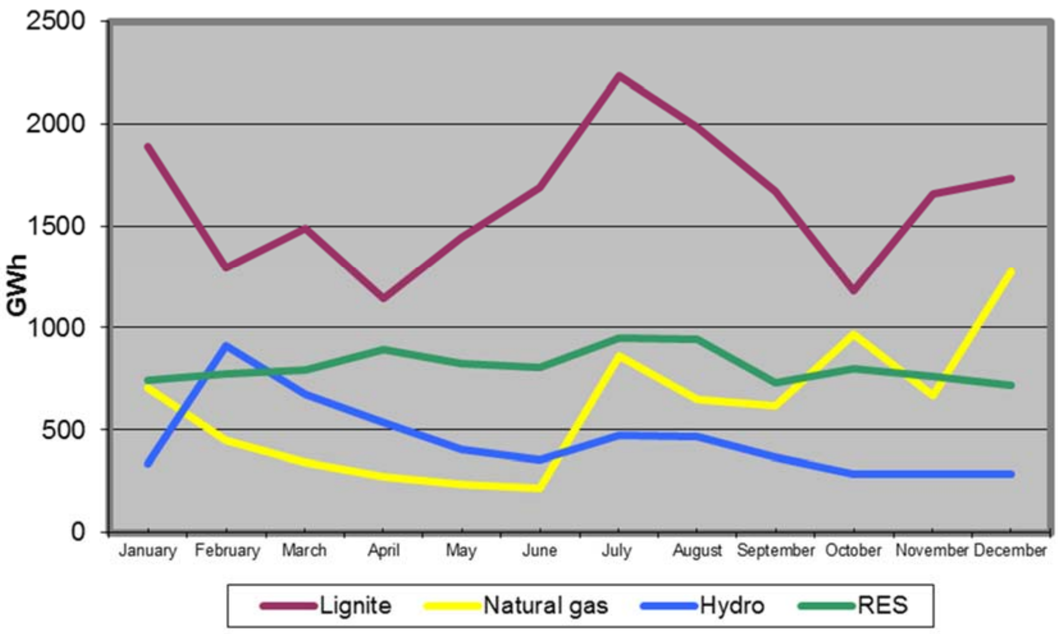


Figure 12 shows the monthly variation of actual production per technology, reflecting seasonal changes in demand, and the influence of stochastic factors and regulatory measures. In general, the lignite production showed fluctuations between 1142 and 2237 GWh monthly. Noteworthy is the sharp decline in lignite production in April and October 2015, which followed the decline in the corresponding period of demand.

The production of natural gas units showed a significant increase during the second half of 2015, and strong volatility, with monthly levels between 214 and 1276 GWh. This production followed a downward trend as in June 2015, where it reached the level of 214GWh, but increased considerably from July to the end of the year, reaching production of 1276GWh in December, due to a reduction in imports, as mentioned above, and a reduction in the price of gas. The latter is linked partly to the pursuit of gas producers to consume their contractual amounts to prevent their exposure to the clause of take-or-pay. It is also noted that the complete abolition of the Variable Cost Recovery Mechanism from 1.7.2014 led to a contraction in production of independent producers mainly in the second half of 2014, continued in 2015, as the integration of the units now accompanied by inadequate cost recovery during the hours that the SMP does not reflect the variable costs of the most expensive unit distributed, but instead significantly below it. Moreover, the abolition of the Transitional Capacity Assurance Mechanism by 1.1.2015 contributed to this phenomenon, and further reduced the income of producers. Consultations on new mechanisms and the adoption of reforms to the end of the year is not reflected in market image effect which is expected to become evident since the beginning of 2016.

Hydropower production showed high levels in general, due to increased input, ranging between 285 GWh in December and 914 GWh in February 2015. The production of renewable energy showed the expected seasonal variations, ranging between 720 GWh in December and 952 GWh in July 2015 and was maintained high between April and August.

An important factor was the rise of interconnections' balance during the first half of 2015, continuing the surge that had occurred in 2014, which reflects the strength of imports due to lower prices prevailing in neighboring countries. Characteristically, the months of January and March 2015, the interfaces balance hovered in the range of 1 TWh. However the capital controls, imposed during the second half of 2015, halted the rise in the balance, with imports showing a significant decline, particularly during July and August (504 GWh to 654 GWh in July and August). In September, imports showed a slight increase but the last quarter of 2015 fell again. It is worth noting that the Greece - Italy interconnection (HV DC Link 400kV) remained inoperative due to damage from the October 10, 2015 until December 22, 2015. Overall, throughout the year, as shown in Figure 13, due to the high rate of imports in the first half of 2015, the balance amounted to 9.6 TWh in 2015 compared to 8.8 TWh in 2014.

