National Report 2018

Regulation and performance
of the electricity market and the natural gas market in Greece, in 2017.

Regulatory Authority for Energy (RAE)

Athens, December 2018.

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1. Foreword

Dear Readers,

The year 2017 was undoubtedly a crucial turning point in the country's energy market with structural, rapid and drastic changes occurring therein. In this regard, several regulatory developments towards the full application of the electricity and natural gas European target models for the benefit of consumers have been achieved.

Regarding the Greek electricity generation mix in the interconnected system (mainland), lignite overpassed RES and Hydro after the latter's dominance in 2016 energy mix. In fact, lignite units generated 16,940 GWh, natural gas units generated 15,400 GWh, RES generated 10.600GWh and Hydro generated 3,500 GWh.

Moreover, as the energy system transformation has implications for maintaining energy security in the short to medium term given the ageing of the lignite generation units, it was necessary for Greece to retain in 2017 demand response measures and a capacity market mechanism with a view to ensuring power system adequacy at peak demand and integrating larger shares of intermittent sources of electricity generation. These measures were proved to be necessary during the cold spell in December 2016 and the beginning of 2017.

In general, throughout 2017 RAE remained firmly committed to its objective and mission to design and implement an integrated package of reforms that would allow for healthy competition amongst participants in the energy markets, eliminate distortions and inefficient practices which may create unjustified burdens to consumers, or not to adequately or reasonably remunerate energy infrastructures and services. Furthermore, an intensive effort was made to maintain and, above all, to further develop the necessary energy infrastructure on mainland and insular Greece, to integrate the non-interconnected energy systems, to reduce the energy cost of consumers, and to contribute to the achievement of the environmental objectives and commitments of the country. These reforms would contribute to Greece's participation in a smooth, organized and efficient way in the integrated European energy market, while safeguarding the country's security of energy supply, and ensuring low energy cost that is the key driver of growth.

To this end, RAE, in the framework of the responsibilities assigned to it by the Greek legislation (in particular Energy Law 4001/2011) and EU law (Third Energy Package), in 2017 proceeded with the adoption of a series of key regulatory decisions, opinions, and suggestions to the Greek State, as well as pushing ahead other initiatives and actions. These major decisions and actions of RAE are summarized below and are analyzed in detail in this 2018 National Report.

[signature]

Dr Nikolaos Boulaxis

President of RAE

2. Main developments in the electricity and gas markets

2.1 Electricity

In 2017 RAE has proceeded with a power market restructuring plan which is essentially the implementation of "the Target Model"[1] in the Greek wholesale electricity market, based on the European Regulations, Directives and Guidelines.

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

The Ministry of Environment and Energy, in close cooperation with other competent bodies and RAE, has also drawn in the second half of 2017, a draft law establishing the Energy Exchange, which was ratified by the Greek Parliament with Law 4512/2018 for the establishment of the Energy Exchange (Government Gazette A' 5/17.01.2018) altering Law 4425/2016 and Law 4001/2011.

Electricity TSO's ownership unbundling process from the incumbent supplier, PPC S.A., started in 2016 and was completed in the beginning of 2017. The Government's plan was to privatize part of the TSO shareholding, and terminate PPC's ownership of ADMIE, but to also keep part of the shares under public ownership. The General Assembly of PPC authorized the sale of at least 24%

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

of ADMIE's shareholding to a strategic investor in the summer of 2016. The General Assembly which took place on 11 July 2016 voted in favor of the sale of 24%. The tender was launched by publication on PPC's website directly thereafter. Finally, the new strategic investor, approved by PPC's shareholders, was the State Grid International Development S.A. (China). The transaction was approved by the Government in 2017, and subsequently RAE certified ADMIE under the OU model with certain conditions.

RAE has been taking all steps necessary for the successful Implementation of the EU Regulation 2015/1222 for the Capacity Allocation and Congestion Management (CACM network code) as well as of the Regulation 2016/1719 for the Forward Capacity Allocation (FCA network code), essentially by commenting and approving the common methodologies prescribed therein, and making all necessary amendments to the national network codes. Under the CACM regulation implementation process, ACER took the final decision on the formation of (10) capacity calculation regions. Greece participates in two Capacity Calculation Regions: GRIT CCR (Italian-Greek border) and SEE CCR (Greece-Bulgaria-Romania borders). In addition, RAE in cooperation of the Ministry and the electricity TSO have been preparing for the full implementation of the other recently adopted European network codes (e.g. on electricity balancing & on system operation).

In fact, in the framework of the implementation of the European Regulation 2015/1222 and European Regulation 2016/1719, RAE issued several decisions regarding the European common methodologies and common rules for the joint operation of the cross - border network interconnections. These common methodologies and rules are decided jointly by the national regulators of the cross - border interconnectors in coordination with the European Agency for the Cooperation of the Energy Regulators (ACER).

The Transitional Flexible Remuneration Capacity Mechanism (TFRM), which was approved by the European Commission and was introduced into the Greek legal system by Law 4389/2016, ended as scheduled at the end of April 2017. In 2017, RAE issued Decision 346/2017 to amend provisions of the System Operation Code and the Market Clearing Code in relation to the Transitional Flexible Remuneration Capacity Mechanism (TFRM) to implement a methodology for sanctions in the event of non-compliance of eligible units with their obligations.

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

- Increase the administratively-defined bidding price cap for the day ahead market scheduling (DAS) from 150€/MWh to 300€/MWh.
- Evaluate restrictions regarding the capacity generation availability of hydroelectric power plants.
- Increase the administratively-defined bidding price caps for the primary and secondary reserves.
- Introduce a pricing methodology for the hydroelectric generating unit variable cost.

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

Regarding the Auctions of wholesale electricity products by the Public Power Electricity Corporation (PPC S.A.), based on the Law 4336/2015, the agreement between the Greek Authorities and the Institutions focused on the objective of progressively achieving a decrease of the incumbent (PPC) Market Shares below 50% by 2020. In order to achieve measurable results in the direction of progressively reshaping the market shares of the incumbent (the objective), that the so-called NOME Mechanism was agreed to be a mechanism applicable both to the existing "Mandatory Pool" model of the Greek wholesale electricity market, as well as under the "Target Model" model. The basic concept for the product design, as introduced in RAE's latest document, provides the opportunity for the whole spectrum of consumers to be supplied by other suppliers as an alternative to PPC.

In terms of the generation mix in 2017 lignite production increased by 9.97% (1486 GWh), as opposed to the sharp decline of 23.26% (- 4517 GWh) in 2016 compared to 2015. Specifically, it amounted to a total of 16.94 TWh (14.9 TWh the previous year). Similarly, natural gas production continued the upward trend of the last two years and amounted to 15.4 TWh (against 12.5 TWh in 2016 and 7.3 TWh in 2015), rising to 23.06% of the total power production. The hydroelectric production declined by 28.62%, from 4.8 TWh in 2016 to 3.5 TWh in 2017, following the downward course of the previous year. RES production and CHP has continued the upward course of the previous year and was equal to 10,6 TWh, recording an increase of 3,67% compared to 2016. Production by other fuels in the Interconnected System was at zero level for a fourth consecutive year. Overall, domestic production showed an increase of 7.91% reaching 45.8 TWh versus 42.4 TWh in 2016.

The assessment of electricity demand dynamics is a multidimensional issue and requires the assessment of a large number of factors. From the data provided by ADMIE, referring to the measured energy consumption of Marginal System and Network, it is shown that demand increased in 2017 by 1.6% compared to 2016 (in 2016 it had decreased by 0.3% compared to 2015). In the HV sector demand significantly grew in 2017 by 2.96%, continuing the upward trend recorded in the previous two years. Indeed, it is worth mentioning that the change in the demand of HV was increased over the previous year in almost all months of 2017.

It should be noted that distribution network demand, published by ADMIE in its monthly reports, includes demand on the Marginal System-Network and demand estimation covered by generation units of the Network. Network's demand in January and February 2017 showed a sharp increase (14.2% and 8.4% respectively, compared to the corresponding months of the previous year), as opposed to the corresponding period of 2016 in which the Network's demand was particularly low (4.1% and 10.7%, respectively). This is largely due to the fact that during January and February 2017 extreme weather conditions prevailed (very low temperature). Specifically, January, mainly due to the cold spell which occurred during 07/01/2017 and 13/01/2017, was one of the coldest months of the last thirty years. As far as the summer of 2017 is concerned, the demand of the Network in June 2017 showed a decrease of 5.5% compared to 2016, while in the corresponding month of 2016 the demand of the Network had recorded a sharp increase of 14.1% compared to 2015. This was due to the fact that June 2017 was relatively cool with normal temperatures for the season, as rains and storms were recorded in the middle of the month.

In 2017, the retail market was in an extremely critical phase, mainly due to the decrease in liquidity, the continued existence of PPC's bad debts and the generally difficult economic environment. More specifically, there was a high level of business and credit risk and continuing the significant cash-flow problems throughout the market trading chain. RAE, throughout the year, has systematically followed the course of financial transactions and, in particular, the development of long-term debts of the market participants, and held hearings with specific participants in the market where investigations were deemed necessary. Because of the complexity of the subject, as well as its significant impact on cash flow throughout the transaction chain of the electricity market, the actions of RAE are expected to be concluded in the first half of 2018.

The year 2017 is considered a reference point for the operation of the Electricity Distribution Network, as the basic regulatory framework was adopted for the operation of the distribution network, i.e. the Electricity Distribution Network Code (pending since 2001). RAE's decision 237/2017 lays down the basic management rules of the national Electricity Distribution Network and provided for the publication of a number of manuals to determine detailed arrangements on individual topics. Following the adoption of the Electricity Distribution Network Code, within 2017, decisions on specific issues were issued – to solve problems of the electricity distribution operation and the electricity market, in particular the issue of electricity theft.

Regarding infrastructure planning, in 2017 the first phase of Interconnection was completed in Cyclades, which was inaugurated in March 2018. The completion of the first phase of the Cyclades interconnection was a historic moment for the country, not only as the culmination of a long and painful effort, and multi-agency cooperation, but also as the vindication of all those who believed and insisted on the vision of the islands' electrical interconnection.

RAE also approved the Ten Years Network Development program of the Greek TSO, ADMIE S.A. Additionally, RAE Approved the 7 years Electricity Supply adequacy program of the Greek TSO. Furthermore, RAE prepared for its participation in the discussion for the update of the EU list of projects of common (cross border) interest (PCI) which is established every two years (next publication in 2018).

In this regard, it is worth noting that in July 2016 RAE received its first file based on the European Commission's Regulation 346/2013 which requested RAE to examine the investment of a Project of Common Interest (PCI) for the interconnection of Israel - Cyprus - Greece (EuroAsia Interconnector). This investment proposal included the design of an interconnection line between Crete and Attica which had been already considered by RAE, in close cooperation with the Regulatory Authorities of Cyprus and Israel, in accordance with the relevant provisions of the regulatory framework. In January 2017 and in September 2017 the project file was updated (resubmission of the application), so that the investment file could be considered as complete in respect of the relevant PCI segment concerning the interconnection between Greece and Cyprus and start the evaluation of the project. In October 2017, the Regulatory Authorities of Greece and Cyprus (RAE - CERA) jointly issued the Cross-Border Cost Allocation (CBCA) after the signature of a Memorandum of Understanding between ADMIE and EUROASIA INTERCONNECTOR LTD (RAE Decision 847/2017). With this Decision, the approval of the Attica-Crete-Cyprus project of 1000 MW execution was achieved. Especially for the Attica-Crete section, according to the submitted MoU, the implementation would be done with the co-operation of ADMIE S.A. - EUROASIA INTERCONNECTOR LTD, on the basis of an SPV responsible to build the project, which will then be handed over in terms of ownership and operation to the ADMIE, while its repayment will be done through the Greek Network Charges.

2.2 RES

A new support scheme for renewable energy resources (RES) and high efficiency combined heat and power (HECHP) installations was published on 9th August 2016. The national Legal basis was Law 4414/2016 on a new support scheme for RES and HECHP. The support scheme intends to incentivize electricity production from RES to contribute to the achievement of the target set by Directive 2009/28/EU on the promotion of the use of energy from renewable sources at 20% share of energy from RES sources on the EU overall gross energy consumption in 2020. Directive 2009/28/EU, set this target for Greece, based on GDP/capita, energy consumption and other indicators, at 18% share of RES on Greece’s overall consumption in 2020. Based on the latest data Greece’s RES share on total final gross energy consumption was 15,32% in 2016, with electricity from renewable sources (RES-e) representing almost 23.2% of the total electricity generation (Big Hydro Units included). Significant new investment is still required to reach the national RES target (18% by 2020).

Technology	Table 1: Number of RES applications and number of generation licenses							
	2016				2017			
	Number of Applications for generation license		Decisions/ Permissions approved by RAE		Number of Applications for generation license		Decisions/ Permissions approved by RAE	
	No	Power Capacity (MW)	No	Power Capacity (MW)	No	Power Capacity (MW)	No	Power Capacity (MW)
Wind	79	429.6	15	178.6	175	1,845.88	14	222.5
P/V	0	0	3	16.89	23	199.45	23	173.5
Hydro small	33	79.52	5	7.62	16	26.11	18	49.66
Biomass	10	27	1	1.5	6	14.87	9	19
Cogeneration electricity& heat	1	4.54	0	0	1	4	1	4.36
Hybrid	56	294.31	1	0.96	96	389.82	0	0
(Tele)heating	0	0	0	0	0	0	1	9.8
Total	179	834.79	25	205.57	317	2,480.13	66	478.82

The main change in the new RES support financial scheme was the abolition of the Feed in Tariff financial support mechanism for new RES projects, larger than 3MW (Wind Farms) and 500kW (other RES technologies) and the adoption of the new mechanism of sliding Feed in Premium. In addition, the new legislation amended the RES levy (ETMEAR) and the structure of the RES financial support account to ensure that the debt in the RES account is eliminated over a 12-months forward looking horizon; the account would be kept annually in balance onwards. On the numerical values of the RES levy allocation methodology coefficients, RAE proceeded, within 2017, to the issue of the decision 1101/2017 for the calendar year 2018. Based on this decision, the unit fees for the RES levy imposed directly on consumers, decreased again by about 6.5%, while in some consumer categories (e.g. agricultural MV use), the decrease has reached the levels of 11%.

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

As from 1 January 2016, the majority RES units and the small combined heat and power plants (henceforth HECHP power plants < 3MW) that commence (commissioning or commercial) operation in the interconnected system, have participated in the electricity market, and have been included in a support mechanism in the form of *Operating Aid* based on a *Differential Compensation Price* (*Sliding Premium*), for the power they generated and is absorbed by the interconnected system. The *Sliding Premium* is expressed in a monetary value per measurement unit of the generated power that is injected, and which is cleared, billed and its transactions are settled monthly, in accordance with Article 5 of the Law.

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

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

According to paragraph 2 of Article 7 of Law 4414/2016, the framework of competitive procedures, ie the technologies/categories of stations, which shall be subject to the competitive procedures, the characterization of competitive procedures as 'technologically neutral' or non-technological procedures and the power-sharing methodology in RES stations located in EEA countries, are formed with decision of the Ministry of Energy, following the relevant opinion of RAE. In accordance with the Law mentioned above, RAE submitted to the Ministry of Energy on 23.02.2017 Opinion no. 2/2017 "in accordance to the provisions of paragraph 2 of Article 7 of Law 4414/2016, regarding: a) the characterization of competitive procedures as "technologically neutral" or non-technological, b) technologies and/or categories of RES and CHP power plants where they are part of the competitive bidding procedure, and (c) the methodology and the power allocation procedure foreseen for RES power plants participation which are installed in countries within of the European Economic Area under the condition of an active cross-border energy trade with them, and any other relevant issue ".

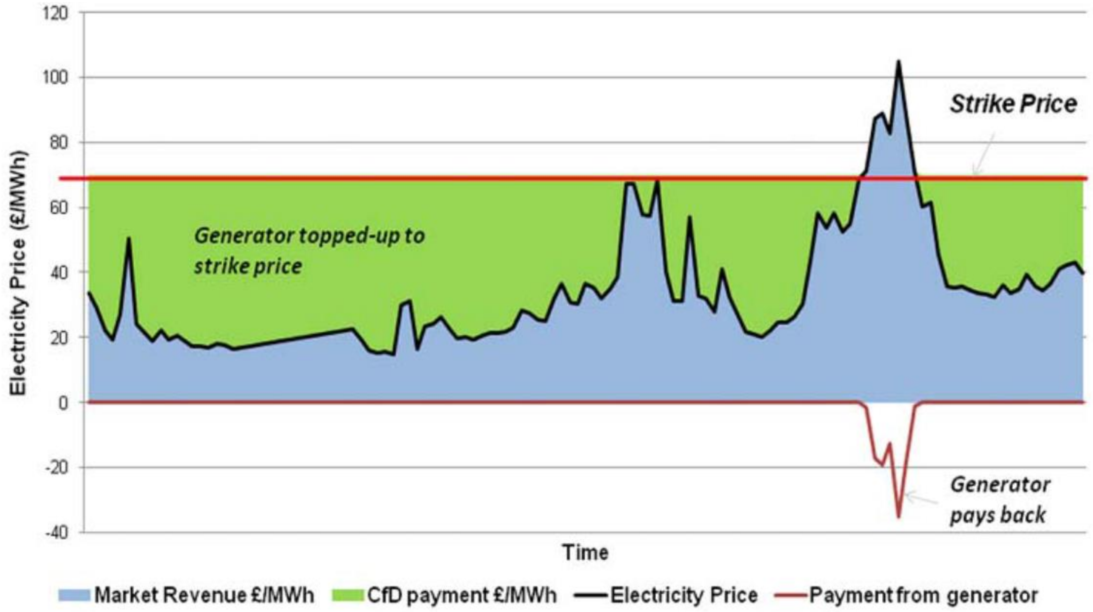

Figure 1: The new Support Scheme in a snapshot

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

Geothermal power > 5MW	108	10%
Other renewable energy technologies	90	10%

2.3 Natural Gas

The current state of the wholesale market

Like in the electricity Market, RAE has proceeded with a natural gas market restructuring plan which is essentially based on ACER's target model.

Currently, the Greek gas market is still based on the execution of bilateral contracts between the suppliers importing natural gas, mainly the incumbent DEPA S.A., and their customers (i.e. industries and retailers); no organized wholesale market exists yet. Transactions that have been recorded so far are the result of the following mechanisms: a) wholesale trade of LNG quantities in-tank, b) resale of gas to eligible customers, and c) the gas release (sale) program by DEPA S.A. per the provisions of the Hellenic Competition Commission (HCC) Decision 551/VII/2012. Moreover, for the first time in 2017, suppliers other than the incumbent were able to import pipeline gas.

According to the Interim Measures proposed by the TSO and approved by RAE in 2015, an amendment of the greek Network Code is underway (public consultation) that will establish a balancing services trading platform, planned to be operational in 2018. The launch of a balancing trading platform is based on the provisions of the European Network Code on Balancing. The operation of the platform will allow all shippers active in the market to trade their imbalance positions (demand-supply) and it is expected to increase the liquidity (transactions) of the Greek natural gas market. Liquidity is further expected to increase with the establishment of a Virtual Transation Point (VTP).

Regarding the implementation of the European Network Codes, the next challenge is the amendment of the Tariff Code in compliance with the TAR Regulation ((EU) 2017/460).

In 2012, DEPA undertook commitments to release part of the natural gas that is importing through its long-term contracts through electronic auctions on an annual and quarterly basis, to offer Suppliers and Customers the ability to put together a flexible portfolio. During 2015 and 2016, HCC ran an extensive consultation to validate the scheme, with the participation of all major gas players. RAE, in its extensive opinion to HCC on ways to optimize the gas release program, . to further reduce dependence of Customers on DEPA and to equally treat all participants through auctions, irrespective of the supply contract that they have already concluded with DEPA (with or without transmission services), proposed that DEPA make all quantities available through the annual and quarterly auctions solely at the Virtual Nomination Point (VNP) of the National Natural Gas System (NNGS). In 2017, DEPA put out in auction 16% of its portfolio.