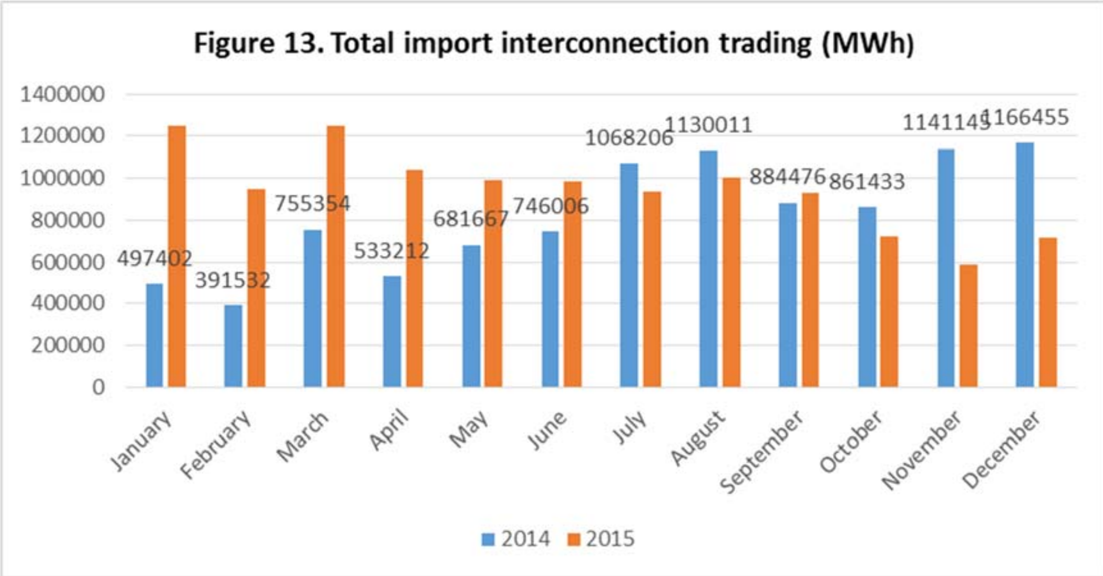
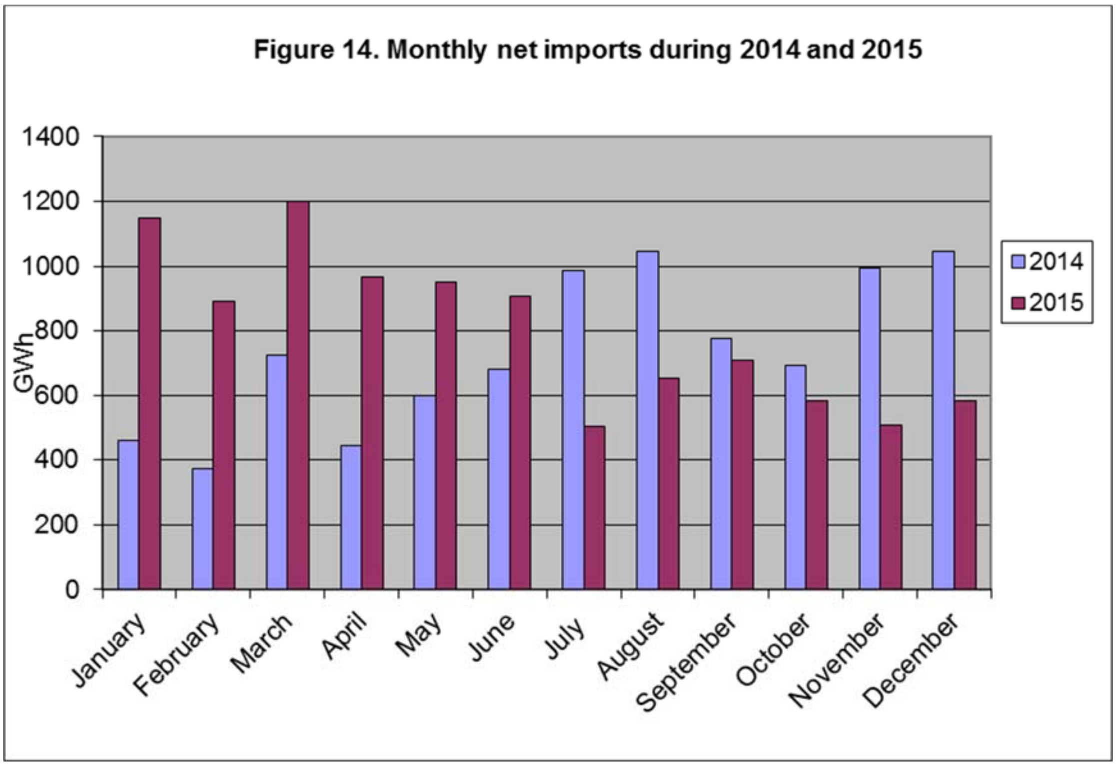
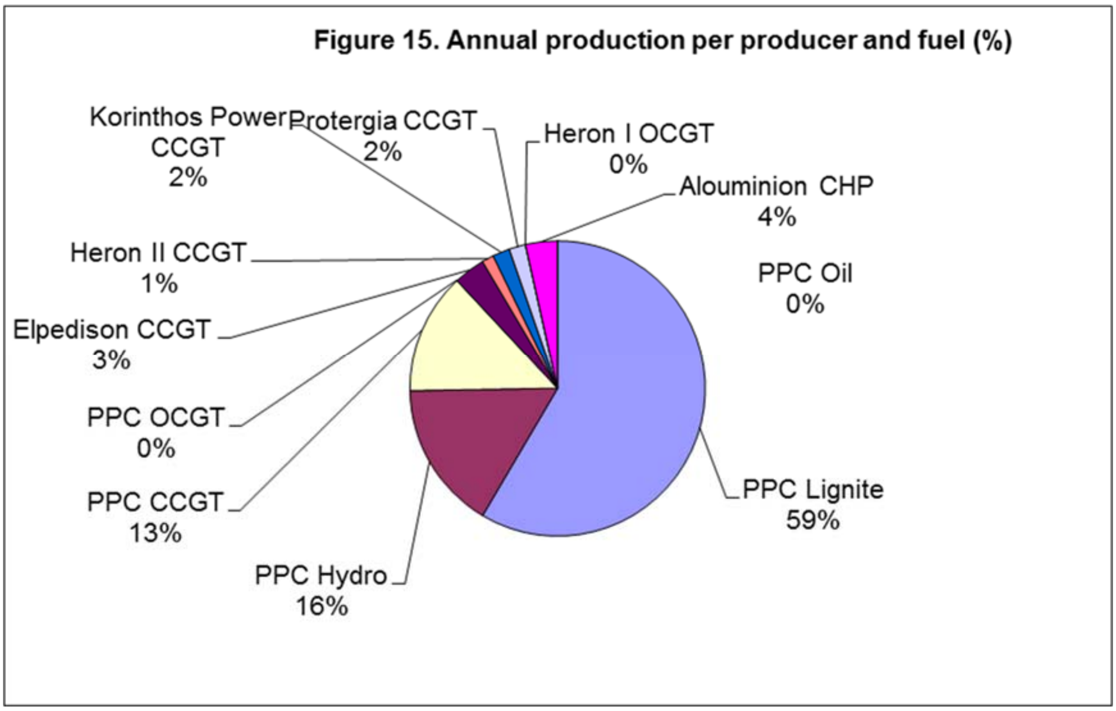


Figure 14 depicts the monthly net imports during 2014 and 2015 and Figure 15 depicts the annual share of fuels and net imports.





Installed capacity

During 2015, the market concentration in the field of conventional production increased and in terms of installed capacity, PPC's share of total conventional technologies (except RES) was 81.756%, against 80.6% in 2014. Note that the concentration of production than conventional technology sector had also strengthened in 2013, with the commissioning of the PPC gas unit Aliveri V (420 MW). The share of PPC to the total installed capacity, including renewables, increased to 61.6% in 2014 from 60.53 the year before. It is also worth noting that, in the interconnected system, the total installed capacity of the gas units now, for the first time, exceeds the installed capacity of lignite plants. This development is the result of strong investment incentives provided, since 2006, through the Capacity Adequacy Mechanism, in order to tackle the serious power deficit loomed at the time, before the onset of the economic crisis, as well as of the State decision not to invest in coal-fired units. The phasing out of obsolete lignite plants is expected, in the medium term, to significantly influence the mix of electricity production.

Figure 16. Net installed capacity per producer and fuel (MW and %)

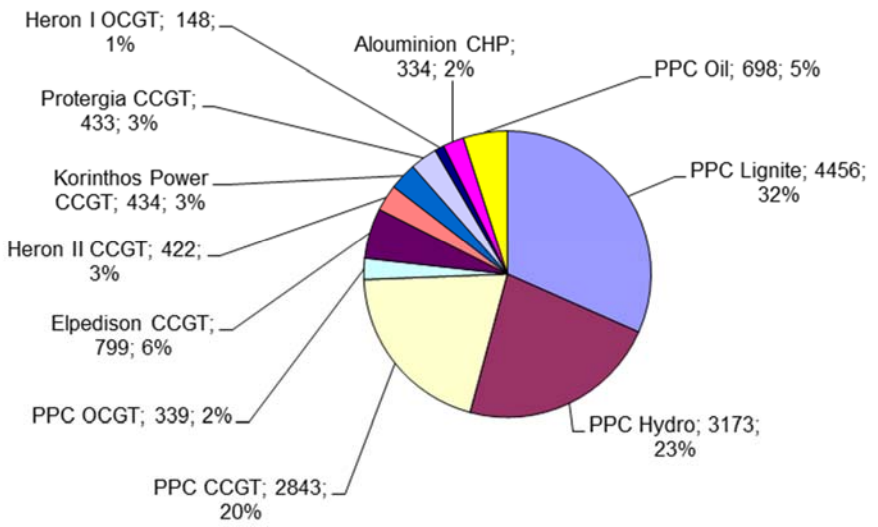


Table 23: Installed capacity by fuel and ownership

	Installed Capacity except RES 2015 (MW)	Installed Capacity except RES 2014 (MW)	Installed Capacity except RES 2013 (MW)	Capacity factor %		Share in installed capacity by Group (%)
PPC Lignite	4456	4456	4456		PPC	81,75%
PPC Hydro	3173	3173	3018		Elpedison	5,68%
PPC CCGT	2843	1998	1998		prot+aloum+kp	8,53%
PPC OCGT	339	339	339		heron	4,05%
Elpedison CCGT	799	799	799			
Heron II CCGT	422	422	422		**2015**	**PPC**
Korinthos Power CCGT	434	434	434		**Share in installed capacity (except RES)**	81,7%
Protergia CCGT	433	433	433		**Share in total installed capacity**	61,6%
Heron I OCGT	148	148	148			
Alouminion CHP	334	334	334			**HHI capacity**
PPC Oil	698	698	698		**2015**	6804

Total Thermal+Large Hydro	14077,9	13232,9	13077,8		**2014**	6624
Renewables	4593,5	4463,6	4295,2		**2013**	6597
Total	18671,4	17696,5	17373,0			
Sources: ADMIE-LAGIE						

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

According to regulatory instructions, and in the context of current legislation, the System Operator, ADMIE S.A., submitted in 2014 to RAE, a Generation Adequacy Report for the period 2015-2024. 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 2014 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 realised (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. 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.