Transparency in the gas market

RAE, within the framework of its competences regarding monitoring of the Greek energy market, is publishing data on the calculated monthly Weighted-Average Import Price (WAIP) of natural gas in the NNGS, (quarterly review). The publication of data on WAIP, in combination with the publication of data on daily prices of balancing gas (HTAE) on the TSO's (DESFA) website, allows active and potential market participants to gain a better understanding of the price formation in the Greek market, and, therefore, to exploit business opportunities and enhance competition, to the benefit of consumers. Furthermore, the publication of wholesale prices constitutes a necessity at a subsequent stage, of an organized competitive wholesale gas market.

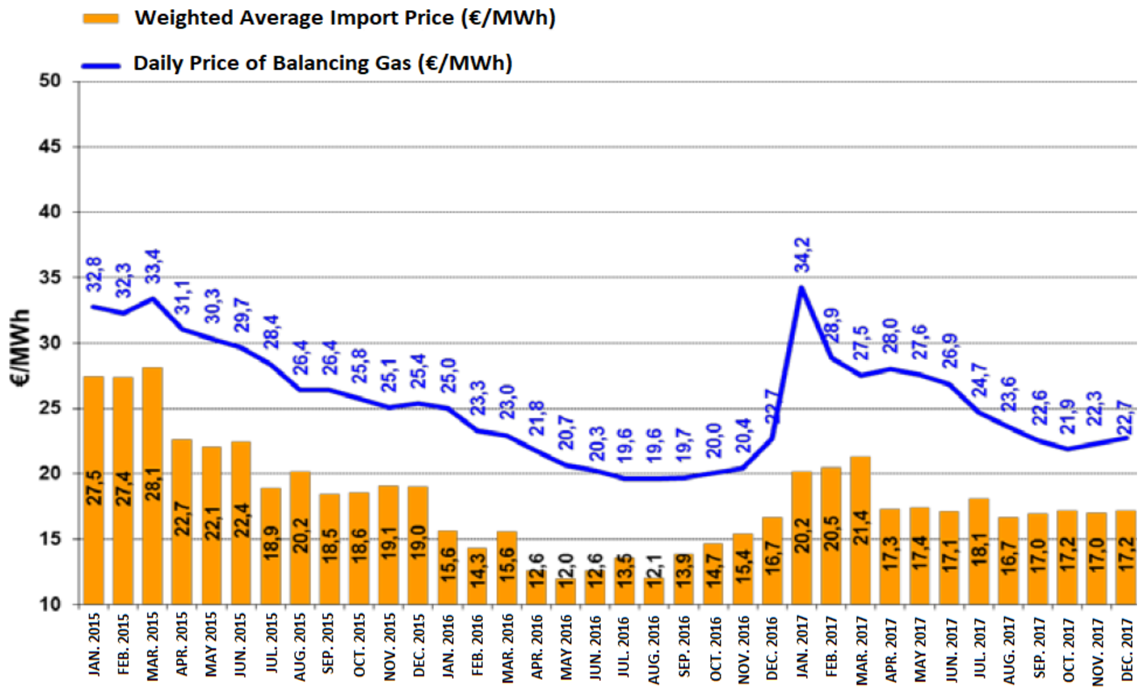

Figure 2: Weighted average import price vs. Daily Price of Balancing Gas as published on RAE's website

Market participants' needs: absolute metric values

The National Natural Gas System (NNGS) transports Natural Gas to consumers connected to the NNGS in the Greek mainland from the Greek-Bulgarian border, the Greek-Turkish border and the Liquefied Natural Gas (LNG) terminal, which is installed at Revithoussa island at Megara (Athens/Attica region). More specifically, there are three entry points into the national gas system:

Entry point	Interconnection's Technical transmission capacity (MWh/day)
1 Sidirokastro (BG)	121.600
2 Agia Triada (LNG)	150.000
3 Kipi (TK)	49.000

During the year 2017, the total natural gas deliveries at NNGTS entry points amounted to 53.9 TWh compared to 44.6 TWh in 2016. Fifty eight percent (58%) of total deliveries came from the interconnection point "Sidirokastron" (Bulgaria), twelve percent (12%) came from the interconnection point "Kipi" (Turkey), and thirty (30%) percent from the LNG terminal station "Agia Triada" (deliveries at Agia Triada include LNG for balancing purposes).

Until recently, there was no considerable competition in imports of natural gas in Greece, as the share of DEPA gas imports corresponded to more than ninety percent (90%) of total annual imports. Specifically, the share of DEPA gas imports in 2015 reached ninety-two percent (92%) of total annual imports and increased up to ninety-five percent (95%) in 2016, with only one (1) other company (big industrial consumer), beyond DEPA, importing natural gas in the country.

The fact that in 2016 DEPA reduced its annual contracted quantity of its long-term contract from Bulgaria by 1 bcm, along with the Interconnection Agreement for the IP "Kulata (BG)-Sidirokastro (GR)" signed between the TSOs of Greece and Bulgaria, in June 2016, allowed in practice new importers to become active in the Greek gas market. In fact, the positive effect of these changes on the wholesale market became clear in 2017, when the share of DEPA gas imports dropped significantly to seventy six percent (76%) and five companies beyond DEPA imported gas with their share adding to the remaining twenty-four percent (24%) of total imports.

Identification and description of market reforms:

Unbundling: based **on** Law 4414/2016, as amended, the natural gas TSO would be privatized and turn from ITO to OU, and the regional natural gas retail corporations (EPAs) would be separated from supply and become pure distribution system operators.

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

Infrastructure development as means for the wholesale market development:

a) Upgrade of the LNG Terminal of Revithoussa (LNG). The Revithoussa LNG terminal remains the main channel/opportunity for new entrants in the Greek gas market. The second upgrade of the Revithoussa LNG terminal is progressing to be commissioned by 2018 and this will offer spare capacity for storage and trade in the Greek market.

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

c) Trans Adriatic Pipeline development (TAP). The construction of the Trans Adriatic pipeline (TAP) started on the Greek territory in 2016. The Trans Adriatic Pipeline will be connected to the National Natural Gas System and therefore opens the Greek market to gas being transmitted through TAP in either direction. In 2017, three working meetings were held between the representatives of, the Energy Regulators of Greece of Italy, and Albania and TAP AG, where the draft of the TAP Network Code was analysed. Further processing will take place with the aim of putting the text on consultation within 2018.

d) New offshore LNG Floating Storage and Regasification Unit (FSRU) near Alexandroupolis The project is part of the list of the European projects of common Interest (PCI) with an estimated capacity of 3-5 bcm/y. The realization of this project will grant the opportunity to Greece, Bulgaria and Romania to have access to new sources of LNG, such as Israel, Egypt, Cyprus and the USA. Gas supply diversification may strengthen the security of supply, increase competition and decrease prices of natural gas and electricity in the region.

Expected state of wholesale market functioning in 2018

Based on the assessment of the current state of wholesale market operation and considering the key drivers towards improved wholesale market functioning, it is expected that the Greek gas wholesale market will not reach to the gas target model in 2018. But, there will be several improvements in market liquidity (increase of transactions).

These improvements will be the result of: a) capacity auctions through RBP regional platform for the Interconnection entry point into the natural gas Greek system in Sidirokastro, b) spare capacity available for trade in the Revithoussa LNG terminal, c) the operation of a balancing platform by the Greek TSO where DESFA will trade gas (buy and sell) with shippers in order to keep the national natural gas system balanced, giving the opportunity to shippers to trade their imbalance positions.

Although the Greek gas market has not developed a spot market, a day-ahead and a forward market yet, the Greek gas market has developed a well-diversified supply structure. Currently, the Greek market has three supply route sources with the prospects to add three additional supply routes (i.e IGB/TAP/LNG terminal in Northern Greece). The increasing number of supply routes shows a high potential for competition to develop in the domestic wholesale market. With the operation of TAP pipeline in the year 2020 the Greek market will also be connected to the Italian market (including reverse flow) thereby allowing active trading of gas and the entrance of new suppliers in the Greek market. By that year with the full implementation of the Network Codes the Greek gas market could be expected to reach the Gas target model.

Security of Supply - Implementation of Regulation 1938/2017

RAE during 2017 focused on the update of the Risk Assessment Study, as well as the monitoring of the implementation of infrastructure which is expected to strengthen the country's security of gas supply, such as the completion of Revithoussa's second upgrade, and in particular the increase of the storage capacity of the LNG station on the island of Revithoussa, with the installation of a new tank with a capacity of 95,000m^3. In accordance with the approved Development Plan, the project is expected to be completed by the end of 2018. Furthermore, RAE is closely monitoring issues by exploiting the potential Underground Natural Gas Warehouse in "South Kavala".

During the year 2017, RAE in collaboration with DESFA, ADMIE, Natural Gas Distribution Network Operators, Suppliers and Users of the National Natural Gas Network and the Ministry of Environment and Energy, proceeded to a second review of the Risk Assessment Study for the supply of the country with natural gas in accordance with the provisions of European Regulation 994/2010 of 20 October 2010. The update of the Study includes among others simulation of scenarios taking account of the most recent gas demand estimates for the periods 2017-2018, 2018-2019 and 2019-2020, but also the expected completion of the second phase of upgrading of LNG Revithoussa Station, as well as a calculation of the impact of the scenarios under consideration on Industrial Consumers, electricity generation and vulnerable customers.

By the end of 2017, Regulation (EU) 2017/1938, concerning measures to safeguard the security of gas supply, entered into force. The new Regulation, which repealed Regulation (EU) No 994/2010, has introduced significant changes regarding the obligations of the Competent Authorities and has enacted provisions for Regional Cooperation. Based on these provisions, RAE, as the Competent Authority, is participating as a member in the Risk Groups of Ukraine and Algeria and more specifically in the elaboration of the Common Risk Assessments of these Groups according to article 7 of the Regulation. Moreover, RAE has been designated as the coordinator for the Trans-Balkan Risk Assessment and in that frame, in November 2017, agreed on a Cooperation Mechanism with the Competent Authorities of the rest Member States in this Risk Group, i.e. Romania and Bulgaria.

Furthermore, RAE participated in the Work Group that has been formed by the Greek Ministry of Energy for the evaluation of exploitation capabilities of the depleted field “South Kavala” and its conversion into an Underground Gas Storage (UGS). By the end of 2017, the Work Group submitted a Study that describes the contribution of the UGS on the Greek gas market. RAE’s opinion is included in the Study, regarding the significant contribution of this infrastructure project in the enhancement of the energy security of supply. A feasibility study was also performed, and a task plan has been proposed. This project is included in the 3rd PCI list.

3. Regulation and Performance of the Electricity Market

3.1 Network Regulation

3.1.1 Unbundling

The EU's third legislative package in 2009 introduced "ownership unbundling" (together with the ITO and ISO models) for transmission system operators (TSOs – owners of high-voltage networks), whereas for distribution system operators (DSOs – owners of low-voltage or "last mile" networks) it maintained the requirements for "legal and functional unbundling".

3.1.1.1 Certified Transmission System Operator - ADMIE S.A.

In 2017 ADMIE S.A.(ADMIE) changed from the ITO model to the OU model as a consequence of its changed ownership structure from 100% Public Power Corporation S.A. (PPS) to 51% ADMIE SYMMETOCHON S.A. (Energiaki Holding), 25% DES ADMIE S.A. and 24% STATE GRID EUROPE LIMITED (SGID).

The new certification procedure under Article 11 of the Electricity Directive (certification of TSOs in relation to 3rd countries) started by the notification from the company to RAE of its imminent change of ownership structure on March 1, 2017.

On June 9, 2017 RAE issued its final certification decision 475/2017 after having taken due account of the Opinion of the European Commission. Certain conditions in the form of a sophisticated monitoring process were nevertheless imposed to ADMIE including the obligation that any future development (ex. regarding the activities of SGID, its mother company and in general China in Greece and Europe, or any change in control over ADMIE etc.) would need to be notified to RAE underpinned also by adequate reasoning for continuous compliance with the unbundling requirements (e.g. security of supply criteria).

RAE's draft certification decision 267/2017 concluded in particular with regard to the Security of Supply criterion that no incentive existed for SGID to exercise control over ADMIE in a manner that would endanger the security of supply of Greece and the EU, as undertakings owned by the Chinese investors were not active in generation or supply activities in Greece or in the EU to the extent or in such a way as to pose risks for the security supply. For RAE, it was also important that the shares of the strategic investor do not increase to the extent that imply that it can appoint the majority of the members of the Board of Directors responsible for deciding on inter alia, the business plan and the budget of ADMIE.

The aforementioned draft certification decision was then immediately forwarded to the European Commission as per the relevant provisions of the Greek and EU legislation, and the latter issued its Opinion on May 24, 2017. The European Commission agreed with RAE that in the absence of commercial activities of energy supply to the EU and/or interests in the energy production in the EU, the incentives and opportunities for exercising influence over ADMIE to the detriment of EU energy security of supply are limited, and thus security of supply concerns are unlikely to arise under the present circumstances.

3.1.1.2 Distribution System Operator - DEDDIE S.A.

The Hellenic Electricity Distribution System 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 System assets (herein the "Distribution System 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 2017.

3.1.1.3 Accounting unbundling

Pursuant to the relevant provisions of the Energy Law 4001/2011 and the European Directive 2009/72, vertical integrated utilities are obliged to keep separate accounts and report unbundled financial statements (Balance Sheet and Profit & Loss Account) for each activity. The Regulatory Authority for Energy (RAE) approves the accounting unbundling rules, based on the company's proposal. RAE published its decision 121/2017 issuing the Principles and Rules for the Allocation of Assets - Liabilities and Expenses – Revenues for the preparation of its unbundled financial statements of "DEDDIE S.A.".

3.1.1.4 Technical functioning

Law 4001/2011 identifies ADMIE S.A. as the owner of the national electricity transmission system. The national electricity transmission system includes: a) High Voltage Lines, b) Cross-Border Interconnection Lines, and c) the total facilities and equipment necessary for the uninterruptible flows of electricity and security of supply into High Voltage lines of 150kV to 400kV, in Greece. In addition, the national electricity transmission grid includes projects of interconnection of the non - interconnected islands to the interconnected (mainland) system (i.e. subsea interconnections HVAC or/and HVDC). The total length of the national transmission system is 11,507km (2017).

According to the Law 4001/2011, the owner of the national electricity distribution system is PPC SA (the incumbent). The distribution system includes: a) the lines of Medium and Low Voltage and few High voltage lines which are part of the distribution system, b) the total facilities and equipment necessary for the uninterruptible flows of electricity and the security of supply into Medium and Low Voltage lines, in Greece and c) the lines of the non - interconnected system of the islands. The total length of the distribution system is 239,231Km (2017).

3.1.1.5 Security and reliability standards, quality of service and supply

Regarding Network Performance and Quality of Service, in December of 2010 RAE published an integrated set of Regulatory Guidelines for the reporting of the Transmission System performance. Following these guidelines, the TSO publishes annual reports on the performance of the Transmission System. 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 (energy not served) [2].

The Distribution Network Code, in force since January 2017 includes provisions for a penalty/reward scheme for QoS regulation.

In this new framework that will become effective in the 2nd regulatory period following Distribution Code approval, to allow for necessary preparatory work to be completed, the role of the Regulator will include the followings:

- 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.

Regarding the issue of electricity theft on the Distribution Network, the new Code sets forth a more refined general framework in an effort to effectively address the growing problem, while ensuring transparency and fairness for consumers. In this direction, operator and network users' rights and obligations are better defined as well as the basic principles and rules which govern, inter alia, the procedures for investigation and detection of theft, communication with network users involved to ensure objectivity and equal treatment, estimation and valuation of non-metered consumption due to theft collection and disposal of energy-theft related income etc. Due to necessary adaptations to operator processes and systems, the new framework for energy theft is expected to become operational within 2018. In the meantime, RAE adopted provisionally rules about combating electricity theft through decisions 236/2017 (Gov. Gazette B' 1881/30.05.2017), and 237/2017 (Gov. Gazette B' 1946/07.06.2017).

Distribution loss factors for 2017 as set out in RAE's Decision no.573/2016, are higher, compared to those applied in the period 2015-2016 (RAE Decision 752/2014), by 0.8% for customers of MV and 2.7% for LV customers, reflecting the change in average energy losses in 2012-2015 (average losses 2014-2015: 8.5% - average losses for 2012-2013: 6.5%). As mentioned above, the total energy losses in the Network have increased significantly compared to the average energy losses of previous years. This increase is attributed to an increase in energy theft (non-technical losses). In 2017, distribution loss factors were updated for 2018, based on 2016 data on actual losses (9,7%), reflecting a 50% growth in distribution losses in 4 years.

[2] 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 2016", CEER Publication.

3.1.2. Network Tariffs for connection and access

Since 2011 (Law 4001/2011, article 140), RAE approves the tariffs for access to the national electricity networks (Transmission System and Distribution Network), one month before their entry into force, based on the proposals submitted to the Regulator by the Electricity Transmission System and Distribution System Operators (ADMIE S.A. and DEDDIE S.A, respectively).

3.1.2.1. Transmission Network operation

Required Revenue and user tariffs:

In June 2014, following extensive public consultation, RAE approved the new methodology for setting the TSO's Allowed and Required Revenue (Decision no 340/2014). The most critical changes, in comparison with the previous applied methodology (a cost-plus methodology) are:

- A multi-year regulatory review period; the Regulator sets the Allowed Revenue for 4 years
- Calculation of TSO's Allowed Revenue based on real terms.
- A detailed methodology for the calculation of Return on Capital Employed based on real pre-tax Weighted Average Cost of Capital (WACC).
- Calculation of assets' depreciation using economic instead of accounting, assets' life.
- Smoothing the volatility of revenues within and between regulatory periods, to minimize the impact of such volatility to consumers' prices.
- 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.

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 (Allowed Revenue and all the adjustments according to 340/2014 Decision) is then allocated to the different consumer categories. The methodology for setting charges (tariffs) on the use of the Transmission System (TUoS) for HV customers/users is set out in the System Operation Code, while the one for customers/users connected to the Distribution Network (MV and LV) is set out in a related Manual approved by RAE.

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

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

For the purposes of the transmission system use charging (TUoS), the following four (4) customer categories are classified: 1. Medium Voltage (MV) customer, 2. Residential customer, 3.

Residential customer with Social Tariff (KOT), 4. Other Low Voltage (LV) and Public Lighting Use LV, excluding Agricultural MV and Agricultural LV that have zero charges.

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

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

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

Based upon the above-mentioned classification, RAE's Decision Ref no 456/2016 approved the following tariffs for 2017 (see table 4):

Table 3: Regulated Tariffs applied for the use of the transmission system in 2017

Consumers Category	**Capacity charge**	**Energy charge (cents €/ kWh)**
Large Consumers HV	24,103 €/MW /per year	-
Consumers MV	1,3329 €/MW Peak time/ month	-
Households LV,	0.13 €/kVA per year	0.527
LV – Vulnerable customers	-	0.586
LV others	0.53 €/kVA per year	0.477

In 2017, which was the last year of the 1st Regulatory Period 2015-2017, and according to RAE's Decision 340/2014, RAE processed the relevant data submitted by ADMIE for the determination of the Allowed Revenue of the next Regulatory Period 2018-2021. The final decision (235/2018) has been taken within the first quarter of 2018.

3.1.2.2. Distribution Network operation:

Required Revenue and user tariffs:

Regarding revenue regulation, the Distribution Network Code (in effect since 2017) includes provisions for a 3-5-year regulatory period. This is subject to a methodology being in place for setting Allowed and Required Revenue. Until this methodology is developed in order for the new framework to become effective, distribution allowed revenue continues to be set on an annual basis, examining operator capex & opex proposals considering historic performance and any changes in current conditions or requirements and applying a predominantly cost-plus approach, with ex-post adjustments for realised capex and opex (beyond a 3% null zone).