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. In particular, it is noted that to ensure sufficient resources and minimise 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, in order to cover the possibility of loss of the largest power unit in each autonomous system. Moreover, according to Decision 2014/536/EE of the European Commission, exemption has been granted for renovation, upgrading and expansion of thermal units on non-interconnected islands, in order to address security of supply issues, with special focus on the necessity of interconnections.

3.4 Consumer Protection

3.4.1 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 24 illustrates the implementation status in Greece of the measures set out in Annex 1.

Table 24. 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, with the exception of 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 of the required obligations. Suppliers are obliged to introduce a Code of Contact based on at least the above referred principles.
Customers are not charged	e)	Supplier switching is free of charge according to

for changing supplier.		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.

3.4.2 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.

3.4.3 Consumer empowerment

One of the main priorities of the Authority in 2015 was consumer’s protection regarding easy access to significant information on energy developments and the upgrading of the quality of electricity distribution services.

3.4.3.1 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:
   a. The construction of a new electricity supply that requires simple network extension, within working 40 days.
   b. Electricity interruptions for Medium voltage consumers due to network failure or planned interruptions are restored within a maximum of 12 hours.
   c. Meter inspection after a client’s request is concluded within working 20 days.
2. Written consumer complaints about the quality of voltage, are replied within working 30 days.
3. 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 25: Performance of Guaranteed Services: Consolidated figures, 2009-20152F[2]

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%*

[2] The evaluation of the performance of the new program of Guaranteed Services for 2014 will be available within 2015.

New: Inspection of meter, after client's request		20	Working days						8.26%	4,20%
New: Disconnection after client's request		3							3.43%	2,06%
New: Supply restoration, after network failure/scheduled works, for MV customers		12	Hours						3.00%	0,22%
New: Construction of new connection with network extension		40	Working days						0.79%	1,41%
New: 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.

3.5 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 presents the number of customers and total electricity consumption of the Residential Social Tariff.

Table 26. Number of customers and total consumption - Residential Social tariff 2011 – 2015

	Residential Social Tariff 2011 - 2014		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

Source: DEDDIE (DSO)

3.5.1 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 2015 was 234 and 2014 was 303, revealing a gradual decline in absolute numbers since 2012, remaining however at higher levels compared to the previous of 2012 figures. This reduction is mainly attributed to the lower number of consumer complaints submitted to RAE by the Alternative Dispute Settlement body, i.e. the Hellenic Consumer Ombudsman. According to the yearly report of the Hellenic Consumer Ombudsman the minor decline of the number of consumer reports for the energy sector may be attributed to the effectiveness of the regulatory framework established to combat the energy poverty. The vast majority of consumer reports received by RAE were complaints and disputes (85.8%) rather than enquiries/information requests.

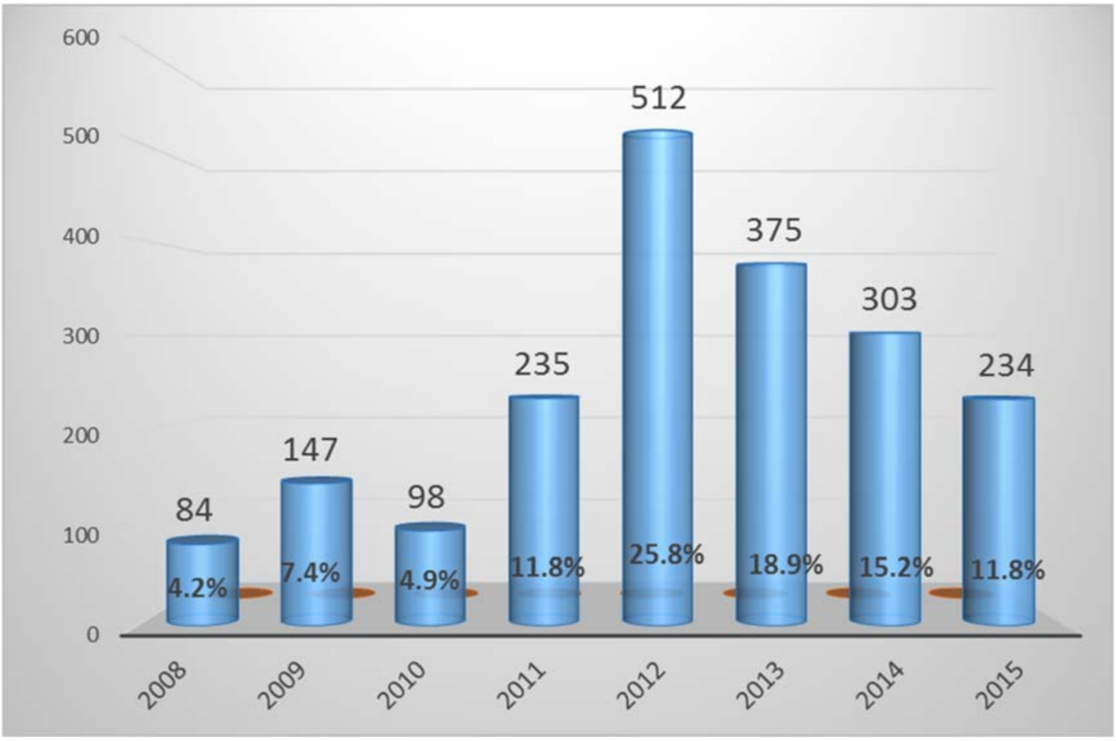


Figure 17. Number of written consumer reports registered to RAE by year

In terms of Supply provider issues, consumer reports of 2015 (Fig 18) 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. a) Invoicing / billing (67,92%), b) transparency/clarity of the bill with respect to listed charges and rates (25.8%), c) Debt settlement issues (17%) related to requests for more adaptable payment settlements of accumulated electricity debt d) disputed mistakes on the calculation of charges (10,7%) e) excessive total cost of bills (6.9%)
2. Prices and rates (7,6%), that is related to the following issues: a) insufficient information on the calculation of charges (6.8%), b) disputed calculation of regulated charges (3,4%)