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

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

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

Based upon the above-mentioned classification, RAE’s Decision Ref no 455/2016 approved the following tariffs for 2017 (see table 5):

Table 4: Regulated tariffs applied for the use of the distribution system in 2017		
Consumers Category	**Capacity Charge.**	**Energy charge (cents €/kWh)**
Consumers MV	1,179 €/MW Peak Demand /month	0.29
Consumers LV (over 25 kVA), based on the calculation of the maximum supply and taking into consideration the non-used power	3.78 €/kVA subscribed capacity, charged per year	1.67
Consumers LV (over 25 kVA), based on the calculation of the maximum supply and non-taking into consideration the non-used power	3.17 €/VA subscribed capacity, charged per year	1.9
Consumers LV	0.54 €/kVA subscribed capacity, charged per year	2.13
Consumers (vulnerable customers)	-	2.37
Others LV (maximum 25 kVA)	1.47 €/kVA subscribed capacity, charged per year	1.9

In 2017, RAE processed the relevant data submitted by DEDDIE for the determination of the Allowed Revenue of 2018. The final decision (545/2018) has been taken in 2018.

3.1.2.3. Transmission network connection tariffs.

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

3.1.2.4. Distribution network connection tariffs

A detailed methodology for setting connection tariffs has not yet been approved by the Regulator. Basic principles included in the Distribution Network Code provide for a hybrid connection cost model for load (actually coinciding with the model applied historically) and a deep connection cost model for generation.

3.1.2.5. Cross-border issues

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

In 2017 there has been a remarkable decline in import trading schedules (-17.2%), which reached 9,081 GWh, but mainly a significant increase in export trading schedules (29.36%), reaching 2,852 GWh, following the already rising trend observed in 2016. As for imports coming from Turkey, there has been a significant increase of 174.58% following the opposite course of the reduction (by 75%) observed in 2016, while imports from other countries (FYROM, Italy, Bulgaria and Albania) experienced a decrease of 7% to 35% (-19.96% -6.69%, -21.79% and -35.00% respectively). Especially in January 2017, in the middle of the gas crisis in the country, important reductions in imports from the four (4) countries were experienced except for Turkey: FYROM -68.12%, Italy -62.39%, Bulgaria -52.86% and Albania -69.65%.

On the other hand, a spectacular growth of export trading schedules was observed at almost all borders in 2017. FYROM, which now accounts for 32.57% of export schedules, increased by 336.72%; Albania absorbing 30.64% of the schedules, showing an increase of 126.42%; and Italy, which accounted for 26.81% of export trading schedules, recording an increase of 47.61%. It is worth noting that Turkey and Bulgaria recorded a decline in both export schedules (-97.93% and -8.33% respectively) and their share (0,58% from 36,09% in 2016 for Turkey and 9.38% from 13.24% in 2016 for Bulgaria).

During 2017, apart from the gas crisis, two major damage incidents occurred to the interconnection with Italy that had a significant impact on auctioned products and commercial schedules. The first one lasted from 20 October 2016 to 22 January 2017. In that occasion, following a joint decision of Greek and Italian TSOs, no monthly rights auctions were taken place in December 2016 and January-February 2017, while the annual auction of 2017 for this interconnection was carried out with reduced capacity: auctioned 100MW instead of 200MW, which is the usual annual quantity offered.

The second damage lasted from 9 October to 17 December 2017. Similarly, following a joint decision of Greek and Italian TSOs, no monthly auctions were conducted for November and December 2017, as well as for January 2018. On November 25, 2017, the two (2) Operators have informed the participants that the limit of 45 equal days for the curtailments has been achieved and the long-term rights auctioned for the year 2017 were thereafter firm. For this reason, the participants who had purchased through the annual auction for the year 2017 long-term rights, which could not be allocated, would be reimbursed at the price of the initial auction. In addition, the annual auction for 2018 for this interconnection was conducted with a reduced capacity: auctioned 100MW instead of 200MW.

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Table 5: Interconnection power capacity and scheduled trade in 2017						
Description	**Turkey**	**Albania**	**FYROM**	**Bulgaria**	**Italy**	**Total**
Interconnections Voltage (kV)	1 line 400Kv	1 line 400kV, 1 line 150kV	2lines 400kV each	1 line 400kV	1 line 400kV (HVDC)	
Exported Energy (GWh)	16	874	929	268	765	2,852
Imported Energy (GWh)	514	1,208	2,095	3,200	2,063	9,080

Table 7 presents the monthly performance of the import interconnection trading in years 2017, 2016 and 2015 and table 8 presents the cross - border allocation of the interconnection trading in 2017 and its performance compared to the year 2016.

Table 6: Monthly performance of the import interconnection trading 2015, 2016 & 2017 Total import interconnection trading (MWh)			
	2015	**2016**	**2017**
January	497,402	1,248,828	864,626
February	391,532	951,577	1,009,649
March	755,354	1,249,082	1,112,279
April	533,212	1,042,495	984,648
May	681,667	990,553	1,005,412
June	746,006	983,489	925,503
July	1,068,206	939,518	1,125,023
August	1,130,011	1,003,102	1,117,745
September	884,476	928,903	919,373
October	861,433	724,582	729,860
November	1,141.450	586,631	634,984
December	1,166,455	714,818	537,485
Total	**9,856,899**	**11,363,578**	**10,966,587**

Table 7: Cross border allocation of interconnection trading, (2016 - 2017)									
Import share									
Turkey		**Albania**		**FYROM**		**Bulgaria**		**Italy**	
2017	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
5.66%	1.71%	13.31%	16.95%	23.07%	23.87%	35.24%	37.31%	22.72%	20.16%

Table 8: Total export interconnection trading (MWh), 2017 – 2016 -2015			
	2015	**2016**	**2017**
January	98,336	161,563	281,129
February	70,952	44,971	263,471
March	50,191	58,222	120,310
April	72,688	99,082	157,805
May	39,974	92,375	179,804
June	71,275	117,328	176,935
July	438,313	229,501	249,908
August	347,476	206,166	376,668
September	210,450	237,229	253,092
October	131,062	408,292	285,488
November	82,932	210,395	217,167
December	152,629	339,198	289,771
Total	**1,766,278**	**2,204,322**	**2,851,548**

Table 9: Energy Export share per country									
Turkey		**Albania**		**FYROM**		**Bulgaria**		**Italy**	
2017	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
0.58%	36.09%	30.64%	17.51%	32.57%	9.65%	9.38%	13.24%	26.82%	23.51%

Overall, the (net) trading volumes (flows) across borders decreased by 2.56 TWh (-29.09%, decrease), in 2017 compared to the previous year.

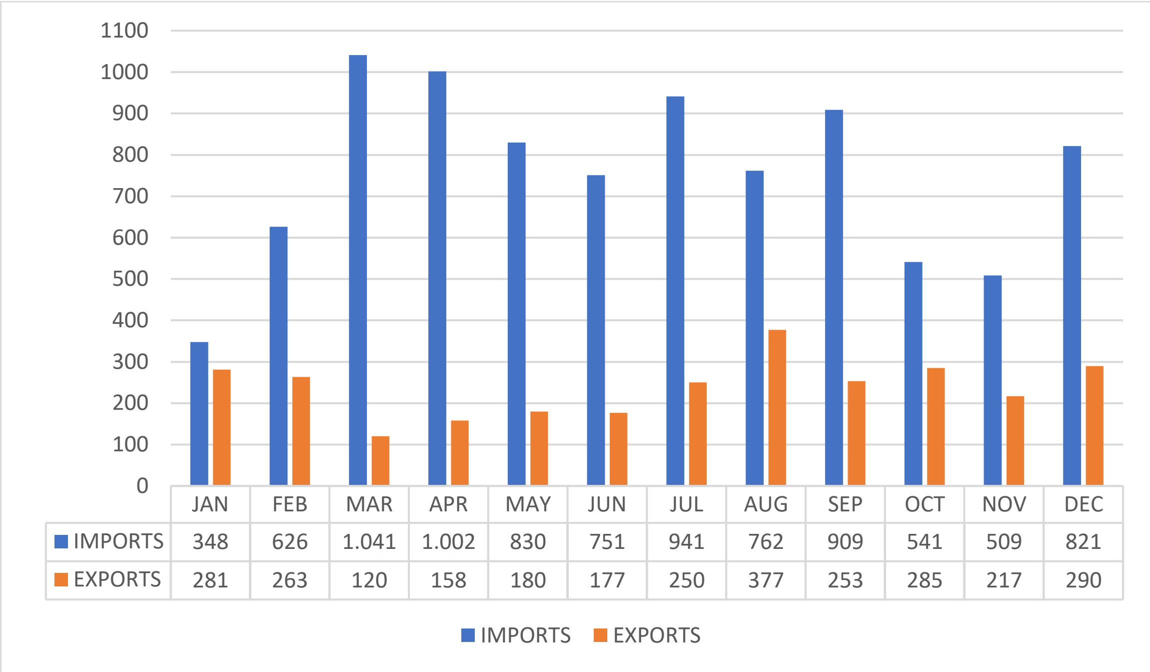


Figure 3: Imports and Exports of Energy in 2017

Regarding the rights auctions at Italy-Greece border, the Joint Allocation Office (JAO) on behalf of Greek and Italian TSOs performs the capacity allocation auctions. During 2017, as for the long-term rights auctions, ACER decided on the all TSOs' proposal for harmonised allocation rules for long-term transmission rights (ACER Decision 03-2017) and RAE approved the all TSOs' proposal for the establishment of a Single Allocation Platform (SAP) in accordance with Commission Regulation (EU) 2016/1719. With the latter decision, the SAP tasks where appointed to JAO, following TSOs reasoning:

a. TSOs have competence for the operation of forward capacity allocation and have thus created a common entity, JAO, to perform this task;

b. JAO is the result of a merger of the former CASC.EU S.A. and CAO Central Allocation Office GmbH, both having a long history in the execution of long-term auctions and thus already executes the long-term auctions on behalf of the majority of TSOs bound by the FCA Regulation;

c. JAO has already adjusted its tools in order to apply the HAR developed by the relevant TSOs and approved by the relevant NRAs as an early implementation of the FCA Regulation;

d. JAO is currently the counterparty to the majority of the market participants applying the HAR and covers the majority of the Bidding Zone borders where forward capacity allocation is applicable.

Furthermore, RAE approved (Decision 1084/2017) the new daily Capacity Allocation Auction Rules for the borders with Italy, with amendments for promoting the further harmonization of auction rules.

With Decision 954/2017, RAE approved the long-term and daily Auction Rules of South East Europe Coordinated Auction Office (SEE CAO) in the borders with Albania, FYROM and Turkey. These rules are implemented in the auctions, which are conducted by SEE CAO, on behalf of SEE Region TSOs. For 2018, new rules for the long-term (annual and monthly) physical transmission rights will apply compared to previous years as IPTO/ADMIE submitted SEE CAO Harmonized Allocation Rules along with their annexes as an early implementation of EU Harmonized Rules and Specific Annex for Bidding Zone Borders, which were proposed by ENTSO-E according to Commission Regulation (EU) 2016/1719. Furthermore, the daily auctions will be conducted only explicitly according to «Rules for explicit Daily Capacity Allocation on Bidding Zone borders services by SEE CAO v1.0».

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

At Greece – Bulgaria border, Common Transmission Capacity Allocation Rights' Rules are being applied at the cross - border Greece – Bulgaria interconnector since 2011 for joint auctions for the allocation of the total transmission capacity, with the Bulgarian TSO performing the monthly auctions, while the Greek TSO performs the yearly and daily ones, along with the secondary market management. The rules for 2018 incorporate the provisions of the 2017 approved auction rules but, also, include the provision of participants reimbursement in the market spread of the 2 markets in case of curtailment, following the best practice of EU HAR and EU Regulations.

Table 10: Greece's cross border interconnections transmission capacity in 2017			
Interconnections	**Transmission lines power (KV)**	**Transmission Power Capacity (MW)**	**Transmission Trading Capacity (real) MW*.**
Greece - Bulgaria	1 line 400 KV	500 - 600MW	500MW
Greece - FYROM	2 lines 400Kv	2X (500-600MW)	0-250MW
Greece - Albania	1 Line 400 KV	500- 800MW	0-100MW
	1 Line 150KV	100MW	0MW
Greece - Italy	1 Line 400KV (HVDC)	500MW	500MW
Greece - Turkey	1 Line 400KV (HVDC)	500-600MW	130MW
Note: Trading available transmission capacity is lower than the nominal transmission capacity due to technical and legal barriers,			
*Transmission trading capacity are defined by the TSOs based on real flows (indicated year 2012)			

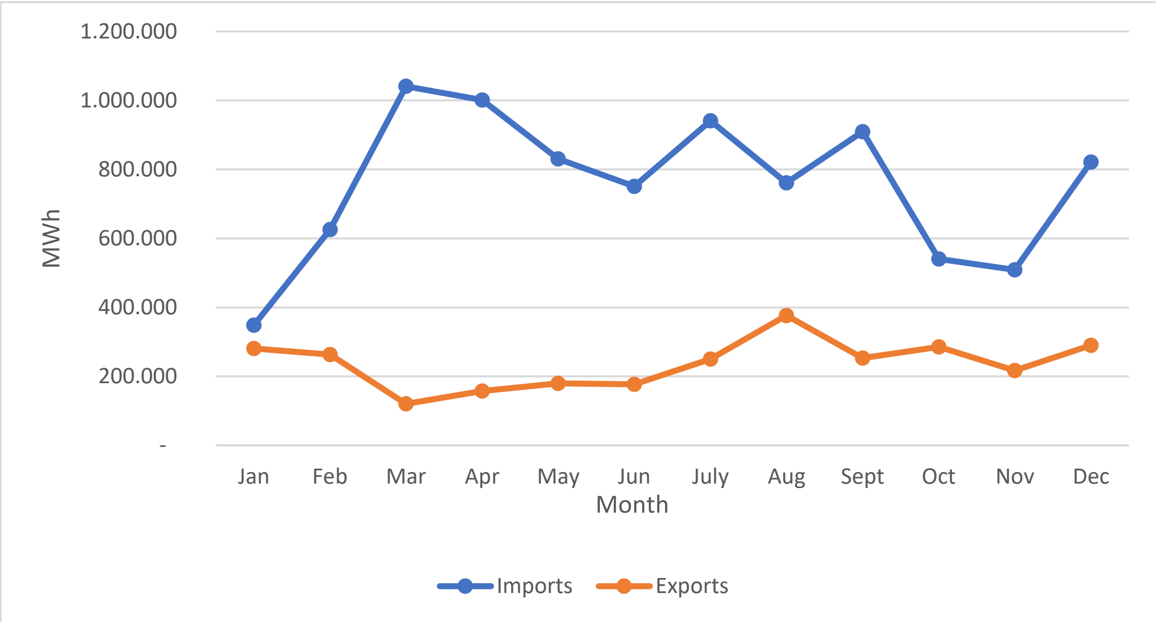


Figure 4: Cross-Border Electricity Trading in 2017

With the view to achieving the transition of the Greek electricity market to a European coupled market, as provided in the EU legislation for the single European electricity market integration and the achievement of the Target Model, Law 4425/2016 was adopted.

Pursuant to the authorization clause of paragraph 2 of article 6 of the Law 4425/2016, RAE issued Decision no. 67/2017 (OJ B ' 774 / 13.03.2017) on guidelines for the establishment of the Market Codes, as provided by this Law. In particular, according to the Decision no. 67/2017, in order to participate in the Wholesale Market of Forward Electricity Products, participants submit orders per portfolio, separate for purchase and sale, without explicit reference to a particular unit, load area or border.

In the Day Ahead Market, sell and buy orders will be submitted per unit in the case of Producers and per bidding zone or border for the rest. Especially, orders for RES injection and for Aggregators should be submitted per portfolio and load area. Aggregators shall make orders separately for sale and purchase. The Producers are required to submit sell orders for their total available capacity minus the quantities sold as Forward Electricity Products, in the organized Forward Market or OTC. In the Day Ahead Market simple and complex orders can be submitted.

To participate in the Intra-day market, participants submit orders per unit in the case of Producers and by bidding zone or border for the rest. Especially, orders for RES injection and for Aggregators should be submitted per portfolio and load area. Aggregators shall submit orders separately for sale and purchase. In Intra-day market, simple orders can be submitted.

Unit based central dispatch and production units' allocation by the Transmission System Operator is maintained as a basic principle to balance the System into this new design. To resolve the central dispatch problem, the dispatch period will be less than or equal to one hour (60 minutes). The pricing of balancing energy is based on the marginal pricing principle. The activated energy orders for reasons other than balancing energy (e.g. redispatching) are priced based on pay-as-bid principle while they do not set the electricity balancing marginal price. Finally, the Imbalance Settlement Period is set at 15 minutes.

On the basis of the provisions of Law 4425/2016 and Decision no. 67/2017 and with the support of Joint Research Center (JRC), the Detailed Level Design of the Hellenic Electricity Market, the compilation of the respective Market Codes and the high-level IT functional design specifications were commissioned to ECCO International, Inc with a view to efficiently operate the new electricity market and this project was completed in December 2017.

In parallel, in November 2017, JRC has commissioned a study to the Energy & Environmental Policy Laboratory of University of Piraeus regarding the selection of products supported by EUPHEMIA in the Greek Day-Ahead Market and the impact of imposing the minimum variable cost restriction on the producers' bids. This study should be completed by February 2018.

Further, the Ministry of Environment and Energy, in cooperation with the competent bodies published a draft law on the Energy Exchange, which was put in a public consultation from 01.12.2017 to 11.12.2017. The Greek Parliament on 15.01.2018 voted Law 4512/2018 for the establishment of an Energy Exchange (Government Gazette A 5 / 17.01.2018) which amends Law 4425/2016 and Law 4001/2011.

In this framework, for the implementation of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management, RAE issued the following Decisions within the year 2017:

- Decision no. 122/2017 "Decision on requesting for an amendment of the all TSOs' proposal on the Congestion Income Distribution Methodology (CIDM), in accordance with Article 73 of the Regulation (EU) 2015/1222, of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".

- Decision no. 123/2017 "Decision on requesting for an amendment of the NEMOs' proposal for the MCO plan".
- Decision no. 381/2017 "Decision on approval of the all TSOs' proposal for the Common Grid Model Methodology (CGMM), in accordance with Article 17 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".
- Decision no. 484/2017 "Decision on approval of the all TSOs' proposal on the Day Ahead Firmness Deadline (DAFD), in accordance with Article 69 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".
- Decision no. 491/2017 "Decision on requesting for an amendment of the all TSOs' proposal for the Intraday Cross-zonal Gate Opening & Gate Closure Times (IDCZGOT & IDCZGCT), in accordance with Article 59 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".
- RAE Decision No. 492/2017 "Decision on referral to ACER the adoption of the decision on the Congestion Income Distribution Methodology (CIDM), in accordance with Articles 73 and 9 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".
- Decision no. 533/2017 "Decision on approval of the NEMOs' proposal for the MCO plan, in accordance with Article 7 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".
- Decision no. 694/2017 "Decision on requesting for an amendment of the NEMOs and TSOs of CCR GRIT intraday coupling model proposal for Italian borders (CRIDA), pursuant to Article 63 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".
- Decision no. 695/2017 "Decision on requesting for an amendment of the NEMOs proposal for the products that can be taken into account by NEMOs in single day-ahead process (Products DA), according to the Article 40 (1) of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".
- Decision no. 696/2017 " Decision on requesting for an amendment to the NEMOs proposal for the products that can be taken into account by NEMOs in intraday coupling process (Products ID), in accordance with Article 53 paragraph 1 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".
- Decision no. 697/2017 "Decision on requesting for an amendment to the NEMOs proposal for the back-up methodology, according to Article 36 (3) of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".
- Decision no. 698/2017 "Decision on requesting for an amendment to the NEMOs proposal for the price coupling algorithm and continuous trading matching algorithm, in accordance with Rule 37 (5) of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".

- Decision no. 699/2017 "Decision on referral to ACER to decide on the NEMOs proposal for harmonised maximum and minimum clearing prices for Single Day Ahead Coupling (HMMP DA), pursuant to Article 41 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".
- Decision no. 700/2017 "Decision on referral to ACER to decide on the NEMOs proposal for harmonised maximum and minimum clearing prices for Single Intra Day Coupling (HMMP ID), in accordance with Article 54 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".
- Decision no. 874/2017 "Decision on approval of the all TSOs' proposal for amendment on the Determination of Capacity Calculation Regions, in accordance with Articles 15 and 9 paragraph 13 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".
- Decision no. 894/2017 "Decision on referral to ACER to decide on the all TSO's amended proposal for intraday cross-zonal gate opening and gate closure times, in accordance with Article 59 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".
- Decision no. 981/2017 "Decision on approval of the Greece-Italy TSOs proposal for fallback procedures, in accordance with Article 44 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".
- Decision no. 1034/2017 "Decision on requesting ACER to provide a six months extension for taking decision to the NEMOs and TSOs of CCR GRIT intraday coupling model proposal for Italian borders (CRIDA), pursuant to Article 63 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".
- Decision no. 1081/2017 "Decision on requesting for an amendment of the SEE CCR TSOs proposal for fallback procedures, in accordance with Article 44 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".