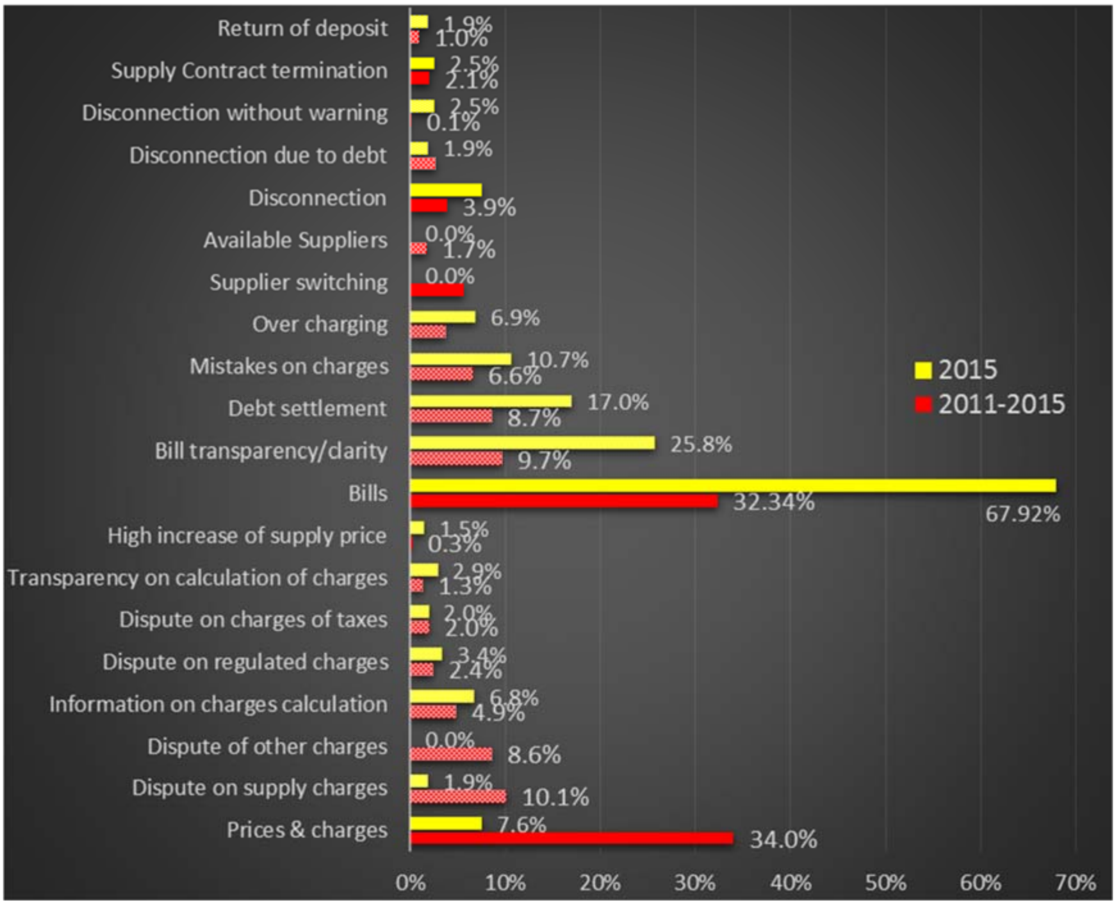


Figure 18. Supply Complaints by thematic category (base:2011-15=1209, 2015=159)

In terms of Distribution Network issues, consumer reports of 2015 amounted to 75 cases are presented in comparison to the corresponding consumer reports of years 2011 to 2015 in Fig.19 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. According to this, the percentage of complaints on disputed/fault meter/consumption readings (41.33%) resulting to high cost bills, has almost doubled compared to the previous years. Another issue that requires further attention and investigation, is the complaints on delays for disconnection requests and/or rejection on connection requests due to outstanding debt (20%). The rest of consumer records are related to complaints with regards to disconnection (9,33%), network installations (8%), and quality of supply for interruptions (8%).

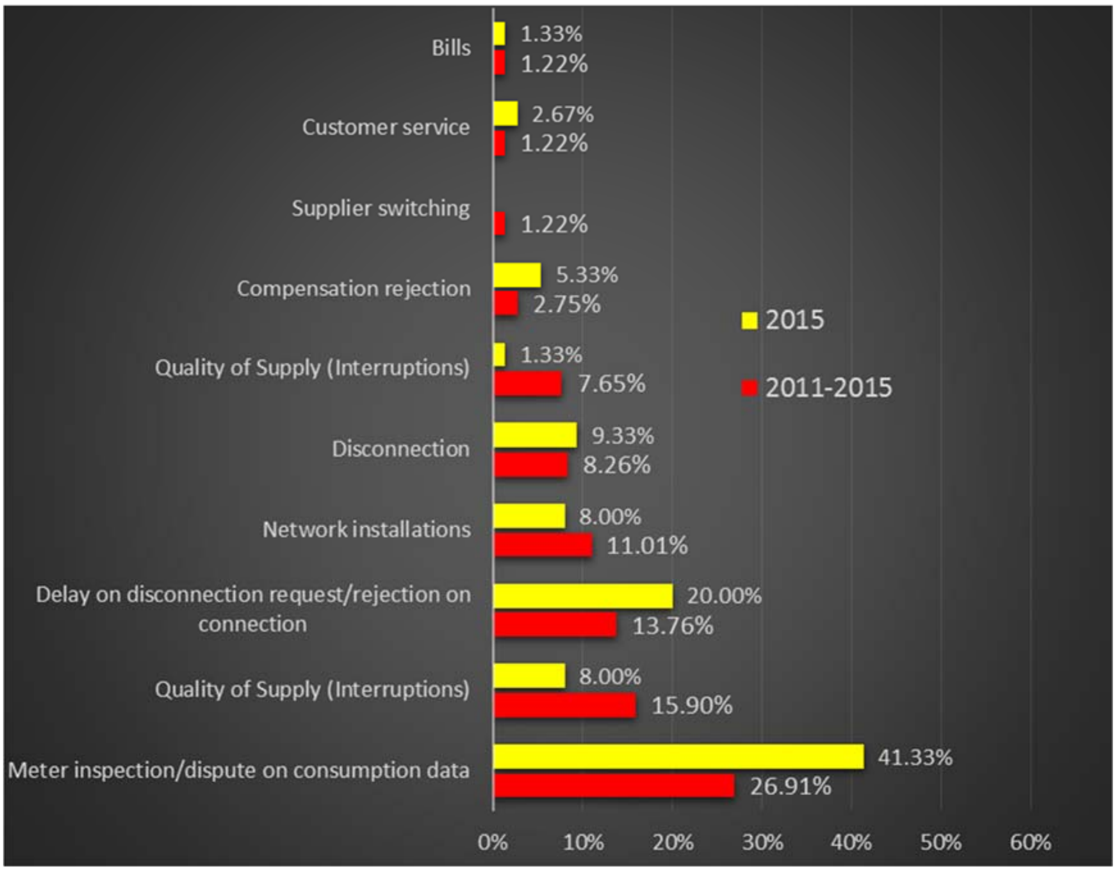


Figure 19. DSO Complaints by thematic category (base:2011-15=327, 2015=75)

Major concerns

In 2015, written complaints mainly concerned energy bills with regards to clarity, comprehensive calculation of charges, incorrect tariff calculations and debt settlement. They were also related to lack or poor information on the justification of supplier's and/or system operator different charges.

It is a fact that the continuous economic crisis makes consumers more concerned on increasing bill expenses. In addition a standard energy bill especially the electricity bill contains many different charges and levies who are associated with difficult and rather scientific terminology that makes the bill quite complicated for the middle educated consumer to understand.

Experience also shows that a large number of customers attempt to resolve their complaints directly with their supplier or system operator, but in many cases it appears that their staff is often not well educated, or do not have sufficient information at their disposal, or are unwilling to offer professional advice. In some other cases lack of trust to service providers leads consumers directly to RAE in order to find proper advice and/or resolution to their problems.

In any case energy service providers should focus on improving the information given to consumers with regards to invoicing and related explanations.

3.5.2 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 does 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 2014 follow:

1. Evaluation of customers' claims for contracts with New Customers

Following a consumer reference, RAE found that a Supplier of electricity did not follow, as described by the Code of Procedure Notice, the finalisation of the supply contract to a customer, under which the Supplier shall ensure that the Consumer has the ability or legal authority to enter into this contract. Therefore, RAE recommended the exact observance of the provisions of the Code of Procurement on the evaluation commission claims process and concluding supply contracts with new customers.

2. Charges of reconnection fee in the event of gas supply disconnection of gas supply company

Following a consumer complaint for the amount of reconnection charges of gas charged by the gas supply company, RAE, in cooperation with the company, and after thorough investigation of costing data, examined the possibility of revising and streamlining these charges. The Authority considered that the reconnection fees should be reasonable and reflect the actual cost of reconnection, a view accepted by this company and requested that the relevant term of the General Terms and Conditions be modified for this purpose. This process was completed in 2015, with favorable results for gas consumers.

3. Consumer Dispute with the calculation of consumed electricity by DSO due to failure of the meter and therefore lack of measurement data

Following a consumer report that disagreed with the estimates consumed electricity by DSO due to failure of the meter, RAE investigated cases and consumer arguments and called the Distribution Network Operator to examine with objectivity claims of customers in order to provide a fair treatment as regards charges. Under the framework of monitoring the proper adoption of the provisions of the Electricity Supply Code, related to Customers protection (Decision of the Deputy Minister of Environment, Energy and Climate Change No. D5-HL / B / F1.20 / oik.6262 / 29.3.201, Gov. V832 / 04.09.2013) RAE evaluated the electricity supply contracts and all other related forms (applications, general terms & conditions, Services Electricity leaflet, site information etc.). Among the main issues addressed, RAE intervened by giving specific guidance to Electricity Suppliers for necessary corrections and/or further inclusion of content.

4. The 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 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, 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 privatise the natural gas incumbent and to allow potential investors to express their interest in acquiring one or both of the above companies. A second amendment of Law 4001/2011, enacted by two consecutive Government Legislative Acts, took place in November of 2012, in order to introduce more specific provisions on the implementation of either the Ownership Unbundling or the ITO model, to accommodate the DEPA/DESFA S.A. privatisation process (tender). Consequently, the TSO’s certification procedure started only at the end of December 2012, when DESFA S.A. submitted an application to RAE to be certified as an Independent Transmission Operator (ITO model).

However, before the completion of the DESFA certification procedure under Article 10 of the Gas Directive, and in particular 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 according to the provisions of articles 9, 10 and 11 of the Gas Directive and Articles 63a, 64 and 65 of Law 4001/2011. More specifically, RAE's assessment revolved around three main questions:

1. Whether the choice of the ITO model for DESFA was legitimate. RAE considered that DESFA did belong to a VIU on 3 September 2009, and thus according to Article 9(8) Gas Directive the choice of the ITO model was legitimate.

2. Whether DESFA complied with the requirements of unbundling rules. RAE concluded that based on the application file DESFA complied with the ITO rules vis-à-vis both DEPA and SOCAR, as it was both autonomous and independent from its VIU.

3. Whether granting the certification would put at risk the security of energy supply of either Greece or the European Union. Based on Article 11(3)(b) of the Gas Directive, RAE took into account in its assessment the following elements: (i) the rights and obligations of the European Union with respect to the Republic of Azerbaijan arising under international law, including any agreement which addressed the issues of security of energy supply; (ii) the rights and obligations of Greece with respect to the Republic of Azerbaijan arising under agreements concluded with it, insofar as they were in compliance with European law; and (iii) other specific facts and circumstances of the case and the third country concerned. More in particular, following also Recital 22 of the Gas Directive, RAE considered: (a) the level of the European

Union's and Greece's dependence on energy supply from third countries; (b) the role of SOCAR in the production, transmission and supply of the Republic of Azerbaijan in the European Union; and (c) the capacity of SOCAR, having the sole control of DESFA, to deny access to the NNGS.

After thorough investigation, RAE concluded that:

(a) the natural gas of the Republic of Azerbaijan, on the one hand, was not likely to put at risk the security of supply of Greece or the European Union as the volumes of Azeri gas delivered to Greece and the European Union were small, especially in comparison to volumes coming in from other third countries, and on the other hand, an increase in Azeri gas supplies would actually improve the security of supply situation in Greece and the wider region given that it would reduce the dependence on gas from other sources and routes; and

(b) RAE was in any case well equipped to impose adequate penalties and regulatory measures on DESFA to prevent, deter or sanction any misapplication of the rules stemming from the 3rd Energy Package, if needed.

RAE promptly notified the above draft certification decision to the European Commission, together with all the relevant information with respect to that decision. Pursuant to Article 3(1) of Regulation (EC) No 715/2009 and Article 10(6) and 11(6) of the Gas Directive, the European Commission assessed the certification file and delivered its opinion to RAE on 28/07/2014. In its opinion, the European Commission:

(a) agreed with RAE about the choice of the ITO model for DESFA;

(b) considered that DESFA complied with the unbundling rules, although it recommended RAE firstly to closely cooperate with DESFA and its owners, following the change of control over DESFA, to develop a plan aimed at reducing the leasing of personnel, and secondly to ensure that DESFA in carrying out services for TAP AG does not discriminate in favor of the latter and to the detriment of other network users;

(c) expressed some concerns about the potential risks for the security of supply of Greece or the EU following certification. In particular with regard to possible security of supply risks stemming from SOCAR's acquisition of sole control over DESFA, the European Commission pointed out the following:

- The risk of governmental acts by the Republic of Azerbaijan or acts by SOCAR and companies affiliated to them that render it impossible or more difficult (such as by creating legal uncertainty or conflicts of law between Azeri and EU legislation) for SOCAR or DESFA to comply with EU energy law, other relevant EU law or Treaty obligations. This includes in particular acts that would impair the development of DESFA's network, such as not providing DESFA with the appropriate financial resources to carry-out necessary investment projects, notably those contained in DESFA's ten-year network development plan, including those concerning the Revithoussa LNG terminal and the future interconnections with the TAP, in accordance with Article 22 Gas Directive
- The risk that the Republic of Azerbaijan could exercise its ownership rights in SOCAR in a manner that could result in SOCAR or DESFA acting contrary to EU energy law, other relevant EU law or Treaty obligations, including the exercise of investigative powers and enforcement action;
- The risk of acts by the Republic of Azerbaijan, SOCAR and/or companies affiliated to them that directly or indirectly sanction the enforcement of EU law against SOCAR or DESFA, including by-measures regarding the supply of natural gas to the EU or the terms and conditions of such supplies. Based on the above remarks, the European Commission took the view that certification should only be granted once it is established that RAE has the power to suspend, on its own initiative or upon request of the European Commission, all voting rights attached to the shares that SOCAR holds in DESFA, should SOCAR and/or the Republic of Azerbaijan take a decision or action that negatively affected the security of supply of Greece and/or the European Union. Implementing the European Commission's suggestion, the Greek government introduced a new article in Law 4001/2011 (art. 65A – Official Gazette A' 194/19.09.2014) to accommodate the needs and alleviate the concerns expressed therein by the European Commission regarding possible security of supply risks stemming from SOCAR's acquisition of sole control over DESFA.

Within two months of receiving the opinion of the European Commission, RAE adopted its final certification decision, having taken the utmost account of that opinion. Decision No. 523/2014 of 25/09/2014 certified DESFA as an ITO and imposed two additional obligations on DESFA: (i) six (6) months after the change of control over DESFA, and after having consulted both RAE and its owners, to develop and submit to RAE for approval a plan aimed at reducing the leasing of personnel in DESFA; and (ii) to submit to RAE for approval every service agreement entered into with TAP AG as counterparty or related to TAP pipeline. It should be noted that the change of control over DESFA has not taken place yet, as the merger clearance, which is another prerequisite for the closing of the deal, is still pending before the Directorate-General for Competition of the European Commission.

During 2015 the transaction 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, in order 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.

B) DSO Unbundling

The three EPAs, EPA Attikis, EPA Thessalonikis and EPA Thessalias 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 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, as regards 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.

4.1.2 Technical functioning

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 for approval an annual balancing plan. The balancing plan includes the TSO estimates regarding balancing gas needs, 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. for the year 2016, which included the estimates of the TSO regarding balancing gas needs (approximately 1.670.000 MWh), as well as an evaluation of possible balancing gas supply sources for 2016. According to this plan, the 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 amount to 3.3% of the total estimated gas consumption, while the year-end data indicated that this figure actually amounted to 3%. For the year 2016, TSO estimates that the balancing gas needs will amount 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, according to 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 according to 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 according to 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 according to 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.