On 26 September 2016, Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation was adopted, which lays down detailed rules on cross-zonal capacity allocation in the forward markets, on the establishment of a common methodology to determine long-term cross-zonal capacity, on the establishment of a single allocation platform at European level offering long-term transmission rights, and on the possibility to return long-term transmission rights for subsequent forward capacity allocation or transfer long-term transmission rights between market participants.

RAE issued the following Decisions following the provisions of the aforementioned EU Regulation:

- Decision no. 794/2017 "Decision on referral to ACER to decide on the TSOs proposal for harmonised allocation rules for long-term transmission rights, in accordance with Article 51 of the Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation."

- Decision no. 855/2017 "Decision on approval of the GRIT CCR TSOs proposal for the regional specific requirements of the relevant capacity calculation region pursuant to Article 52 (3) (Annex 5), in accordance with Articles 52 (3) and 51 of the Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation".
- Decision no. 856/2017 "Decision on approval of the GRIT CCR TSOs proposal for the regional design of long-term transmission rights to be issued on each bidding zone border within the capacity calculation region, in accordance with Article 31 of the Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation".
- Decision no. 873/2017 "Decision on approval of the all TSOs' proposal for the establishment of a Single Allocation Platform (SAP) in accordance with Article 49 and for the cost sharing methodology in accordance with Article 59 of the Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation".
- Decision no. 895/2017 "Decision on referral to ACER to decide on the SEE CCR TSOs proposal for the regional specific requirements of the relevant capacity calculation region (Annex 10), in accordance with Articles 4 (par. 5, 7, 10), 52 (3) and 51 of the Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation".
- Decision no. 955/2017 "Decision on approval of the all TSOs' proposal for a single generation and load data provision methodology for delivering the generation and load data required to establish the common grid model for long-term time frames (GLDPM), in accordance with Article 17 of the Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation".
- Decision no. 1082/2017 "Decision on requesting for an amendment of the SEE CCR TSOs proposal for the regional design of long-term transmission rights to be issued on each bidding zone border within the capacity calculation region, in accordance with Article 31 of the Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation".

Moreover, Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing was adopted, which lays down a detailed guideline on electricity balancing including the establishment of common principles for the procurement and the settlement of frequency containment reserves, frequency restoration reserves and replacement reserves and a common methodology for the activation of frequency restoration reserves and replacement reserves.

RAE, within the framework of the EU Regulation 2017/2195, did not issue any decisions in 2017, as it was adopted at the end of the year, a matter to be addressed with the assistance of the relevant operators in 2018.

Monitoring TSO investment plans of NDP

Within 2016, RAE's Decision n. 280/2016 was adopted pursuant to the procedure of Art. 108 of Law 4001/2011 the NDP of the period 2017-2026. In 2017 RAE exercising its responsibilities to monitor the implementation of the projects included in the approved 2017-2026 NDP, in the framework of individual meetings with executives of ADMIE as well as through official correspondence with the Operator, and having in mind (a) the probability for the Operator not to meet the set timelines; and (b) the inadequate information already received, requested from ADMIE an analytical explanation regarding the progress of the works of the NDP.

Further to the above, ADMIE submitted in 2017 for approval the Preliminary Draft of the 2018 – 2027 NDP, which had already been put in public consultation. After a second round of public consultation by RAE in accordance with the provisions of Article 108 of Law 4001/2011, and based on the need to accelerate the interconnections of the Non-Interconnected Islands, to properly justify any delay, and analytically present all cost and benefit assumptions, ADMIE was requested to amend its proposal and resubmit it to RAE for approval (as was finally done in the beginning of 2018 and was approved by RAE Decision 256/2018).

Monitoring PCIs: In July 2016, the first file concerning the European Commission Regulation 347/2013 to RAE for the examination of an investment proposal of a project of common interest - PCI for the Israel - Cyprus - Greece electrical interconnection. This investment proposal included among others the implementation of an interconnection project between Crete and Attica, corresponding to that having been developed by ADMIE in the context of the approved 2014-2023 NDP, but also to the project of 2017-2026 NDP, submitted by ADMIE in 2016, and approved by the no. 280/2016 Decision of the Authority. The above submission did not constitute a complete request to launch the project evaluation process and, as RAE had informed the requested body, additional data had to be submitted regarding the project.

In January 2017 and September 2017, additional data were submitted to RAE and CERA over the investment request file, and following the latter the file considered complete, and automatically started the evaluation process. According to the relevant provisions, the evaluation of the request, together with the Cyprus Regulatory Authority (CERA) should be completed within six (6) months of the final submission of the complete files to the two authorities.

In October 2017, the Regulatory Authorities of Greece and Cyprus jointly issued the cross-border cost allocation (CBCA) decision based on the signing of a Memorandum of Understanding between ADMIE and EUROASIA INTERCONNECTOR LTD at the same period (RAE Decision 847/2017). The CBCA decision is a pre-requisite for applying for European funding in the framework of the Connecting Europe Facility (CEF).

3.2. Promoting Competition

3.2.1. Wholesale market

3.2.1.1. Description of the wholesale market

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

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

he Greek wholesale electricity market continues to operate as a day-ahead mandatory pool mechanism since its inception in 2005, to allow competition to emerge in a context with a severe constraint up to now. Regardless of the NOME mechanism and the turn of ADMIE to the OU model, the incumbent (PPC) remains dominant in both the generation and retail sectors, retaining exclusive access to cheap lignite and hydro resources, while retail prices, despite the gradual removal of cross-subsidies, were not linked to wholesale costs, but rather regulated at PPC's average cost, to transfer the benefit of the generator surplus to consumers. This combination of market features posed severe obstacles to new entry in the early years of market liberalization, giving a strong signal for upcoming capacity shortages in the following years.

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

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

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

In the non-interconnected islands, 32 (current;y 29) autonomous power systems currently operate without any wholesale electricity market. In all these autonomous power systems, the Public Power Corporation (PPC) is the only conventional power producer using oil and heavy diesel as a fuel. There are several RES power producers (including a PPC subsidiary) but only one existing supplier (PPC) in all islands, except Crete where the market is open to other suppliers. The network operator in the non - interconnected islands is DEDDIE S.A. (Hellenic Distribution Network Operator). In the non - interconnected 32 (currently 29) autonomous systems, neither producers nor suppliers submit daily offers for their production or for their customers loads thus, there is no system marginal price but an estimated clearance price of energy. The estimation is done monthly, based on the variable cost of the conventional power units for each of all these autonomous power systems, pursuant to Law 4001/2011 and the code of micro-grid operation of the non - interconnected islands, PPC as the only supplier buys all electricity including RES.

3.2.1.2. Installed Capacity and Generation

According to the data presented in Table 13, in 2016, there was a small decrease in the lignite installed generation capacity from 4,462MW (in 2015) to 4.337MW and the final closure of the oil generation units of PPC (730MW). For the same period, installed generation capacity of RES presented a small increase, from 4,763MW in 2015 to 4,871MW in 2016 (see Table 13). In 2017, RES amounted to a total of 5,138MW, which is in particular the result of the increase in wind farm capacity, i.e. 255MW. In 2017, total installed capacity, including renewables, reached 17,128MW.

The information presented below is based on the Monthly Energy Balance Reports publicity available at TSO's site (http://www.admie.gr/en/market-statistics/montlhy-energy-balance/) and the TSO's TYNDP.

Table 11: Installed Capacity by Producer/Fuel			
By producer/fuel	**Installed Capacity 2017 (MW)**	**Installed Capacity 2016 (MW)**	**Installed Capacity 2015 (MW)**
PPC Lignite	4,337	4,337	4,462
PPC Hydro	3,170.7	3,017.7	3,017.7
PPC CCGT	1,856.7	1,856.7	1,856.7
PPC OCGT	0	0	160
Elpedison CCGT	830	830	830
Heron II CCGT	432	432	432
Korinthos Power CCGT	436.6	436.6	436.6
Protergia CCGT	444.5	444.5	444.5
Heron I OCGT	148.5	148.5	148.5
Alouminion CHP	334	334	334
PPC Oil	0	0	730
Total Thermal + Large Hydro	11,990	11,837	12,852
Renewables + high eff CHP	5,138	4,871	4,763
Total	17,128	16,708	17,615

Table 12: Installed Capacity by Fuel			
By fuel	**Installed Capacity 2017 (MW)**	**Installed Capacity 2016 (MW)**	**Installed Capacity 2015 (MW)**
Lignite	4,337	4,337	4,462
Natural Gas	4,482.3	4,482.3	4,642.3
Oil	0	0	730
Hydro	3,170.7	3,017.7	3,017.7
RES+ high eff CHP	5,138	4,871	4,763
Total	17,128	16,708	17,615

Table 13: Installed Capacity and Production by fuel, including RES, in 2017				
Installed capacity and production by fuel, in 2017	**Installed capacity (MW)**	**Total annual production (GWh)**	**Share in produced volume (%)**	**Share in produced volume, including RES (%)**
Lignite	4,337	16,387	46%	36%
Hydro	3,170.7	3,457	10%	8%
Natural gas	4,482.3	15,397	44%	34%
Total Thermal + Large Hydro (1)	11,990	35,240	100%	78%
Total RES (Grid + Network) (2)	5,138	10,564		23%
Total (1+2)	17,128	45,805		100%

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total
Lignite	1708	1573	1331	1129	1080	1215	1466	1346	1202	1460	1529	1347	16387
Natural Gas	2001	1240	764	764	972	1417	1500	1603	1223	1111	1442	1361	15397
Hydro	658	214	218	146	210	284	406	362	214	196	234	315	3457
RES	770	839	959	838	960	729	988	1168	772	839	681	1022	10564
Total	5137	3867	3272	2878	3222	3644	4359	4479	3411	3606	3886	4044	45805

Table 14: Monthly production by Generation fuel in Greece in 2017

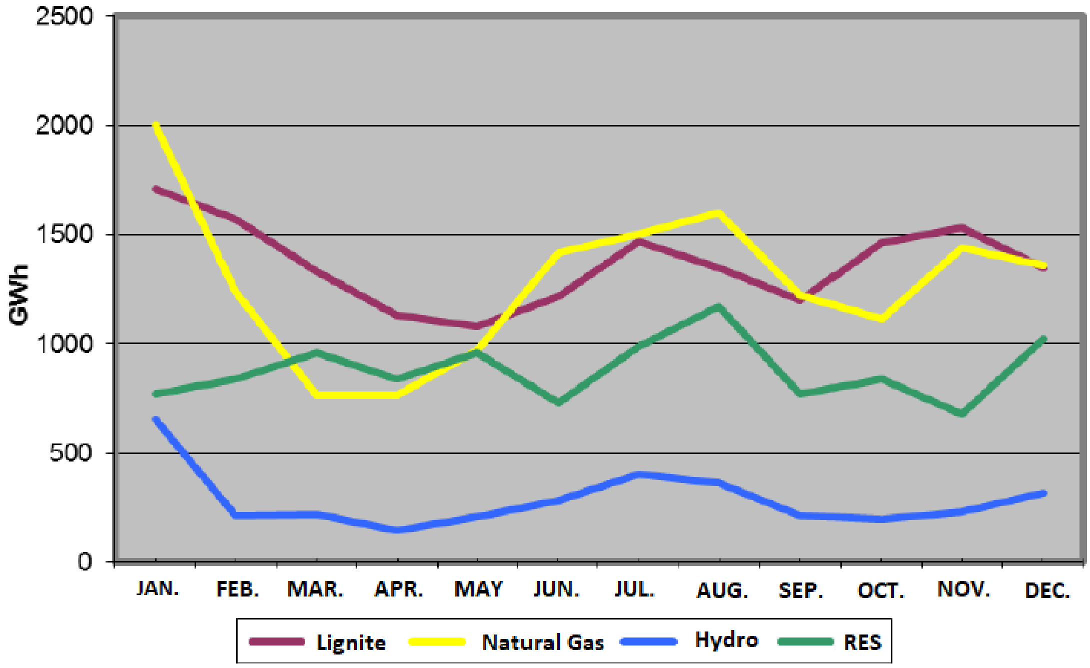


Figure 5: Monthly Production by Generation Fuel in 2017

In 2017, electricity demand has shown a very strong increase in percentage points on a monthly basis during January and February (12.3% and 6.8%, respectively, compared to the corresponding months of the previous year). This, as mentioned above, is related to the electrification of heating along with the great drop in temperature and the intense weather deterioration during these two months, in comparison to the corresponding months of the previous year, which on the contrary were the warmest of the last 100 years in Greece. On the other hand, in December 2017 there was a significant reduction in electricity demand of 6.2% in relation to December 2016. This is mainly due to the relatively mild temperatures, which prevented to a certain extent the frequent use of electric heaters.

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

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

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

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

Table 15: Day ahead market schedule and imbalances positions settlement of the market participants									
	DAY AHEAD SCHEDULE			IMBALANCES			TOTAL		
NAME	**QUANTITY (MWh)**	**AMOUNT (€)**	**price (€/MWh)**	**QUANTITY (MWh)**	**AMOUNT (€)**	**Price €/MWh**	**METERED PRODUCTION (MWh)**	**TOTAL AMOUNT (€)**	**AVERAGE PRICE (€/MWh)**
ELPEDISON S.A (CCGT)	2,686,973	156,408,604	58.2	-5,056	-6,395,410	1264,9	2,730,633	150,013,194	54.9
PROTERGIA POWER S.A. (CCGT)	1,653,241	55,727,604	57.5	20,073	-1,095,630	-54,6	949,730	54,631,974	57.5
ALUMINIUM S.A.	575,499	30,550,478	53.1	-24,547	-2,240,570	91,3	600,638	28,309,908	47.1
PPC	27,612,616	1,602,022,184	58.0	602,193	14,974,924	24,9	27,499,297	1,616,997,108	58.8
HERON I (CCGT)	4,160	451,340	108.5	-14,547	-2,095,016	144,0	18,717	-1,643,676	-87.8
HERON II (CCGT)	1,170,412	71,505,985	61.1	4,919	-2,009,279	-408,5	1,167,861	69,496,706	59.5
KORINTHOS POWER A.E. (CCGT)	1,757,791	103,717,446	59.0	29,255	-2,201,392	-75,2	1,731,266	101,516,054	58.6
MYTILINEOS	1,653,241	95,464,448	57.7	31,739	-580,035	-18,3	1,623,624	94,884,413	58.4
TOTAL	**36,429,067**	**2,115,848,088**	**58.1**	**644,029**	**-1,642,408**	**-2,6**	**36,321,765**	**2,114,205,680**	**58.2**

PRODUCERS 2017	**DAY AHEAD**			**IMBALANCES**			**TOTAL**		
PARTICIPANTS	**MWh**	**€**	**€/MWh**	**MWh**	**€**	**€/MWh**	**MWh**	**€**	**€/MWh**
ALUMINIUM OF GREECE BEAE	575.498,614	30.550.478,182	53,09	-24.547,013	-2.240.570,314	91,28	600.638,213	28.309.907,868	47,13
ELPEDISON S.A.	2.686.972,869	156.408.603,552	58,21	-5.056,190	-6.395.410,011	1264,87	2.730.632,982	150.013.193,540	54,94
HERON THERMO S.A.	4.159,753	451.339,511	108,50	-14.547,222	-2.095.016,401	144,01	18.716,663	-1.643.676,890	-87,82
HERON II VIOTIAS S.A.	1.170.411,572	71.505.984,683	61,09	4.919,207	-2.009.279,450	-408,46	1.167.860,756	69.496.705,233	59,51
CORINTH POWER S.A.	1.757.790,994	103.717.446,166	59,00	29.254,830	-2.201.391,749	-75,25	1.731.265,588	101.516.054,417	58,64
MITILINEOS S.A.	1.653.241,123	95.464.448,230	57,74	31.739,411	-580.035,085	-18,27	1.623.623,965	94.884.413,144	58,44
PPC S.A.	27.612.615,816	1.602.022.184,239	58,02	602.192,917	14.974.924,111	24,87	27.499.297,188	1.616.997.108,350	58,80
PROTERGIA AGIOS NIKOLAOS POWER S.A.	968.376,648	55.727.603,744	57,55	20.072,978	-1.095.629,595	-54,58	949.729,960	54.631.974,149	57,52
TOTAL	**36.429.067,391**	**2.115.848.088,307**	**58,08**	**644.028,918**	**-1.642.408,495**	**-2,55**	**36.321.765,315**	**2.114.205.679,812**	**58,21**

Table 16: Producing companies participating in electricity market

LOAD REPRESENTATIVES 2017	DAY AHEAD			IMBALANCES			TOTAL		
PARTICIPANTS	MWh	€	€/MWh	MWh	€	€/MWh	MWh	€	€/MWh
ELPEDISON S.A.	1.716.985,191	97.122.736,973	56,57	-31.541,620	-2.156.261,584	68,36	1.685.443,572	94.966.475,389	56,35
HELLENIC POST S.A.	53.288,849	3.089.179,126	57,97	-3.459,339	-231.195,142	66,83	49.829,510	2.857.983,985	57,36
GAS THESSALONIKIS-THESSALIAS S.A.	459,521	26.636,031	57,96	-190,593	-11.304,030	59,31	268,928	15.332,001	57,01
GREEK ENVIRONMENTAL & ENERGY NETWORK S.A.	252.323,295	14.104.169,041	55,90	-19.726,539	-1.028.257,409	52,13	232.596,757	13.075.911,632	56,22
GREENSTEEL-CEDALION COMMODITIES S.A.	50,152	2.821,417	56,26	19,416	1.185,106	61,04	69,057	4.006,523	58,02
ECONOMIC GROWTH S.A.	18.966,918	1.026.252,527	54,11	-5.236,160	-288.334,540	55,07	13.730,758	737.917,987	53,74
HERON	1.709.646,176	96.307.882,767	56,33	-56.405,029	-3.711.424,239	65,80	1.653.241,147	92.596.458,528	56,01
INTERBETON S.A.	24.568,559	1.385.700,853	56,40	-861,942	-49.683,737	57,64	23.706,616	1.336.017,117	56,36
KEN S.A.	47.441,480	2.703.312,257	56,98	-6.932,905	-369.614,703	53,31	40.508,575	2.333.697,554	57,61
CORINTH POWER S.A.	256,000	9.447,589	36,90	4.734,539	248.269,976	52,44	4.990,539	257.717,565	51,64
MITILINEOS S.A.	905.357,767	51.879.705,827	57,30	-26.779,794	-1.567.277,662	58,52	878.577,972	50.312.428,165	57,27
NOVAERA ENERGY S.A.	16.998,353	954.620,216	56,16	-879,245	-12.980,574	14,76	16.119,108	941.639,641	58,42
NRG TRADING HOUSE S.A.	476.759,592	26.402.905,561	55,38	-54.162,978	-2.875.215,352	53,08	422.596,615	23.527.690,209	55,67
OTE estate	125.133,357	7.038.647,066	56,25	-18.274,965	-1.027.628,932	56,23	106.858,392	6.011.018,134	56,25
PPC S.A.	44.369.550,543	2.496.772.729,387	56,27	-417.007,052	-19.433.546,818	46,60	43.952.543,491	2.477.339.182,569	56,36
PPC S.A. (SUPPLIER OF TOTAL SERVICE)	65.203,507	3.594.589,236	55,13	30.563,952	2.047.558,153	66,99	95.767,460	5.642.147,390	58,92
PROTERGIA AGIOS NIKOLAOS POWER S.A.	798.711,787	43.485.038,888	54,44	4.160,188	363.814,496	87,45	802.871,975	43.848.853,384	54,62
VI.ENER S.A.	28.360,832	1.541.280,623	54,35	-7.289,374	-396.131,271	54,34	21.071,458	1.145.149,353	54,35
VOLTERRA S.A.	399.048,215	22.046.248,010	55,25	-39.890,271	-1.959.040,948	49,11	359.157,944	20.087.207,062	55,93
VOLTON S.A.	18.299,432	1.054.871,025	57,65	-3.617,411	-210.961,923	58,32	14.682,020	843.909,102	57,48
WATT AND VOLT S.A.	573.460,463	32.109.427,761	55,99	-26.671,449	-1.424.039,929	53,39	546.789,014	30.685.387,832	56,12
TOTAL	**51.600.869,990**	**2.902.658.202,181**	**56,25**	**-679.448,571**	**-34.092.071,059**	**50,18**	**50.921.420,907**	**2.868.566.131,121**	**56,33**