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) tarification 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 2015 are presented in the table below.

Table 27. Coefficients of TPA tariffs for one-year duration contracts in 2015

Tariff	Capacity Charge (€/peak day MWh/year)	Commodity Charge (€/MWh)
Entry Sidirokastro	132,5494	0.1177
Entry Kipi	121,5054	0.0904
Entry Ag. Triada	25,0586	0.0507
Exit Northeast Zone	65,7975	0.1320
Exit North Zone	254,8178	0.4042
Exit South Zone	359,5081	0.4900
LNG Terminal	57,0274	0.1154

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 distribution (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 has to approve distribution tariff regulations and since then, the TAP tariffs are set to 4€ / MWh.

In 2016, RAE will approve a gas distribution tariff regulation which will provide the methodology for calculating gas distribution tariffs.

4.1.4 Cross-border issues

During the course of the year 2015 the final recommendation of DESFA S.A. on the Ten Year Network Development Plan 2015-2024 (TYNDP 2015-2024) 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 2015-2024 (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 2015-2024 has been checked against both the regional and the European TYNDP.

Table 28. 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.
6	ENIMEX S.A.
7	TERNA S.A.
8	HERON THERMOELECTRIC S.A.
9	GUNVOR INTERNATIONAL B.V.
10	GREEK ENVIRONMENTAL & ENERGY NETWORK S.A.
11	GASELA GmbH
12	HELLAS EDIL S.A.
13	GREENSTEEL – CEDALION COMMODITIES S.A.
14	WATT AND VOLT S.A.
15	NRG TRADING HOUSE A.E.
16	SOURLAS S.A. CONSTRUCTIONS
17	EPA ATTIKI S.A.*
18	EPA THESSALONIKI S.A.*
19	EPA THESSALIA S.A.*
20	MAKIOS S.A.
21	ELINOIL HELLENIC PETROLEUM COMPANY 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 has to be registered in the National Natural Gas System Registry, in order to conclude a (transmission or LNG) contract with the TSO. In 2015, forty-seven (47) 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 29. Companies officially registered as NNGS users during 2015		
	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 STEEL INDUSTRY S.A.	Eligible Customer
23	FULGOR GREEK ELECTRIC CABLES 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	YIOULA GLASSWORKS 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 S.A.	Natural Gas Supplier
35	SONOCO PAPER MILL AND IPD HELLAS S.A.	Eligible Customer
36	EP-AL-ME S.A.	Eligible Customer
37	DAIRY INDUSTRY OF XANTHI SOCIETE ANONYME	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.	Third Party
43	EPA Attikis S.A.	Natural Gas Supplier
44	EPA Thessalonikis S.A.	Natural Gas Supplier
45	EPA Thessalias S.A.	Natural Gas Supplier
46	HELLAGROLIP S.A.	Third Party
47	ELBAL S.A.	Eligible Customer

“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, according to 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).

Last but not least 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 according to 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. In the course of 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, in order 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 Markets

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, on a monthly basis. 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 necessary prerequisite for the organization, at a subsequent stage, of a wholesale gas market. Figure 20 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 2013 through December 2015.

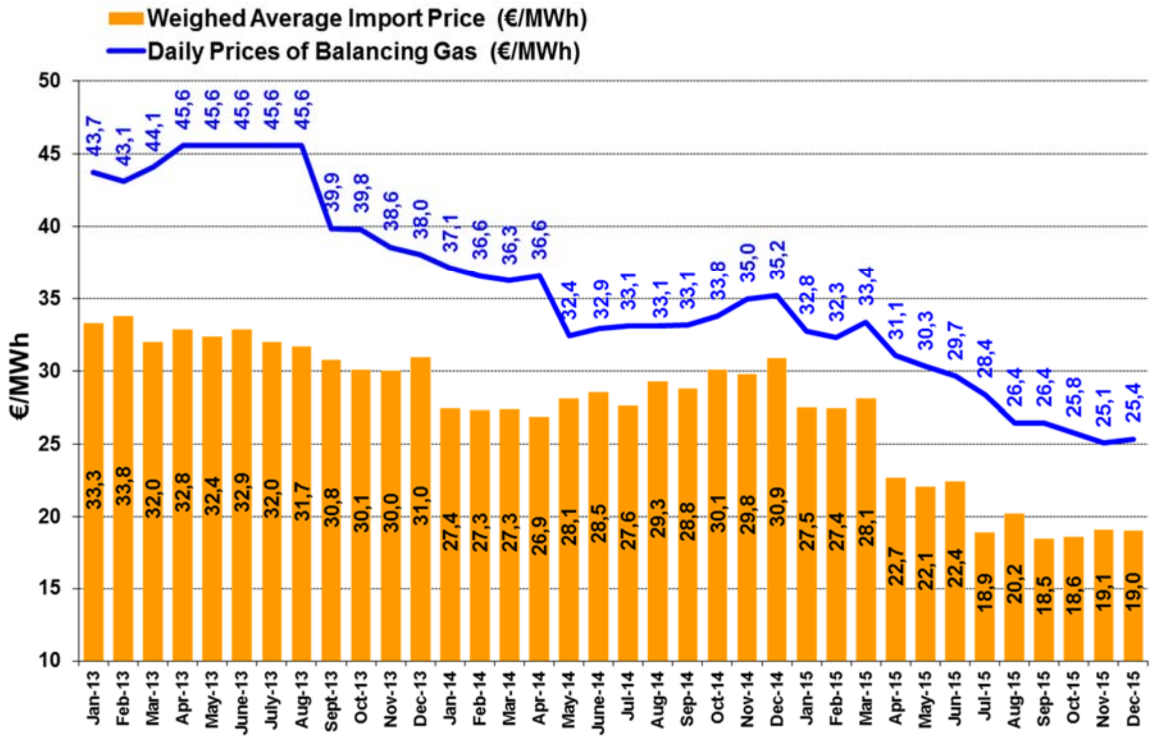


Figure 20. Monthly WAIP vs daily price of Balancing Gas

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 according to the previous regime and which was not taken into account 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 2015. As explained in previous National Reports, there is no indigenous 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 2015, the Revithoussa LNG terminal remains the main channel/opportunity for new entrants in the Greek 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 organised on the basis of bilateral contracts between suppliers and eligible customers; no organised 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 programmes run by DEPA, with the third one gaining ground during 2015.

DEPA runs electronic auctions on a quarterly basis since December 2012 according to the provisions of the Hellenic Competition Commission (HCC) Decision 551/VII/2012 and also 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 programmes in the framework of an extensive consultation run by HCC whereby all major gas market players participated in. As a result, in order to offer Suppliers and Customers the ability to put together a flexible portfolio for the supply of natural gas DEPA has undertaken to make natural gas available on an annual basis in the electronic auctions. Additionally, to further reduce dependence of DEPA Customers by DEPA and to equally treat all participants in the auctions DEPA undertook, as of 01.01.2015, 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).

Table 30. Natural Gas Registry				
	Opinion/Decision RAE	**Ministry ref. number**	**Company**	**Licence**
1	OPINION 356/2010 TP.ΑΠΟΦ.129/2015	Δ1/Α/26859/18.01.2011 A.T. Δ1/Α/15827/07.07.2011	DEPA S.A.	Licence
2	OPINION 357/2010	Δ1/Α/26860/18.01.2011 A.T. Δ1/Α/15830/07.07.2011	PROMETHEUS GAS S.A.	Licence
3	OPINION 375/2010	Δ1/Α/487/07.02.2011 A.T.Δ1/Α/15828/07.07.2011	M&M GAS CO. S.A.	Licence
4	OPINION 3/2011 TP. ΑΠΟΦ. 1344/2011	Δ1/Α/4087/22.02.2011 A.T. Δ1/Α/15829/07.07.2011 TP. PAE 1344/2011	HELLAS POWER S.A. (ex AEGEAN POWER S.A.)	Licence
5	OPINION 27/2011	Δ1/Α/οικ.18723/09.08.2011	EDISON HELLAS S.A.	Licence
6	OPINION 29/2011	Δ1/Α/19466/19.08.2011	GASTRADE S.A.	Licence of Independent NG System
7	OPINION 28/2011 ΜΕΤ.ΑΠΟΦ.130/2015	Δ1/Α/19465/19.08.2011	ENIMEX S.A.	Licence
8	DECISION 217/2012	-	TERNA S.A.	Licence
9	DECISION 870/2012	-	HERON THERMOELECTRIC S.A.	Licence

10	DECISION 573/2013	-	GUNVOR INTERNATIONAL B.V.	Licence
11	DECISION 233/2014	-	GREEN S.A. ENVIRONMENTAL & ENERGY NETWORK S.A.	Licence
12	DECISION 431/2014 ΤΡ.ΑΠΟΦ.393/2015	-	TAP A.G.	Independent Licence of NG System
13	DECISION 502/2014	-	GASELA GmbH	Licence
14	DECISION 559/2014	-	HELLAS EDIL S.A.	Licence
15	DECISION 655/2014	-	GREENSTEEL-CEDALION COMMODITIES S.A.	Licence
16	DECISION 96/2015 ΤΡ.ΑΠΟΦ.281/2015	-	WATT AND VOLT S.A.	Licence
17	DECISION 356/2015		NRG TRADING HOUSE S.A.	Licence
18	DECISION 374/2015	-.	SOURLAS SA CONSTRUCTIONS	Licence
19	N/A	Article 8. L.4336/2015	EPA ATTICA S.A.	Licence
20	N/A	Article 8. L.4336/2015	EPA THESSALONIKI S.A.	Licence
21	N/A	Article 8. L.4336/2015	EPA THESSALIA S.A.	Licence
22	DECISION 437/2015	-	MAKIOS S.A.	Licence

23	DECISION 473/2015	-	ELINOIL HELLENIC PETROLEUM COMPANY S.A.	Licence
* RAE by virtue of Law 4001/2011 (FEK A' 179/22.08.2011), was vested with decisive powers instead of advisoral. ** TP: amendment A.T.: RAE proceeds on the amendment on its own initiative.				

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 Thessalia. 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.

In October 2011, the 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 similar to those of EPA Thessaloniki and EPA Thessalia. 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 2015 were lower than the corresponding prices in 2014. The most important drivers of gas cost plus tariffs are international fuel prices (FO, GO, Crude) and inflation. Some indicative annual average prices for EPA Attica and EPA Thessaloniki, are presented in the table below:

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

Table 31. Indicative, annually-averaged, household tariffs, 2011- 2015			
	EPA Attica	**EPA Thessaloniki**	**EPA Thessalia**
2011	57,54	51,95	50,51
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

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 according to 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 sightimpaired, 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, provided that 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, in order 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, in order 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 (34) were filed to RAE in 2015 regarding the distribution and supply of natural gas in the EPA areas, amounting to 14.6% of all consumer reports submitted to RAE in the same year. The most frequent complaints concerned the bills, connection problems in particular 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 as regards security of supply (SoS) were focused on the update of the reports and plans which are foreseen for a regular update according to 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 2015 amounted to 3.12 bcm, out of which approximately fifty eight percent (58%) came from the power generation sector, as shown in Table 31

Table 32. Natural gas demand by sector in 2015

	bcm @ 15°C	Mtoe (HHV)
Power Generation	1.80	1.64
Industry & HP customers	0.64	0.59
GDCs (Primarily Commercial & Domestic)	0.68	0.62
Total	**3.12**	**2.84**

As depicted in Figure 21, total gas demand in 2015 remained at approximately the same level as gas demand in 2014, which had decreased dramatically compared to the demand level of 2013 (twenty-five percent (25%) decrease), primarily due to the new rules in the electricity Day Ahead Market and the continuing economic recession.

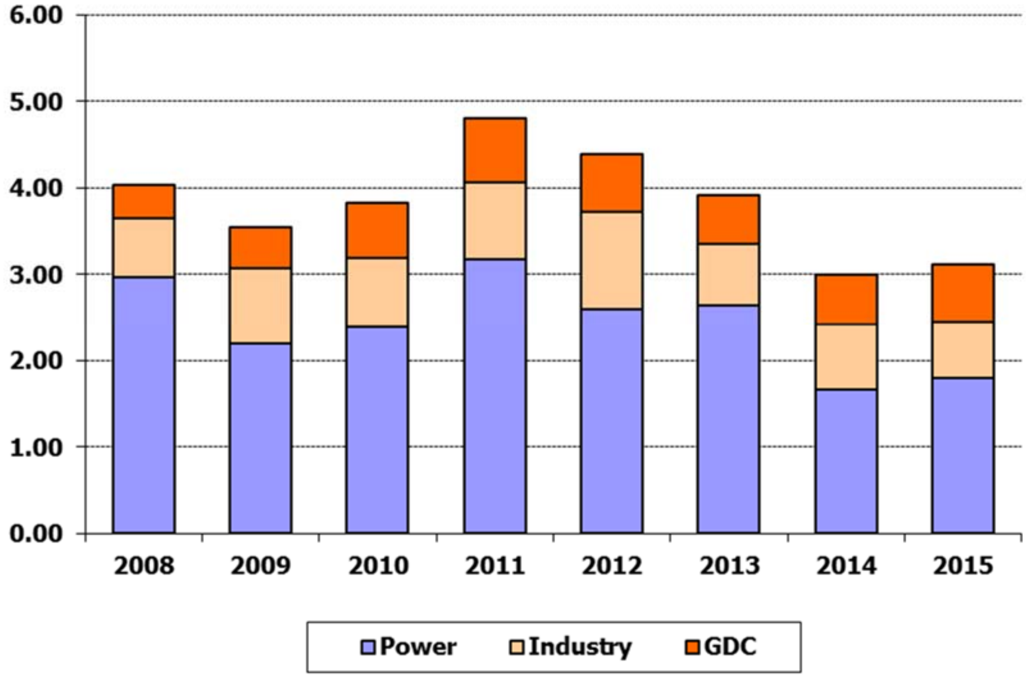


Figure 21. Gas demand per sector (bcm @ 15°C), 2008-2015

There is no indigenous gas production in Greece. In 2015, natural gas was imported in the National Natural Gas System through three (3) entry points. As shown in Figure 22, approximately sixty-two percent (62%) of the gas imported into the country came from Russia and nineteen percent (19%) was imported from Turkey. The remaining nineteen percent (19%) was imported as LNG at the island of Revithoussa and was injected into the transmission system from the Agia Triada entry point.