Table 17: Load Representatives 2017

IMPORTERS 2017	DAY AHEAD			IMBALANCES			TOTAL		
PARTICIPANTS	MWh	€	€/MWh	MWh	€	€/MWh	MWh	€	€/MWh
ALPIQ ENERGY SE	215.054,992	10.714.548,273	49,82	-706,000	34.368,074	-48,68	221.083,000	10.748.916,347	48,62
AXPO ENERGY ROMANIA S.A.	97.776,499	4.866.784,813	49,77	-10,000			100.175,000	4.866.784,813	48,58
AYEN ENERGIJA d.o.o.	12,672	575,842	45,44				13,000	575,842	44,30
CEZ A.S.	6.957,887	348.251,556	50,05				7.138,000	348.251,556	48,79
DANSKE COMMODITIES A/S	591.271,323	31.528.796,036	53,32	-35,000			603.156,000	31.528.796,036	52,27
DENCO S.R.L.	20,000	1.171,400	58,57				20,000	1.171,400	58,57
EDELWEISS ENERGIA S.P.A.	21.660,000	1.145.271,280	52,87				21.660,000	1.145.271,280	52,87
EDISON TRADING S.P.A	122.816,935	6.104.871,034	49,71	-10,000			124.899,000	6.104.871,034	48,88
ELEKTRICNI FINANCNI TIM d.o.o.	223.398,455	11.717.876,360	52,45	-86,000			227.808,000	11.717.876,360	51,44
ELECTRADE S.p.A.	20.856,633	1.016.485,157	48,74				20.856,000	1.016.485,157	48,74
ELPEDISON A.E.	333.550,832	17.017.951,690	51,02	-40,000			341.022,000	17.017.951,690	49,90
ENSCO S.A.	243.350,739	12.647.785,272	51,97	-8,000			246.445,000	12.647.785,272	51,32
EUNICE TRADING S.A.	19.594,544	948.815,195	48,42				20.069,000	948.815,195	47,28
EVN TRADING SOUTH EAST EUROPE EAD	18.726,023	943.889,963	50,41	-20,000			19.207,000	943.889,963	49,14
EZPADA S.R.O.	234.195,233	12.060.433,259	51,50	633,000	35.490,930	56,07	235.704,000	12.095.924,189	51,32
GEN -I ATHENS M.E.Π.E (SMLLC)	2.272.977,969	118.550.927,369	52,16	1.454,000	96.170,327	66,14	2.312.338,000	118.647.097,696	51,31
GREEK ENVIRONMENTAL & ENERGY NETWORK S.A.	333.553,088	17.222.266,123	51,63	-83,000	1.242,780	-14,97	340.372,000	17.223.508,903	50,60
GROUP TRANS ENERGY OOD	109.539,829	5.495.480,357	50,17	-50,000			112.794,000	5.495.480,357	48,72
HERON THERMO S.A.	348.232,041	18.406.964,435	52,86	-45,000			356.767,000	18.406.964,435	51,59
HOLDING SLOVENSKE ELEKTRARNE D.O.O.	492.148,275	24.382.115,407	49,54	-188,000	8.546,172	-45,46	502.504,000	24.390.661,579	48,54
INTERBETON S.A.	19.690,822	975.985,094	49,57	-5,000			20.184,000	975.985,094	48,35
LE TRADING A.S.	1.118,901	58.205,960	52,02				1.146,000	58.205,960	50,79
MITILINEOS S.A.	114.908,162	6.204.734,320	54,00	-45,000			116.643,000	6.204.734,320	53,19
NECO S.A.	75.087,500	3.780.393,946	50,35				75.088,000	3.780.393,946	50,35
NOVAERA ENERGY S.A.	3.426,995	166.376,968	48,55	-20,000			3.468,000	166.376,968	47,97
NRG TRADING HOUSE S.A.	300.051,420	15.898.272,415	52,99	-20,000			304.562,000	15.898.272,415	52,20
Nvalue AG	4.362,667	220.652,461	50,58				4.363,000	220.652,461	50,57
PPC S.A.	1.857.490,620	99.237.320,836	53,43	-215,000	4.518,008	-21,01	1.900.686,000	99.241.838,844	52,21
PROTERGIA AGIOS NIKOLAOS POWER S.A.	124.123,936	6.347.087,194	51,14	-120,000			126.014,000	6.347.087,194	50,37
SENTRADE S.A.	40.518,056	2.040.751,048	50,37				41.535,000	2.040.751,048	49,13
STATKRAFT MARKETS GMBH	113.384,721	5.749.921,467	50,71	542,000	60.302,424	111,26	114.880,000	5.810.223,891	50,58
TERNA ENERGY ABETE	65.534,690	3.494.037,625	53,32	16,000	1.450,955	90,68	67.307,000	3.495.488,581	51,93
VOLTERRA S.A.	163.240,840	8.529.228,320	52,25	-60,000			165.004,000	8.529.228,320	51,69
WATT AND VOLT S.A.	318.711,976	16.229.384,603	50,92	145,000	9.907,886	68,33	325.895,000	16.239.292,489	49,83
TOTAL	**8.907.345,275**	**464.053.613,078**	**52,10**	**1.024,000**	**251.997,556**	**246,09**	**9.080.805,000**	**464.305.610,634**	**51,13**

Table 18: Importing Companies in 2017

EXPORTERS 2017	DAY AHEAD			IMBALANCES			TOTAL		
PARTICIPANTS	**MWh**	**€**	**€/MWh**	**MWh**	**€**	**€/MWh**	**MWh**	**€**	**€/MWh**
ALPIQ ENERGY SE	55.675,085	3.225.926,330	57,94	162,000	42.816,112	264,30	55.837,000	3.268.742,442	58,54
AXPO ENERGY ROMANIA S.A.	21.658,000	1.384.935,539	63,95	75,000	8.792,485	117,23	21.733,000	1.393.728,024	64,13
DANSKE COMMODITIES A/S	508.708,323	29.674.712,620	58,33	4,000	226,940	56,74	508.713,000	29.674.939,560	58,33
DENCO S.R.L.	1.476,306	77.039,976	52,18				1.476,000	77.039,976	52,20
DUFERCO ENERGIA S.P.A.	695,000	34.192,422	49,20				695,000	34.192,422	49,20
EDELWEISS ENERGIA S.P.A.	410,000	24.519,480	59,80				410,000	24.519,480	59,80
EDISON TRADING S.P.A	10.907,754	546.016,510	50,06				10.908,000	546.016,510	50,06
ELEKTRICNI FINANCNI TIM d.o.o.	262.904,211	15.624.561,293	59,43	5,000	1.320,885	264,18	262.909,000	15.625.882,178	59,43
ELECTRADE S.p.A.	1.679,000	88.786,500	52,88				1.679,000	88.786,500	52,88
ELPEDISON S.A.	42.282,000	2.151.544,511	50,89				42.282,000	2.151.544,511	50,89
ENSCO S.A.	41.715,011	2.257.336,280	54,11				41.714,000	2.257.336,280	54,11
EVN TRADING SOUTH EAST EUROPE EAD	21.071,000	1.556.208,949	73,86				21.071,000	1.556.208,949	73,86
EZPADA S.R.O.	171.875,341	9.688.570,973	56,37				171.874,000	9.688.570,973	56,37
GEN -I ATHENS M.E.P.E (SMLLC)	965.493,568	55.687.122,097	57,68	5.918,000	379.076,210	64,05	971.408,000	56.066.198,307	57,72
GREEK ENVIRONMENTAL & ENERGY NETWORK S.A.	102.826,241	6.037.869,672	58,72	36,000	2.270,966	63,08	102.863,000	6.040.140,638	58,72
GROUP TRANS ENERGY OOD	4.941,000	305.464,872	61,82				4.941,000	305.464,872	61,82
HERON THERMO S.A.	66.265,000	3.313.321,649	50,00	7,000	400,000	57,14	66.272,000	3.313.721,649	50,00
HOLDING SLOVENSKE ELEKTRARNE D.O.O.	47.805,563	2.728.533,081	57,08	68,000	4.503,352	66,23	47.874,000	2.733.036,433	57,09
KEN A.E.	20.406,000	1.140.663,764	55,90				20.406,000	1.140.663,764	55,90
LE TRADING A.S.	206,000	10.463,767	50,79				206,000	10.463,767	50,79
MITILINEOS	52.848,117	2.855.598,942	54,03				52.848,000	2.855.598,942	54,03
NECO S.A.	3.880,000	216.035,429	55,68				3.880,000	216.035,429	55,68
NOVAERA ENERGY S.A.	172,000	12.381,418	71,98				172,000	12.381,418	71,98
NRG TRADING HOUSE S.A.	186.182,338	10.438.813,182	56,07	-97,000	112,940	-1,16	186.087,000	10.438.926,122	56,10
Nvalue AG	100,000	6.400,000	64,00				100,000	6.400,000	64,00
PPC S.A.	14.589,738	763.589,608	52,34				14.590,000	763.589,608	52,34
PROTERGIA AGIOS NIKOLAOS POWER S.A.	29.137,829	1.446.673,461	49,65	10,000	467,610	46,76	29.149,000	1.447.141,071	49,65
SENTRADE S.A.	9.321,000	588.612,984	63,15				9.321,000	588.612,984	63,15
STATKRAFT MARKETS GMBH	46.228,000	2.753.311,202	59,56				46.228,000	2.753.311,202	59,56
TERNA ABETE	42.176,000	2.451.967,408	58,14	442,000	60.866,321	137,71	42.618,000	2.512.833,729	58,96
VOLTERRA S.A.	17.937,309	893.828,241	49,83				17.937,000	893.828,241	49,83
WATT AND VOLT S.A.	93.344,000	4.863.900,898	52,11	3,000	152,914	50,97	93.347,000	4.864.053,812	52,11
TOTAL	**2.844.916,734**	**162.848.903,058**	**57,24**	**6.633,000**	**501.006,735**	**75,53**	**2.851.548,000**	**163.349.909,793**	**57,28**

Table 19: Exporting companies in 2017

3.2.1.3. Auxiliary and Generation capacity reserves mechanisms (market)

The Transitory Flexible Remuneration Mechanism (TFRM), which was elaborated and was approved by the European Commission in 2016 was terminated by the end of April 2017 according to the provisions of the Decision of the European Commission (SA 38968 /2015/N). The aim of this mechanism was to compensate electricity generators in the interconnected system for the provision of "flexibility services" to the TSO. In particular, on instruction form the TSO and subject to a specified notice period, beneficiaries increased or decreased the amount of electricity injected into the electricity system at a specified minimum rate on a multi-hour time-scale. The scheme entered into force for a period of 12 months, from 01.05.2016 to 30.04.2017 and the level of remuneration was set administratively to 45,000 €/MW/year. In 2017 RAE issued Decision 346/2017 for the amendment of the provisions of System Operation Code (Government Gazette B103 / 31.01.2012) and the Market Clearance Manual for the implementation of the Methodology for the imposition of sanctions (Government Gazette B1655 / 15.05.2017), for the implementation of the TFRM.

In view of the expiry of the Transitional Flexibility Remuneration Mechanism (TFRM), and taking into account the continuing needs of the System for flexibility until the full implementation of the Target Model, RAE, within its remit to monitor the security of the energy supply of the country (No.

12 N.4001 / 2011), assessed the need to adopt a new flexibility remuneration mechanism. In this context, RAE asked from ADMIE the elaboration and submission of a Flexibility Needs Study for the period 2018- 2027. Based on the findings of this study, RAE proceeded to an inventory of the basic principles of the new mechanism, called Transitory Flexible Capacity Remuneration Mechanism ("FCRM"), which were put in a public consultation in June 2017. This proposed mechanism, given its transitory nature, resembles the basic parameters of its predecessor. However, an essential differentiation point is the introduction of a competitive tendering procedure for the determination of the compensation. RAE provided technical support to the Greek authorities to submit this mechanism to the European Commission and, following its evaluation and approval, RAE within the framework of its competencies and related legislation authorization will make the necessary modification and specialization of the regulatory framework to secure its credible and workable implementation of this mechanism to the benefit of the country's security of supply.

Provisions of Balancing Services

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

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

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

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

During 2017, RAE initiated the procedure for the redefinition, and notably the significant increase of the existing Administrative Defined Maximum Offer Price to provide Primary and Secondary Reserves (from the current price of 10 € / MWh to 50 € / MWh).

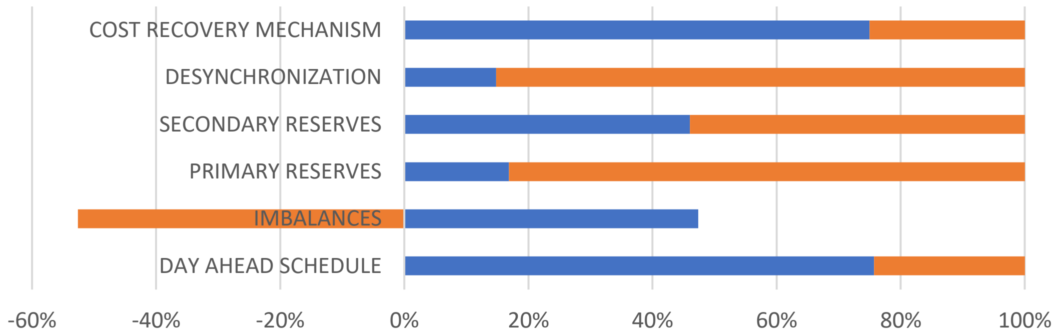
3.2.1.4. Market Settlement

2017 was the seventh year of the implementation of the market design that allowed for the settlement of imbalances, and the fourth year of the reform package for the wholesale market, as described above. The remuneration through the day-ahead market represented 94% compared to 87% of generators' cash flows, as compared to 97% in 2015, to 77% in 2014 and 63% in 2013. At cash flow level, the revenues of conventional technology producers amounted to € 2.1 billion in 2017, showing a sharp increase compared to 2016, which amounted to € 1.46 billion. In 2017, their revenue increased both for PPC and for Independent Producers. The ex-post clearances carried out by ADMIE amounted to € 0.11 billion compared to € 0.23 billion in 2016. That is, total value in the wholesale market in 2017 reached € 2.22 billion.

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

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

Figure 6: Generators' Revenue by Source (in mil. And in %)



	DAY AHEAD SCHEDULE	IMBALANCES	PRIMARY RESERVES	SECONDARY RESERVES	DESYNCHRONIZ ATION	COST RECOVERY MECHANISM
PPC	1602,02	14,97	0,0814	0,7	7,32	28,09
IPPs	513,83	-16,62	0,4015	0,82	42,08	9,36

PPC IPPs

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

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

3.2.1.5. Market Size with respect to Quantity

Day Ahead Scheduling (DAS) is the model for organization and operation of the domestic wholesale market through which all electricity produced is traded, consumed and will be delivered the following day to its Interconnected Electrical System (excluding the non-interconnected islands in which market organization differs).

In this model, value determination is the result of a complex algorithmic application (object-oriented optimization function) which seeks to minimize the cost of allocating production units, based on technical information on their operation and the System. The algorithm requires the introduction of the predicted values for the next day on an hourly basis (such as demand, availability of conventional units, RES production, cross-border flows, etc.). The solution also includes several parameters, which are either under regulating or objecting control by RAE.

DAS model includes the mandatory bids submitting of producers for their full power produced and, respectively, bidding for the total demand from suppliers, without allowing bilateral physical delivery contracts between producers and suppliers. This means that all energy transactions are mandatory through the DAS (model mandatory pool).

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 52.043TWh in 2017 (51.21TWh in 2016), reflecting a marginal increase of 1.4% relative to 2016.

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

Peak demand occurred in July 2017 (overall demand, taking into account the pumping, and the estimated demand in the distribution network that was covered by the production of that network) was recorded on 13.07.2017, the 14th hour of allocation, with 9,674 MW, compared with 9,135 MW in July 2016. This is the annual price maximum, unlike the previous year during which the annual maximum was observed in December. However, it is worth noting that high demand was recorded also in January 2017, reaching 9,495 MW.

Table 20: Monthly electricity Demand

	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	Total
Real Consumption (GWh), in 2017	5,206	4,228	4,196	3,721	3,872	4,224	5,047	4,862	4,066	3,848	4,174	4,599	52,043
Consumption at the Grid level (GWh), in 2017	4,964	3,901	3,750	3,246	3,408	3,774	4,564	4,379	3,668	3,457	3,909	4,291	47,313
Real Consumption in 2016 (GWh)	4,634	3,957	4,178	3,671	3,739	4,420	5,098	4,718	3,938	3,861	4,096	4,902	51,212
Difference between real consumption in (2017-2016) (GWh)	572	271	18	50	133	-196	-51	144	128	-13	78	-303	831
% change in real consumption (2017-2016)	12,3	6,8	0,4	1,4	3,6	-4,4	-1,0	3,0	3,3	-0,3	1,9	-6,2	1,6

December 2017 Monthly Report TSO ADMIE (including pump hydro storage)

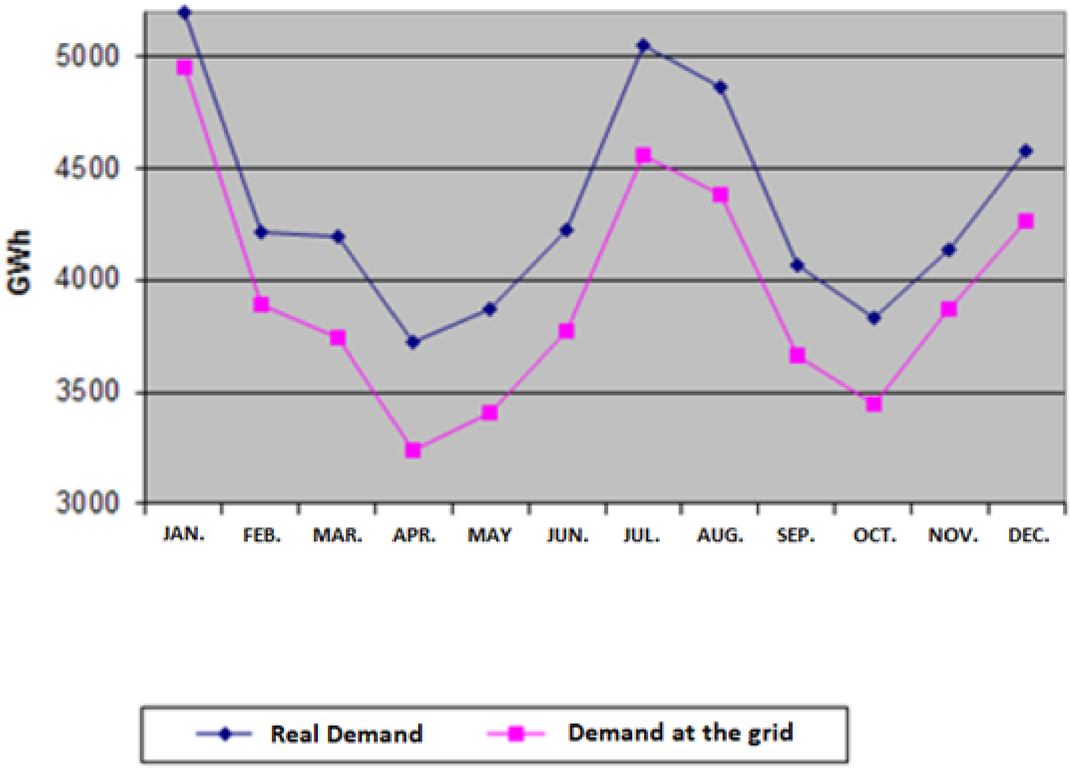


Figure 7: Monthly Electricity Demand in 2017

It is noteworthy that real consumption has shown a very strong increase, on a monthly basis the percentage during January and February reached 12.17% and 6.55%, respectively, compared to the corresponding months of the previous year). This, as mentioned above, is also related to the great drop in temperature and the intense weather deterioration during these two months of 2017, compared to the corresponding months of the previous year, when there were extremely high temperatures for the season (indeed, it is mentioned in many sources that these two months were of the warmest of the last 100 years). In contrast, in December 2017 there was a significant reduction in real consumption of 6.69% in relation to December 2016. This is largely due to the relatively mild temperatures for the time, which prevented to a certain extent the frequent use of electric heaters.

As for the impact of the economic recession on domestic industrial production, it is encouraging that in 2017 the consumption of High Voltage customers continued to have a recovery trend for the third consecutive year (2.96% compared with 3.76% in 2016 and 0.47% in 2015), almost in all months. The highest a rise on a monthly basis was observed in May 2017 and was equal to 5.73%, while the maximum annual price was in the same month and was 646 GWh compared to 621 GWh in 2016 and 589 GWh in 2015.

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

3.2.1.6. Monitoring market shares

Figures 1, 2 and 3 show the installed net capacity per technology (including RES) and producer (excluding RES) in the interconnected system, during 2017, respectively. Accordingly, Figure 4 shows the share of electricity generation per producer, excluding RES, during 2017. The data are based on the Monthly Energy Balance Reports publicity available at TSO’s site [http:// www.admie.gr] and the TSO’s TYNDP. As can be seen, the dominant market player in Greece is the Public Power Corporation (PPC); in terms of installed capacity, PPC owns and operates about 8,9 GW of thermal and hydroelectric power plants, representing 77% of total generating capacity, excluding RES. Private producers currently possess seven (7) thermal power units with a total net capacity of approximately 2,6 GW. Their ownership structure is presented below:

- Enthess (400,3 MW) and Thisvi (410 MW), both being Gas-fired Combined Cycle Thermal Power Plants – CCGT, owned by Elpedison S.A.
- Heron II (422,1 MW – CCGT) and Heron I (147,8 MW, Open Cycle Gas Turbine – OCGT), owned by Heron S.A.
- Protergia (432,7 MW – CCGT), Korinthos Power (433,5 MW – CCGT) and Alouminion (334 MW, large-scale Gas-fired Combined Heat and Power Plant – CHP), owned by Mytilinaios Group.

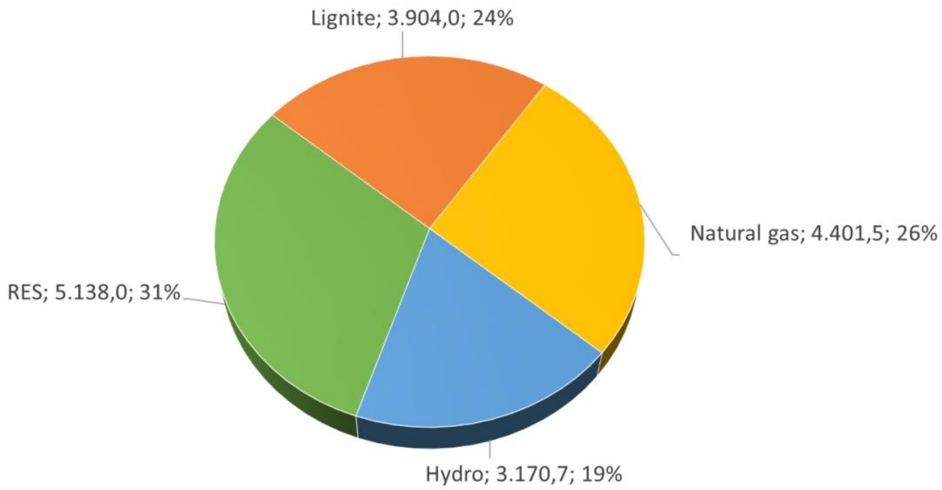


Figure 8: Installed (net) capacity (MW and as a percentage of total capacity) per technology in 2017

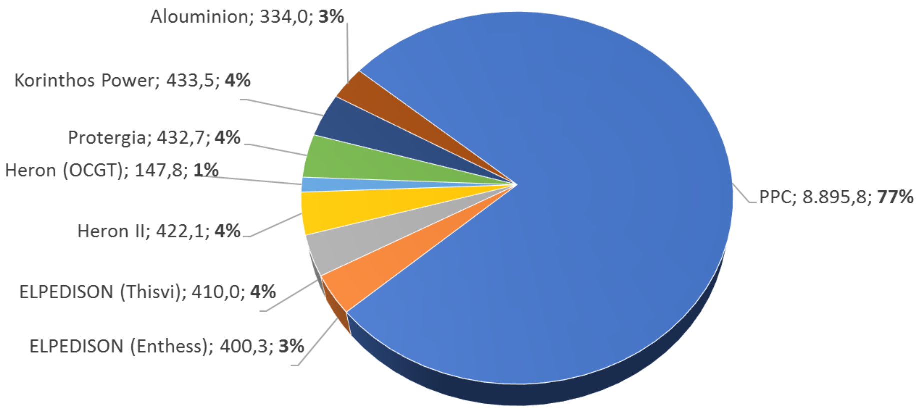


Figure 9: Installed (net) capacity (MW and as a percentage of total capacity) of power units in 2017, excluding RES

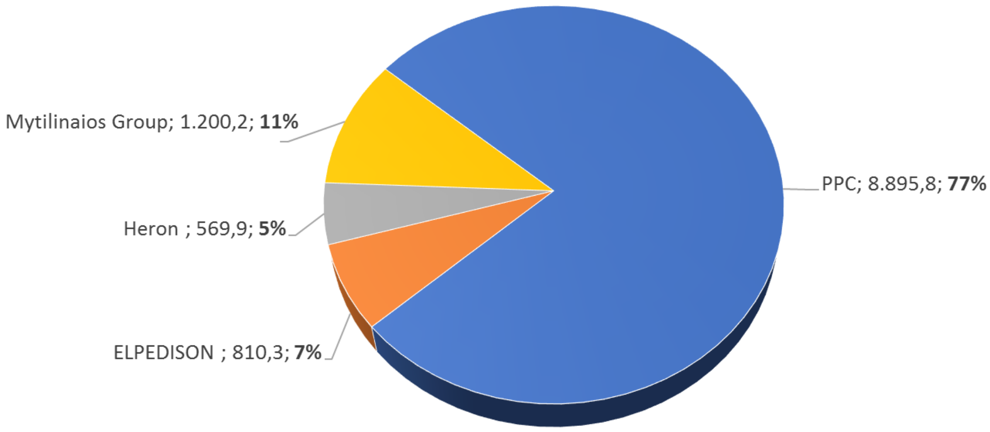


Figure 10: Installed (net) capacity (MW and as a percentage of total capacity) per producer in 2017, excluding RES

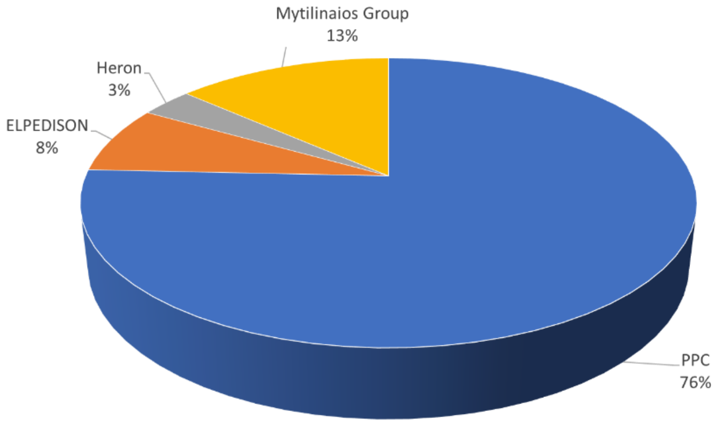


Figure 11: Electricity generation (%) per producer in 2017, excluding RES

Moreover, two (2) additional thermal units, of 851 MW total capacity had also applied for connection. This capacity includes the incumbent's new CCGT unit Megalopoli V (811MW), which is expected to be in full operation mode in 2018. 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 (153 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.

It is noteworthy that, in the interconnected system, the total power of the units of natural gas exceeds the respective power of lignite units; most of the power generation capacity by natural gas units is owned by producers other than PPC S.A. This development is the result of the strong investment incentives that have been provided since 2006 through the Capacity Remuneration Mechanism, in order to address the serious power shortages Greece was experiencing that period, before the onset of the financial crisis, as well as the market opening achievement, and the state's choice not to invest in coal-based units. In addition, the withdrawal of obsolete lignite, petroleum and gas units in the year 2016 has significantly influenced the electricity mix of the country.

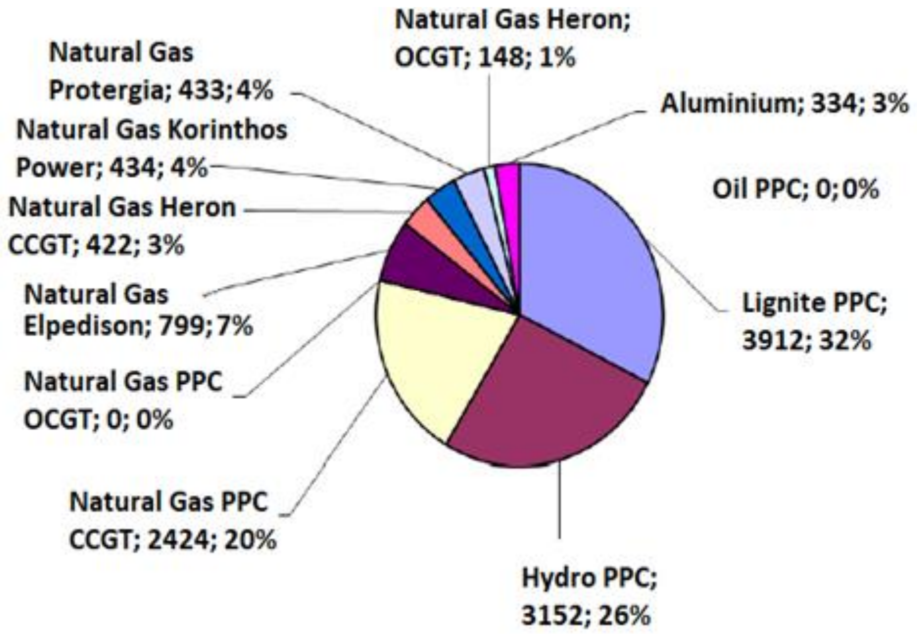


Figure 12: Installed Electricity Generation (net) Capacity in 2017 (MW) per producer and fuel (%) excluding IPPs' RES

In terms of volume, the incumbent's share in 2017 in the interconnected system amounted to almost 78% of the domestic production (excluding RES), while independent gas producers achieved a 22% share. The net installed capacity and the produced volumes per fuel and producer in 2017 are depicted in the following Figures 6, 7 and 8.

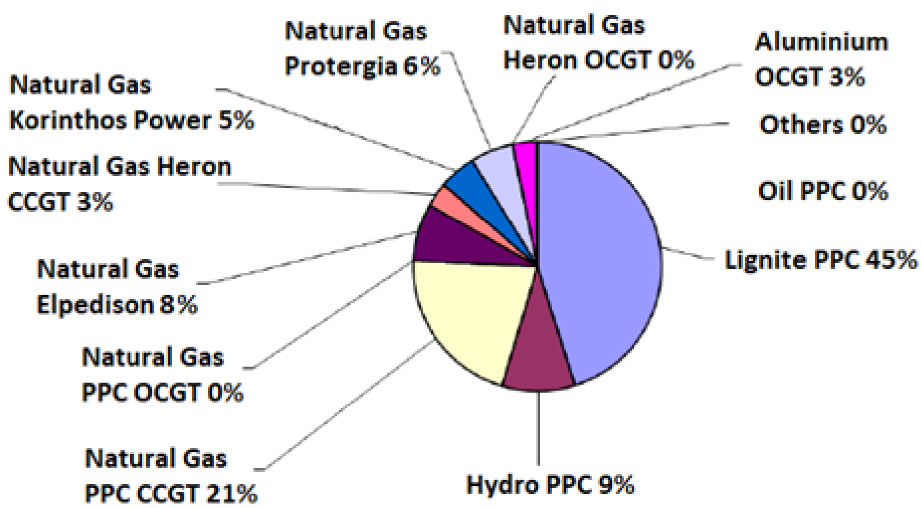


Figure 13: Electricity Generation in 2017 per producer and fuel (%) excluding IPPs

The HHI index for the wholesale market in 2017, a measure of market concentration, attained the value of 5,982 in terms of volume production and 6,357 in terms of installed capacity; these values are to be compared with 7,820 and 6,804, respectively, in 2014. We should underline however; the calculation of these indicators does not consider RES generation and RES installed capacity. The main argument is that RES do not participate in the market under the implemented rules of feed in tariff (FiT) and of access (dispatch) priority, in 2016. Market concentration is decreasing further if we consider the net imports volume, in 2016.

Table 21: Share in produced volume per Group in 2017 (%)*	
PPC	77%
Elpedison	7%
prot+aloum+kp	12%
Heron	4%
Note: * RES generation from the Independent power generators is not included	
Year	**HHI index (production)**
2017	**5,982**
2016	5,999
2015	7,820
2014	8,091

Table 22: Share in installed capacity (MW) by Group (%) in 2017	
PPC	80%
Elpedison	6%
prot+aloum+kp	10%
Heron	4%

Table 23 Market Share Installed Capacity & HHI Index, 2017	
2017	**PPC**
PPC’s Share in installed generation capacity (except RES)	79.1%
PPC’s Share in installed generation capacity (incl.RES)	56.7%
Year	**HHI index installed capacity**
2017	**6,357**
2016	6,423
2015	6,804
2014	6,624

3.2.1.7. Price Monitoring

The current market design involves two distinct settlement processes:

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

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

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

The System Marginal Price (SMP) is the price at which the electricity market is cleared, that is, the price that all those who inject energy into System, is totally paid by all those who request energy from the System. In particular, the Marginal Price of the System is shaped by the combination of price offers and submitted quantities each day by the available units of electricity generation, and the hourly demand for electricity, formed on a daily basis by consumers.

For the sake of protecting consumers and shaping healthy conditions competition, an administrative ceiling price is set on what is offered by the available units, which is currently 300 €/MWh, as well as the lowest bidding level, which is equal to the variable cost of each unit, so as producers to be paid at least the cost of their fuel and to prevent unfair practices by the dominant company. Within the framework of RAE's overall plan for wholesale market reorganization, the Authority re-evaluated the design and the operation of the wholesale electricity market mechanisms in order to fix distortions and significantly promote savings (both economic and energy) in electricity generation sector, as well as at the level of the national economy in general. For this reason, RAE, in the course of 2017, took additional regulatory measures.

The average system marginal price (SMP) in 2017 amounted at 54.68 €/MWh, recording an increase (27.6%), compared to the previous year (42.85%) €/MWh), mainly due to the increase in demand and the consequent increase of domestic production, mostly from conventional production units. It is worth clarifying that in 2017 the SMP is subject to further correction, reflecting its most realistic link with the variable cost of the units which is part of the DAS, as since October 2016 came into force the determining of the minimum variable cost methodology of the hydroelectric units (in addition to their mandatory injections).

The Imbalance Marginal Price (IMP) is a more realistic depiction of production cost compared to the SMP as it results from its resolution DAB by entering the real availability of units and measurements (versus forecasts) of quantities such as cargo, RES injections and cross-border flows. In 2017, the average IMP stood at 58.25 €/MWh, +27.7% compared to 2016. To a large extent, IMP was applied to negative deficiencies (deficit) of lignite units that were offset by positive deviations of hydroelectric units and natural gas units.

Volatility between the two prices; SMP and the diverted Marginal Price OTA fluctuated significantly in 2017. Focusing on monthly fluctuations, it is noteworthy that the average SMP has shown quite uneven behavior in 2017, ranging between 44.57 €/MWh in April and 74.60 €/MWh in January. The maximum monthly level of the SMP in January resulted due to the crisis in the country's natural gas supply mechanism, combined with technical characteristics and limitations, its existing model of energy co-optimization and the opportunity for profit presented to the participants (traders) through strategic energy injection bids in DAS. In general, the change in SMP compared to 2016 levels varies on a monthly basis between 10% and 63%, with a significant fact that from February until April the downward trend in SMP prices was noticeable (with less -4% change in April and -25% in February), expressing the reduction in consumption due to the improved, in relation to the January, temperatures prevailing, as well as falling prices heating oil combined with the operation of gas plants, the fuel of which has a constant and lower price.

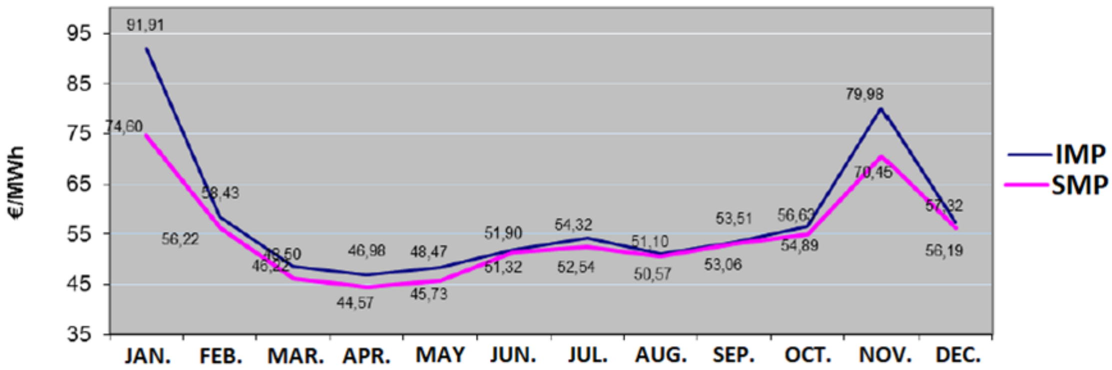


Figure 14: Imbalance Prices IMP (OTA) and SMP (ΟΤΣ) Variation

At the cash-flow level, the revenues of conventional technology producers (excluding RES) resulting from the resolution of the DAS, amounted to € 2.1 billion in 2017, showing a very large increase compared to 2016, during the year whose equivalent was € 1.46 billion. In 2017, the revenue resulting from the solution of the DAS increased for both PPC and their customers Independent Producers. The ex-post clearances carried out by the TSO (ADMIE) amounted to € 0.11 billion compared to € 0.23 billion in 2016. That is, its total value wholesale market in 2017 stood at € 2.22 billion.

Focusing on monthly fluctuations, it is noteworthy that the average SMP showed a great fluctuation in 2017 ranging between 44.57 € / MWh in April and 74.60 € / MWh in December.

Monthly fluctuations of the SMP reflect to a significant extent seasonality demand and individual factors. It should be noted at this point that variation in RES production had an effect similar to that of 2016, as their total annual participation in the DAS increased slightly +4.20%, reaching 20%. It is therefore considered fairly smooth compared to 2013, a year in which, due to State's legislation, RES have risen sharply, doubling their participation in the DAS. The downward trend followed in February until April 2017, when the lowest monthly level was recorded of the SMP at a price that reached 44.57 €/MWh, was suspended in May, where followed up until October in a relatively smooth fluctuation of prices (on average of € 51.35/MWh for these 6 months). Then, in November, a rise appeared to the SMP, which has exceeded marginally the level of 70 €/MWh, and this mainly due to the increase of the load combined with its failure to cover from RES, Hydro, imports and lignite units. Finally, in December the prices returned to October levels (average OTS at € 56.19 / MWh) due to consumption reduction, as temperatures were mild for the season.