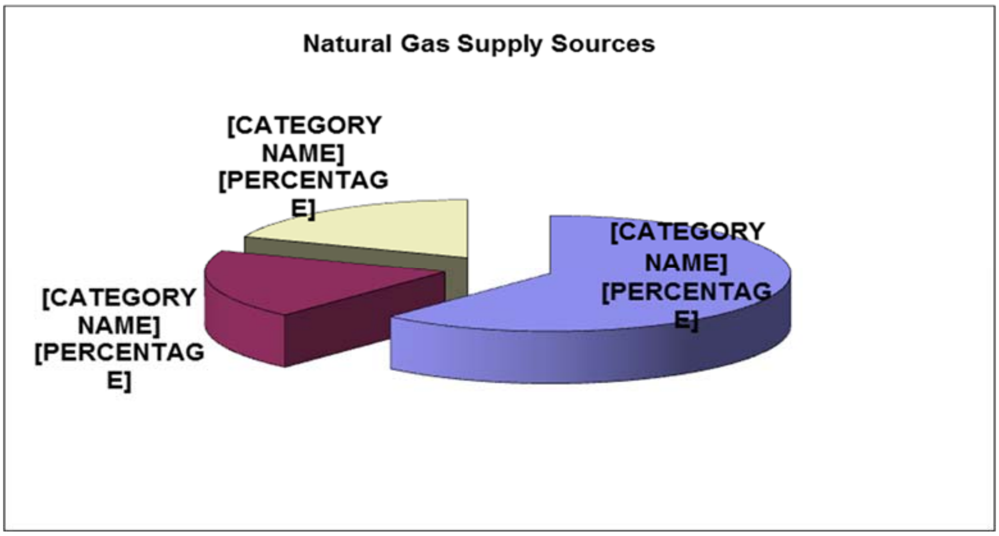


Figure 22. Share of natural gas supply sources in 2015

Figure 23 provides the share of imports from each source during the past nine (9) years (2007-2015). The supply of gas through the existing long-term contract with Russia appears to stabilize at around sixty percent (60%).

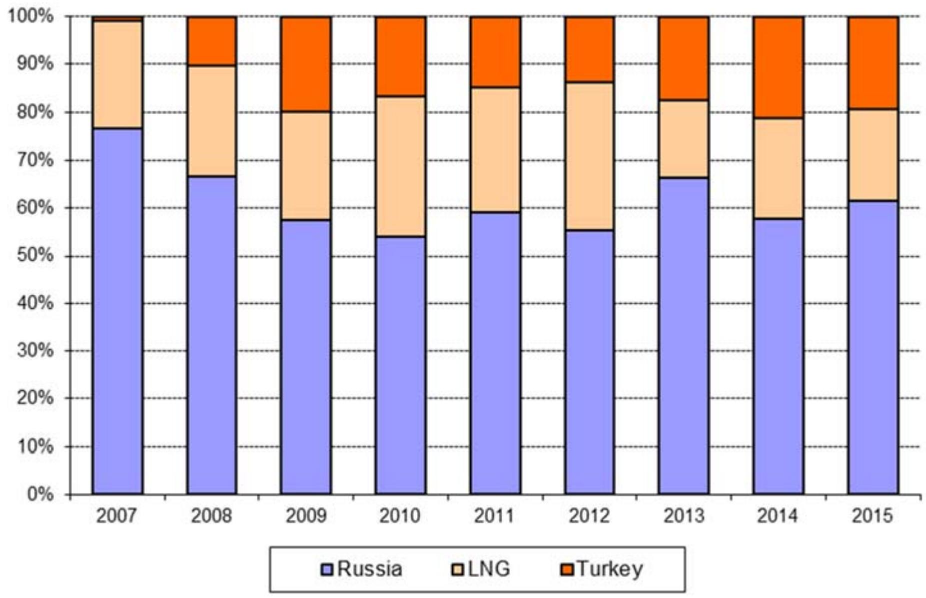


Figure 23. Share of natural gas import sources, from 2007 to 2015

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 in particular the energy available for imports and hydro production.

Table 33. Future natural gas demand (DESFA's estimates)

	2016		2017		2018	
	bcm	**Mtoe**	**Bcm**	**Mtoe**	**Bcm**	**Mtoe**
Power Generation	2.26	2.05	2.31	2.01	2.40	2.18
Industry	1.01	0.92	1.01	0.92	1.03	0.93
Commercial & Domestic	0.47	0.43	0.49	0.45	0.52	0.47
Total	**3.74**	**3.40**	**3.81**	**3.47**	**3.94**	**3.59**

4.4.2 Expected Future Demand and Available Supplies

During 2015, 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 34 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 into a new long term supply contract.

Table 34. Expected natural gas supply-demand balance, 2016-2018

	2016		2017		2018	
	bcm	Mtoe	bcm	Mtoe	bcm	Mtoe
Demand	3.74	3.40	3.82	3.47	3.94	3.59
Supply Contracts	4.13	3.77	3.38	3.08	3.38	3.08
Supply Gap	0	0	0.44	0.40	0.56	0.51

Figure 24 below shows the expected demand - supply balance up to 2025. The demand curve corresponds to the TSO's demand forecast.

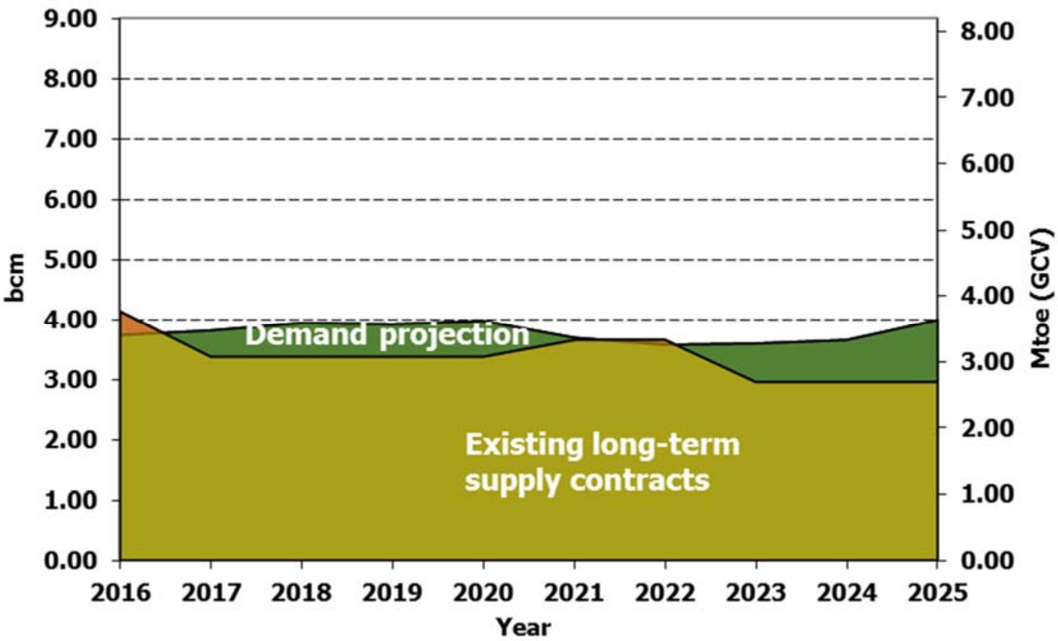


Figure 24. Expected natural gas supply-demand balance (forecast to 2025)

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 35 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 35. Natural gas entry-point capacities

Entry points	Bcm (15°C)
Sidirokastro	4.16
Kipoi	1.66
AG. Triada (LNG Terminal of Revithoussa)	4.80
Total	**10.62**

Table 36. below 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 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

Table 36. Natural gas TSO investment plans

4.4.3 Security of Supply crises

During the period 01-04.09.2015, the Operator declared Emergency Level (Alert Status 3) in the NNGS, 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, on 01.09.2015, there was a natural gas leak detected on the 28th km on the high pressure pipeline section of Megara - Agioi Theodoroi. The Operator interrupted natural gas transmission in the above mentioned pipeline section, so as to ensure the safe, reliable and efficient operation of the National Natural Gas System, a decompression of the pipeline section and a disclosure and inspection on the incident, where an impairment of the metal was discovered on the outer surface of the pipeline.

On 04.09.2015 the Operator restored NNGS in smooth operation since the restoration works of the above mentioned damage and the process of filling the high pressure pipeline section of Megara - Agioi Theodoroi were successfully completed.

4.4.4 Measures to Cover Peak Demand or Shortfall of Suppliers

As mentioned before, during 2015, RAE focused on the update of the reports and plans according to 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 to a large extent 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).

4.4.4.1 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 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 in order 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, according to 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 the course of the year 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.

4.4.4.2 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.