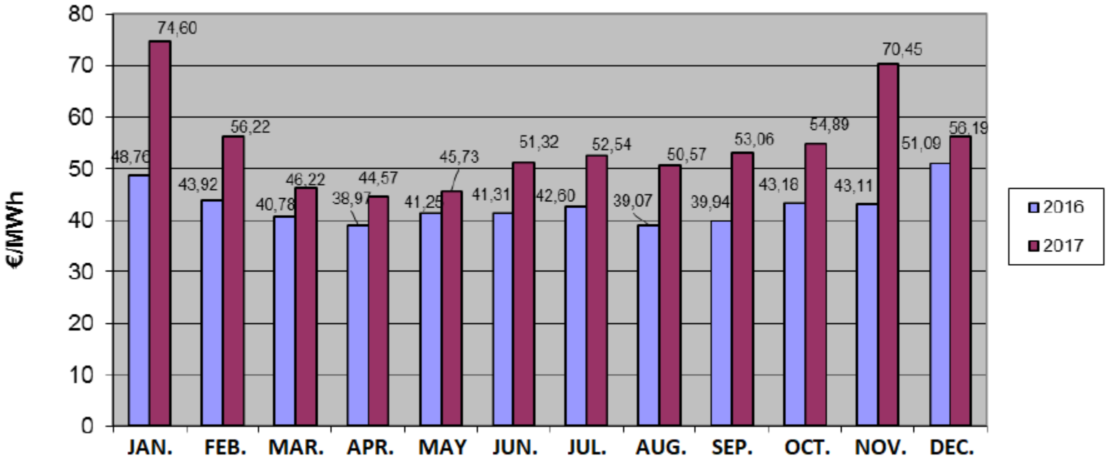


Figure 15: SMP Monthly Average (2016-2017)

The following figure depicts the rolling average of monthly SMP, calculated on a daily basis as well as for intraday intervals, and in particular: (a) for the first eight (8) hours of distribution (0:00-8:00, non-peak) and b) for the following distribution hours (8:00-24:00, peak).

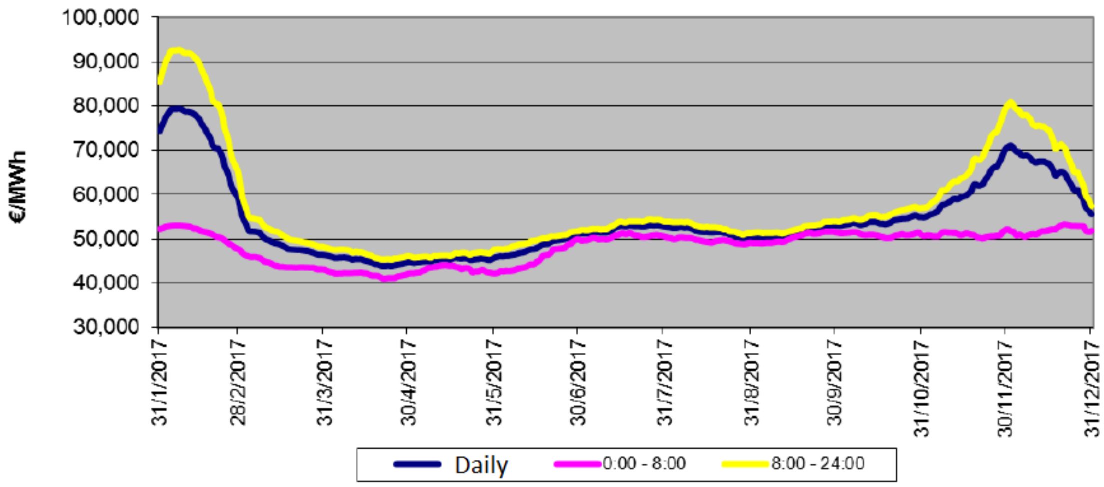


Figure 16: SMP Daily moving Average

It is noteworthy that the frequency of zero values decreased in 2017 to 8 hours comparing to 10 hours in 2016, 5 hours in 2015, 31 hours in 2014 and 674 hours in 2013. Note that zeros occur predominantly at the times demand, in which compulsory injections (hydropower, renewable energy production, technical minimum thermal units, imports) exceed consumption. In these cases, is cut in imports, due to the structure of the DAS solving constraints, and, therefore, the SMP is determined by input supply, which had been zero-rated. Limiting zero values partly reflecting a marked decline in domestic production, resulting in the technical minimum of conventional units to enter and cut imports to a lesser extent. 88% of these zero values corresponding to 7.04 hours of distribution were observed in the months of May and October, and whenever there were particularly high imports in the order of 795.2 to 1,643.00 MWh, covering up to one third of demand for those hours (namely coverage ranged from 18.20% to 32.32% for free). Taking account of the technical requirements of the algorithm, such as function modules to provide redundancy, inability quenching units before the expiration of the minimum running time, etc., the fact that there were no heavy rains and therefore mandatory injections hydropower for specific times, probably contributed to reducing the phenomenon.

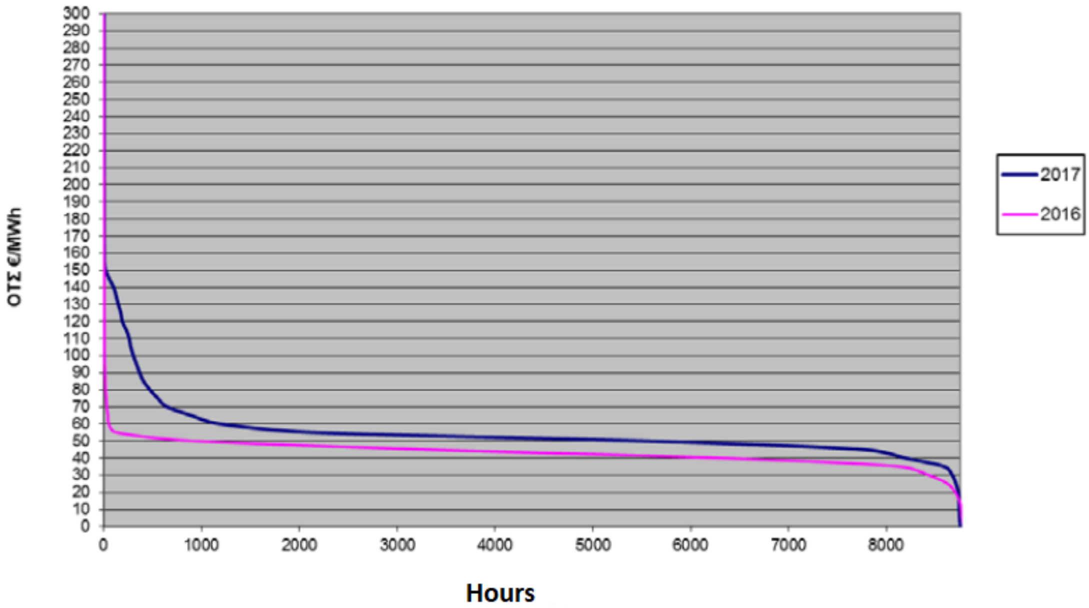


Figure 17: SMP Duration Curve (ΟΤΣ)

The volatility of the hourly levels of the SMP, as reflected in their standard variation, showed a significant increase, marking an average daily price based on 7.83 €/MWh in 2017, compared with 4.63 €/MWh in the year 2016 and directly compared to the volatility level of 2015 at 7.28 €/MWh. This development reflects the less homogeneous fluctuation of the three prices in terms of which were formed in 2016. These features are reflected in the SMP curve.

In particular, during November, very high volatility was observed fluctuation of the hourly values of the SMP compared to the respective values of last months. In particular, during this period the injecting offers of thermal units with natural gas fuel were increased, either for the purpose of strategic reasons. The minimal supply prices of the Hydro units, taking into account the method of minimal variable costs calculation and due to the low level of water supplies in their reservoirs, reached significantly higher levels. Further, due to planned maintenance, there were lignite units and natural gas units, which had been shut down. Finally, because of the shutdown of Greece-Italy electrical interconnection from 09.10.2017 and the high energy demand in the countries of Europe, a decline in imports was observed.

It is indicative that the SMP exceeded for several hours 80 €/MWh (5.3% of hours' distribution) compared to 0.2% of the hours in 2016 and 1% of the hours in in 2015. However, these 463 hours are mainly limited to 2 months when high prices appeared: 203 hours were in January (period of crisis in gas market) and 196 hours in November. In general, the SMP was mainly determined from gas units (39%) and then from lignite units (36% of the total hours of the year), while at a lower frequency concerning imports (11%), exports (8%) or hydroelectric units (6%).

With regard to extreme hourly values, the SMP did not reach the ceiling of 300 €/MWh while it exceeded 150 €/MWh in just 15 hours of allocation, mainly within January, as there were extreme conditions that marked a deficit due to the crisis in the country's natural gas supply mechanism. Especially for the day of distribution 24.01.2017 in which the highest price occurred of the SMP (200 €/MWh), there were several technical reasons happening simultaneously: high demand, limited production from RES, annual maintenance of the lignite unit Ag. Dimitrios 1, damages of three lignite units (Ag. Dimitrios 4 and 5, Heart 4) and two gas units (Lavrio 5 and Thisvi), bad lignite quality almost at all lignite units, imposing energy constraints on Hydro units by 10.01.2017, reduced imports and marginal fulfillment of the Tertiary Reserve Claim. The simultaneous coexistence of the above conditions in combination with the existing model of energy and reserve co-optimization and with profit opportunity presented to Producers and Energy Merchants due to of the limited supply justifies this significant increase in the SMP.

3.2.1.8. Monitoring of transparency

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

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

3.2.1.9. REMIT (EU Regulation 1227/2011)

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

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

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

The reporting of market participants' transactions take place through the Registered Reporting Mechanisms (RRM) which have been certified by RAE.

3.2.1.10. Monitoring of effectiveness of market opening and competition

The challenging issues that continued to arise in the domestic electricity market throughout 2017 emphasized that, apart from plant portfolio diversification, a crucial element for a more competitive market evolution, with self-sustained financial outcomes and less dependency on supplementary mechanisms, would be the emergence of open market-oriented reforms.

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

Nominated Electricity Market Operator (NEMO): According to the provisions of Commission Regulation EU 2015/1222, 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 is a monopoly and can be only one entity that is responsible for the day-ahead electricity market and the intraday market, which is the Market Operator (LAGIE). Therefore, with the 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.

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

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 1,200 MW of baseload lignite and hydro generation. The auctions are organized on an annual and quarterly basis for each year, for 4 years (2016-2020). The proposed auctions are transitional and designed so that by the time the EU Target Model is 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.

Following negotiations between the Greek authorities and the European Commission, there was an agreement on the adoption of the NOME Auction System, which was introduced in the legal order with Law 4389/2016 "Establishment of an electricity sale mechanism by PPC S.A., through auctions of future electricity products with physical delivery - repeal of the provisions of Law 4273/2014 on the creation of a new vertically integrated electricity company - arrangements for full ownership unbundling of ADMIE from PPC S.A., pursuant to Directive 2009/72/EC, by maintaining public control - arrangements for introducing a transitional flexibility mechanism".

Pursuant to article 135 of Law 4389/2016 "*A mechanism is established for the sale of electricity by the public limited company PPC S.A., pursuant to natural gas future products through natural gas Daily Energy Planning and with a regulated value starting point to Eligible Suppliers of Electricity. Purpose of the mechanism is the redistribution of shares in the retail electricity market in the interconnected system of PPC's shares and alternative suppliers, from the percentage held in August 2015 by PPC S.A., at less than 50%, up to the year 2019*".

Subsequent to the entry into force of Law 4389/2016, Decisions no. 35/2016 and 38/2016 of the Government's Economic Policy Council on the "Approval of auction application plan (NOME)" were taken.

Following the completion of the primary and secondary legislative framework for the sale of electricity through auctioning future products, RAE, in 2017, issued a series of regulatory decisions on the gradual development of the relevant mechanism and its adaptation to requirements of the domestic electricity market.

For the first Auction of 2017, RAE published Decision 21/2017 (Government Gazette B '271 / 31.01.2017) for the "Approval of the Technical Characteristics and Auction Terms of Forward Electricity Products to be auctioned on January 31, 2017, in accordance with paragraph 1, (d) of article 138 of Law 4389/2016 (Government Gazette A 94 / 27.05.2016), as in force, and article 16 of the Exchange Code for Electricity Forward Auctions (Government Gazette B3164 / 30.09.2016)". The auction took place on 07.02.2018.

Following the first auction results, RAE put forward the proposal submitted by the Market Operator (LAGIE) in a public consultation and after processing it, RAE published Decision No 184/2017 (Government Gazette B '1069 / 29.03.2017) on the "Amendment of Article 41 of the Exchange Code for Electricity Forward Auctions (Government Gazette B 3164 / 30.09.2016) as in force".

For the second scheduled auction for the year 2017, RAE published Decision no. 298/2017 (Government Gazette B '1338 / 20.04.2017) for the Approval of the Technical Characteristics and Auction Terms of the Forward Electricity Products to be auctioned on April 26, 2017, in accordance with paragraph 1, (d) of article 138 of Law 4389/2016 (Government Gazette A 94 / 27.05.2016) and the article 16 of the Exchange Code for Electricity Forward Auctions Products (Government Gazette B3164 / 30.09.2016) ". The auction took place on 26.04.2017.

After RAE's first opinion, for the determination of the methodology and the calculation of the reserve price of forward electricity products; RAE issued its yearly revised opinion No 8/2017 on the new Reserve Price of forward electricity products, according to the provisions of article 139 par. 1 of Law 4389/2016 (Government Gazette A 94 / 27.05.2016) as in force".

For the third scheduled auction for the year 2017, RAE published Decision no. 571/2017 (Government Gazette B 2467 / 19.07.2017) for the "Approval of the Technical Characteristics and Auction Terms of the Forward Electricity Products to be auctioned on July 19, 2017, in accordance with paragraph 1, (d) of article 138 of Law 4389/2016 (Government Gazette A 94 / 27.05.2016) and the article 16 of the Exchange Code for Electricity Forward Auctions (Government Gazette B3164 / 30.09.2016) ". The auction took place on 19.07.2017.

Following a proposal by the Market Operator (LAGIE) regarding the readjustment of forward products’ annual quantity to be auctioned in 2017, RAE put the proposal under public consultation and proceeded to publish Decision no. 817/2017 (Government Gazette B '3577 / 11.10.2017) on the Adjustment of the annual quantity of electricity, available through auctions of forward electricity products with physical delivery, the cascading of the energy quantity to individual forward products and the schedule of auctions for the year 2017, in accordance with Articles 135 (4) and 138 (1) of Law 4389/2016, as in force".

At the same time, RAE issued the Decision No. 849/2017 (Government Gazette B '3658 / 17.10.2017) on "Administratively Defined Prices” under the provisions of paragraph 2 of article 17 of the Exchange Code for Electricity Forward Auctions (Government Gazette B3164 / 30.09.2016), as in force ".

For the fourth and last scheduled auction for the year 2017, RAE issued Decision No. 870/2017 (Government Gazette B '3728 / 23.10.2017) "Adoption of the Technical Characteristics and Auction Terms of Forward Electricity Products to be auctioned on October 25, 2017, according to paragraph 1 (d) of article 138 of Law 4389/2016 (Government Gazette A 94 / 27.05.2016) as in force and Article 16 of the Exchange Code for Electricity Forward Auctions (Government Gazette B3164 / 30.09.2016) ". The auction took place on 25.10.2017.

In view of planning the auctions for the year 2018, RAE after the relevant submission of the proposal by the Market Operator (LAGIE), issued Decision no. 1091/2017 (Government Gazette B '4831 / 29.12.2017) on Determination of annual electricity quantity, available through auctions of forward electricity products with physical delivery, the cascading of the energy quantity to individual forward products and the schedule of auctions for the year 2018, in accordance with article 138 par. 1 of Law 4389/2016, as in force. RAE also issued Decision no. 1097/2017 (Government Gazette B '4831 / 29.12.2017) for the "Approval of the Charges relating to the recovery of the cost of conducting the Auctions of Forward Electricity Products for the year 2018, in accordance with paragraph 1 of the Article 140 of Law 4389/2016 (Government Gazette A 94 / 27.05.2016) as in force and Article 10 of the Exchange Code for Electricity Forward Auctions (GG B3164 / 30.09.2016), as amended and in force".

3.2.2. Retail Market

3.2.2.1. Description of the retail market

Electricity consumption in 2017 in the country's Interconnected Network showed a slight increase compared to 2016 levels, according to the accounts of the System Operator on the MV and the LV and the Monthly Energy Schedule December 2017 of the Transmission System Operator for HV (46,876 GWh in 2017 compared to 45,923 GWh in 2016, a small increase approximately 2%). This increase is reversing a long period of significant decline of consumption, as shown in the Table below, which was clearly correlated with the prolonged economic downturn experienced by the country. It is indicative that overall in the period from 2013 to 2016, the evolution of electricity demand in the Interconnected System moves steadily to negative levels, while in 2017 it seemed to recover marginally.

Table 24: Electricity consumption at the interconnected system (GWh)						
	Year	Large Industrial Customers	Household Customers	Small Industrial & Commercial Customers)	Other (e.g. agriculture, public, traction)	TOTAL (GWh))
LV	2012	-	16,714	10,123	3,734	**30,571**
	2013	-	15,973	9,560	3,640	**29,173**
	2014	-	15,569	9,523	3,735	**28,827**
	2015*	-	15,817	9,245	3,277	**28,339**
	2016	-	15,048	9,192	3,385	**27,625**
	2017	-	15,651	9,344	3,285	**28,280**
MV	2012	-	-	8,471	1,513	**9,984**
	2013	-	-	8,904	1,487	**10,391**
	2014	-	-	8,179	1,477	**9,656**
	2015*	-	-	8,351	1,473	**9,824**
	2016	-	-	8,643	1,478	**10,121**
	2017	-	-	8,764	1,536	**10,300**
HV	2012	6,507	-	-	1,361	**7,868**
	2013	6,599	-	-	1,168	**7,767**
	2014	6,702	-	-	1,314	**8,016**
	2015	6,805	-	-	1,150	**7,955**
	2016	7,062	-	-	1,115	**8,177**
	2017	7,268	-	-	1,028	**8,296**
Total	2012	6,507	16,714	18,594	6,608	**48,423**
	2013	6,599	15,973	18,464	6,295	**47,331**
	2014	6,702	15,569	17,702	6,526	**46,499**
	2015	6,805	15,817	17,596	6,526	**46,118**
	2016*	7,062	15,048	17,835	5,978	**45,923**
	2017	7,268	15,651	18,108	5,849	**46,876**

As in 2016, the year in which the electricity supply activity has shown an upward trend, so in 2017 it continued and strengthened competition in the supply activity. Within 2017, five companies which have obtained licenses to supply electricity, «ECONOMIC GROWTH S.A.», «KEN S.A.», «VOLTON S.A.», «EPA THESSALONIKIS - THESSALIAS S.A. "and" EPA ATTIKIS S.A. ", actively entered in the supply of electricity market, as proven by the review data of the System Operator. At the end of 2017, ten (19) 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. NOVAERA ENERGY S.A.
10. GREEK POST OFFICES S.A.
11. ECONOMIC GROWTH S.A.
12. VI.ENER. S.A.
13. INTERBETON S.A.
14. OTE REAL ESTATE S.A.
15. GREENSTEEL CEDALION COMMODITIES S.A.
16. KEN S.A.
17. VOLTON S.A.
18. EPA THESSALONIKIS-THESSALIAS S.A.
19. EPA ATTIKIS S.A.

PPC remained the main supplier throughout retail representing 95.30% of the total number of customers at the end of 2017 and 83.66% of total sales in LV and MT. With regard to switching between suppliers, just 2.81% (in cash) of the total of Low and Medium Voltage customers changed supplier within 2017, according to the DSO (DEDDIE) report, representing, in terms of consumption levels ratio, 1.91% of total consumption in Low and Average Voltage.

In December 2017, forty-three (43) supply licenses and fifty-six (56) electricity trading licenses were into force:

• RAE issued seven (7) decisions for license granting, one (1) decision to amend a supply license, two (2) decisions to amend permits for supply selling (1) a decision to renew a selling permission, and one (1) a decision to suspend a marketing permission.

• Four (4) requests for amendment of selling and supply licenses are pending for final decision.

• RAE filed two (2) new applications for electricity supply licenses which are pending for evaluation and final decision.

• An application for amending a selling permission is pending for the final decision which has not provided the necessary additional information.

• Three (3) selling permission applications are pending from previous years; for one of which a later suspension request was submitted and it is pending for evaluation and final decision.

3.2.2.1. Competition and market shares

Table 25: Suppliers' Retail Market shares by customers' category	Number of customers	PPC	WATT & VOLT	GREEN	NRG	ELPEDISON	NOVAERA	VOLTERRA	OTE ESTATE	PROTERGIA	ECONOMIC GROWTH	HPΩN	Greek Post Offices S. A	VOLTON	KEN	EPA TH/TH
Household customers	5,175,935	4,966,574	25,748	5,914	2,968	52,263	6	6,670	1	66,248	112	35,928	3,160	4,456	5,818	68
Small industrial and Commercial LV customers	1,140,094	1,040,830	20,176	4,799	3,649	23,300	5	3,716	8,766	14,891	74	14,314	1,112	901	3,541	10
Other LV customers	304,673	304,183	4	2	4	43	0	137	1	8	0	271	8	1	11	0
Total LV customers	**6,620,702**	**6,311,587**	**45,928**	**10,715**	**6,621**	**75,606**	**11**	**10,523**	**8,768**	**81,147**	**186**	**50,513**	**4,280**	**5,358**	**9,370**	**78**
Commercial and Industrial MV customers	8,657	5,898	163	94	209	548	11	154	0	646	10	817	42	7	27	1
Other MV Customers	1,674	1,638	0	0	0	7	0	7	0	3	0	18	1	0	0	0
Total number of MV customers	**10,331**	**7,536**	**163**	**94**	**209**	**555**	**11**	**161**	**0**	**649**	**10**	**835**	**43**	**7**	**27**	**1**
Total number	**6,631,033**	**6,319,123**	**46,091**	**10,809**	**6,830**	**76,161**	**22**	**10,684**	**8,768**	**81,796**	**196**	**51,348**	**4,323**	**5,365**	**9,397**	**79**
Market share (%)		**95.30%**	**0.70%**	**0.16%**	**0.10%**	**1.15%**	**0.00%**	**0.16%**	**0.13%**	**1.23%**	**0.00%**	**0.77%**	**0.07%**	**0.08%**	**0.14%**	**0.00%**

Table 26: Consumption by consumers' category	Consumption (MWh)	PPC	WATT & VOLT	GREEN	NRG	ELPEDISON	NOVAERA	VOLTERRA	OTE ESTATE	PROTERGIA	ECONOMIC GROWTH	HERON	Greek Post Offices S.A.	VOLTON	KEN	EPA TH/TH
Household customers	15,650,510	15,066,764	77,399	15,088	7,733	192,517	127	10,989	0	195,906	292	73,765	2,800	3,624	3,503	0
Small Industrial and LV customers	9,344,018	7,288,720	331,880	119,477	120,765	462,787	92	84,093	92,739	424,261	1,748	381,994	17,517	5,144	12,423	12
Other LV customers	3,284,753	3,275,198	30	134	129	901	0	3,117	3	280	0	4,727	11	200	23	0
Total number of LV customers	**28,279,282**	**25,630,682**	**409,309**	**134,700**	**128,627**	**656,205**	**220**	**98,199**	**92,742**	**620,447**	**2,040**	**460,486**	**20,329**	**8,968**	**15,949**	**12**
Commercial and Industrial MV customers	8,763,548	5,192,277	90,498	82,708	274,471	796,667	11,444	219,494	0	943,811	8,458	1,055,686	24,035	2,390	18,377	260
Other MV customers	1,536,316	1,452,742	0	93	0	21,411	0	23,205	0	1,282	0	37,548	35	0	0	0
Total MV customers	**10,299,864**	**6,645,020**	**90,498**	**82,801**	**274,471**	**818,077**	**11,444**	**242,698**	**0**	**945,093**	**8,458**	**1,093,234**	**24,070**	**2,390**	**18,377**	**260**
Total number of customers' consumption	**38,579,146**	**32,275,701**	**499,807**	**217,501**	**403,098**	**1,474,282**	**11,664**	**340,897**	**92,742**	**1,565,540**	**10,498**	**1,553,720**	**44,399**	**11,358**	**34,326**	**273**
Market share (%)		**83.66%**	**1.30%**	**0.56%**	**1.04%**	**3.82%**	**0.03%**	**0.88%**	**0.24%**	**4.06%**	**0.03%**	**4.03%**	**0.12%**	**0.03%**	**0.09%**	**0.00%**

3.2.2.2. Supplier Switching

Although the figures on customer switching seem small at an overall level, though at the level of voltage and among consumers categories, there have been areas where there has been a remarkable increase especially when comparing current data with those of 2016 (indicatively the categories of small and medium-sized professional clients use). This trend is normal as the implementation of the Mechanism for Electricity Sale through auctions continued in 2017, a structural measure that aims by definition, at increasing competition in the retail electricity market and at impairing the share of PPC S.A. in the supply of electricity based on statutory objectives. The following table includes a comparative depicting of customer switching for the time periods 2016-2017:

Table 27*: Switching number of LV and MV customers in the interconnected system 2016-2017 (estimated numbers), source DEDDIE S.A)*	Number of Customers in the interconnected system 2017	Total Consumption 2017 (MWh)	Switching number of customers in 2017	Switching rates % in total no of customers in 2017	Switching rates % in total no of customers in 2016 (%)	Consumption of the switching number of customers 2017 (MWh)	2017 (%)	2016 (%)
Household customers	5,175,935	15,650,510	135,536	2.62%	1.35%	201,821	1.29%	0.68%
Small industrial and LV Customers	1,140,094	9,344,018	49,606	4.35%	2.99%	274,663	2.94%	2.98%
Oher LV customers	304,673	3,284,753	503	0.17%	0.00%	3,693	0.11%	0.00%
Total LV customers	6,620,702	28,279,282	185,645	2.80%	1.57%	480,178	1.70%	1.36%
Commercial and Industrial MV customers	8,657	8,763,548	764	8.83%	14.48%	223,180	2.55%	5.34%
Other MV customers	1,674	1,536,316	37	2.21%	0.06%	34,006	2.21%	0.01%
Total MV customers	10,331	10,299,864	801	7.75%	12.15%	257,186	2.50%	4.57%
Total no of LV and MV customers	6,631,033	38,579,146	186,446	2.81%	1.58%	737,363	1.91%	2.22%

3.2.2.3. Financial Liquidity in the Electricity Retail Market

By 2017, the market situation was extremely critical, above all due to the decrease in liquidity, the continued existence of PPC's bad debts and the generally difficult economic environment. More specifically, there was a high level of business and credit standing risk and continuing of the significant cash-flow problems throughout the market trading chain. For 2017, the relatively high debts of PPC's customers were maintained based on the announcements of the company that for 2017, its unsecured debts exceeded 2 billion euros. This development was due to consumers' limited financial capacity to regulate their debts. In addition, it should be added the extremely difficult position in which the financial sector was particularly with the enforcement of Capital Controls resulting in further tightening of credit ratings which led to a dramatic reduction in the number of grants credits, increased borrowing costs for the participants, the difficulty in managing business and credit risk as well as an increase in working capital.

The consequences of the non-existence of a Covering Body and Clearance Body, like Codes prescribe, are now obvious and pose serious problems at the proper functioning of the market. In the context of the pan-European implementation of Target Model, and after intense pressure exerted from RAE in the last few years, even in 2018, is planned the establishment of a Clearing Institution in the Greek market, which will contribute significantly to improve liquidity. During the transition period, due to credit risk, the secure handling of transactions is often difficult for the Operators (LAGIE, ADMIE, DEDDIE), despite important decisions taken by the Authority to limit their financial risk.

Finally, in the context of the information on the progress of overdue debts of Participants towards Operators, RAE receives from the Operators information about the course of those debts and the corresponding actions of the Operators in order to achieve, as much as possible, a clear picture of transactions' cash chain between Operators, Producers, Suppliers and Merchants. RAE throughout the year systematically monitored the course of financial transactions and, in particular, the long-term formation of debts of participants, and recognized the need for further examination and for that reason proceeded to more detailed investigation by publishing Decisions 571A and 571B in December 2016. In the hearings PPC were called in its capacity as Supplier and as Producer, with the purpose of managing its debts towards Power Operators and DEDDIE in its capacity as Distributor Network Operator and as Non - Interconnected Islands Operator, concerning the tracking and managing the transactions it performs within its responsibilities. The relevant decisions by RAE are expected in 2018.

3.2.2.4. Price monitoring

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

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

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

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

Price-comparison tool

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

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

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.

As for the monthly average market price shaped by the performance of Suppliers in the wholesale market of the Interconnected System and is taken into account in the calculation of the NII Social Utilities' Services Tariff_, based on of the relevant provisions of the NNIs Methodology, the ADMIE S.A. submitted to RAE the updated monthly data for the years 2014 and 2015. According to the relevant documents, the definitive procedure has not been completed for the identification of a market average price that was formed by the performance of Suppliers in the wholesale market of the Interconnected System for the year

2016, because, the definitive determination concerning the component of the RES levy for the period October-December 2016 is pending between the competent Operators. For this reason, the temporary monthly average prices of the market were used for determination of the NII Services of General Interest Tariff for the relevant year, up to the final update of monthly data of the Suppliers charge (ΠΦΕΧΕΛ) component at the average market price that has been shaped by the performance of Suppliers in the wholesale market in the Interconnected System, by its responsible Operator ADMIE S.A. system, where the final calculation of the NII Services of General Interest Tariff will be made PSO_NIIs.

Based on all of the above, and by applying thorough audits during implementation of the relevant PSO_NIIs methodology, the temporary monthly NII Services of General Interest Tariff was calculated for the years 2014, 2015 and 2016, per NII System, which were approved by RAE's Decision 688/2017. For these NII Social Utilities' Services Tariffs a Decision by the Authority will follow for the final clearance of accounts as set above.

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.

3.2.3. Non-interconnected islands (NII)

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

In February 2014, RAE adopted the Operation Code for Non-Interconnected Islands (NII Code, Decision 39/2014, National Gazette B '304 / 02.11.2014), which largely completed the secondary legislation that regulates the operation and the transactions at the NII electrical systems, as provided for by Law 4001 / 2011. Therefore, with the NII Code in effect, the NII markets may be open to competition, for both the production and the supply activities. In addition, on August 14, 2014, the European Commission granted to Greece (Decision 2014/536/EC) derogation from the provisions of Chapters III and VIII of Directive 2009/72/EC for the NIIs. This Decision followed the relevant applications of the Greek State in December of 2003, based on article 26 of Directive 2004/54/EC, and then in January of 2012, based on article 44 of Directive 2009/72/EC. Per the Commission's above Decision:

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

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

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

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

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

For this reason, RAE adopted 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.

The state of electrification of the Non-Interconnected Islands (NNL) of our country, in 2017, has not changed substantially in relation to the beginning of the decade. NIIs continue to be electrified by local power stations of PPC S.A., which operate on fuel oil, heavy (heavy fuel oil) or light (diesel). The contribution of RES, especially wind and photovoltaics, is also important for the stations operating on these islands.

However, in 2017 RAE issued Recommendation 14/2017 to the Ministry of Energy for the issuance of a Decree regarding the Power Purchase Agreement of Ikaria Hybrid Power Plant.

3.3. Security of supply

According to article 12, Law 4001, the RAE shall monitor the security of energy supply, especially with regard to the balance between supply and demand on the Greek energy market, anticipated future demand, anticipated additional electricity and natural gas production, transmission and distribution potential already programmed or under construction, the standard and level of maintenance and reliability of transmission systems and distribution systems and the application of measures to cover peak demand and conditions on the energy market in terms of the facility to develop new production potential.

3.3.1. Monitoring the balance of supply and demand – interconnected system

Electricity demand and electricity demand peak

Table 27 presents the evolution of annual electricity consumption in the interconnected system, since 2008, as reported by the TSO, ADMIE S.A. In 2017, the amount of electricity demand reached 51,93 TWh which is an increase of 1,41% comparing to 2016 demand.

Table 28: Energy and peak electricity demand in the interconnected system, the 10 years period 2007-2017.										
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Total electricity consumption excluding pump storage (GWh)	56.310	53.490	53.545	52.915	52.611	50.664	50.228	51.355	51.212	51.932
Peak load (MW)	10.217	9.809	9.872	10.105	10438	9.161	9.263	9.813	9.207	9.674

Table 28 presents a forecast of the evolution of annual electricity consumption and peak demand in the interconnected system for the period 2018 - 2026, according to the Ten-Year Network Development Plan (TYNDP) of the TSO for the period 2017-2026, which approved by 280/2016 RAE Decision.

Table 29: Energy and peak electricity demand forecast in the interconnected system, for the period 2018-2026.									
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Total electricity consumption excluding pump storage (GWh)	53.690	54.510	55.180	55.720	56.165	55.620	57.070	60.930	61.450
Peak load (MW)	10.130	10.285	10.410	10.515	10.600	10.680	10.770	11.500	11.600

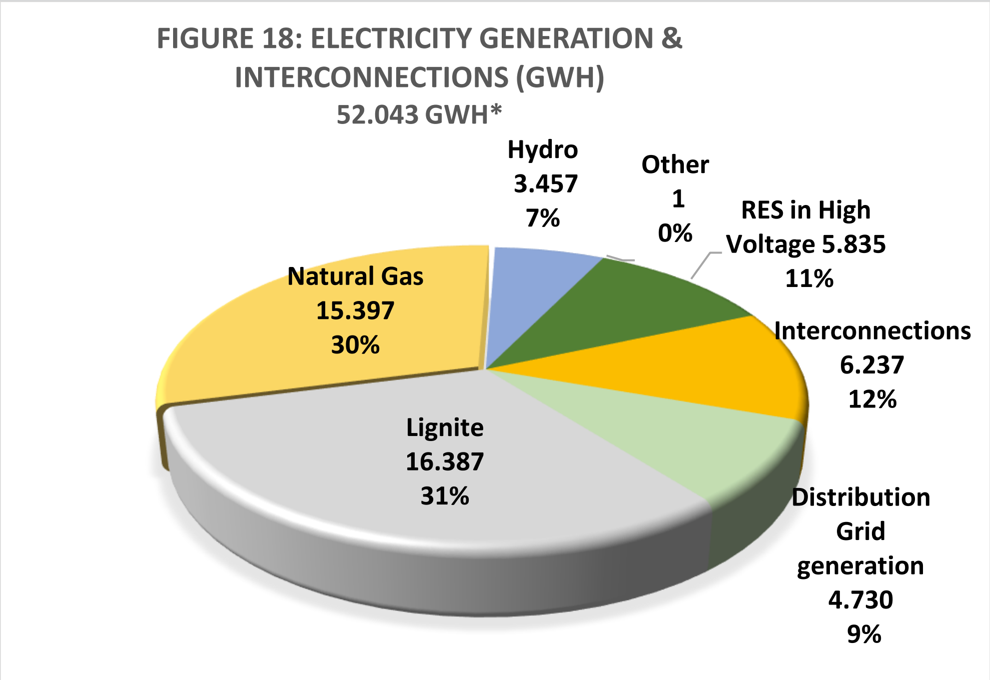
On the demand side, according to the approved by RAE TYNDP, in 2009 Greece has seen a large decline in electricity (industrial) demand compared to 2008, which is due to the relocation of industry and the impact of energy efficiency and the economic recession. From 2010 until 2016, the demand is slightly declining except in 2015, when it increased by 2,2% compared to 2014. In 2017 the total electricity demand increased by 1,4 % compared to 2015. In the coming decade, an increase in electricity-demand is expected of about 1% per year.

The main risk for security of supply is the thermo-sensitivity of the demand and the peak load during cold snaps and heat waves. In winter periods electricity consumption is very sensitive to temperature due to the electrification of heating.

Installed capacity and generation

Installed capacity & generation is presented in section 3.2.1.2.

According to the monthly energy balance reports of ADMIE, the electricity generation mix in 2017 had a diversified structure, as shown in the figure below.



*Including pump storage

Lignite units generated 16.387 GWh, natural gas units generated 15.397 GWh, RES units connected to High Voltage grid generated 5.835 GWh, units connected to Distribution Grid (mainly RES) generated 4.730 GWh, hydro units generated 3.457 GWh and import flows supply almost 6.237 GWh, in 2017.

Greece is currently undertaking significant energy system transformation in order to achieve its long-term goals for decarbonization, energy efficiency and penetration of renewable energy sources. Power system adequacy at periods of peak demand as well as integrating in the system larger shares of intermittent sources of electricity generation (RES) are therefore of key importance in order to ensure energy security.

Generation adequacy assessment

In the context of the current legislation, the Transmission System Operator, ADMIE S.A., submitted in May 2017 to RAE, a Generation Adequacy Report[3] for the period 2017-2027. 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 2017 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

[3] http://www.admie.gr/fileadmin/groups/EDAS_DSS/AnaptixiSistimatos/Meleti_eparkeias_2017_2027.pdf

account the relevant network development plans that are expected to be realized (e.g. the electric connections of the Cyclades islands and the island of Crete with the mainland electricity grid), and b) generation projections, taking into account the decommissioning of old existing plants, new generation plants that are expected to be commissioned, and the expected penetration of RES installations of various technologies. Furthermore, given the economic conditions in Greek power market, scenarios for unit early retirement, as well as delays in the infrastructure projects were also examined.

A probabilistic approach, was 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 LOLE (Loss of Load Expectation) and EUE (Expected Unserved Energy) 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.

Main results of the adequacy study

For the purposes of the Adequacy Study, a baseline scenario for the evolution of the power generation system for the period 2017-2027 is set. This scenario includes the new entries and withdrawals of thermal plants. The adequacy analysis presents the reliability indices for the period 2017 – 2027, considering the assumptions for the basic scenario for the evolution of the generation system and the basic scenario for load forecast (Reference Scenario), for three hydraulic scenarios (dry, normal, wet).

The adequacy analysis of the TSO, assuming a LOLE reliability criterion of 1,25 day in ten years (or 3 hours per year), justifies the following conclusions:

- Considering the Reference Scenario, without interconnections, in most of cases LOLE values over the 2017-2027 period exceed the reliability criterion, and therefore it appears that without the contribution of interconnections the power system is expected not to be able to adequately meet the demand (some cases of high hydraulic scenario are excluded) over the next decade. It should be noted that the Reference Scenario of the adequacy analysis presumes no premature retirement of thermal powerplants takes place. Also, it should not be ignored the fact that the contribution from the interconnections may be quite uncertain during scarcity periods (coincident peaks, cold spells, gas supply crises etc). Due to the above growing uncertainties, import capacity is necessary for Greece to maintain its security of supply.

- The simultaneous withdrawal of the units of Kardia and Amydaio on spring 2020, jeopardize the adequacy of the power system over the next two years 2020-2021 where the LOLE indicator is significantly increasing. Especially under unfavorable conditions (dry hydraulic year) the operation of the power system can be characterized as inadequate, despite the contribution of interconnections.
- The expected entry of new the unit Ptolemaida V in early 2022 seems to compensate for the loss of the units of the Kardia and Amydaio, improving the values of the LOLE indicator.
- The significant increase of the LOLE and EUE values since 2025 is due to integration of all Crete's demand to the mainland power generation system and the withdrawal of Megalopolis III at the end of 2025.
- The assumed hydraulic scenario affects significantly the values of LOLE indicator, especially from 2020 onwards.

In addition to generation adequacy, increasing flexibility is also needed to cope with i) intermittent renewable energies, and ii) rising peak demand, while the real value of flexibility is not yet fully recognized. In May 2017, the TSO conducted a study which evaluates the long – term flexibility adequacy of the Greek power system for the years 2017 – 2027 (hereafter "the flexibility study"). The flexibility study highlighted the system' s needs in flexible capacity, for example the requirement for sufficient (upward and downward) system ramping capability in order to follow the increased net load variations under high penetration levels of variable and uncertain RES generation. According to the results of the flexibility study, maximum flexibility needs for the Greek electricity system are in order of 4-5 GW for the short-term horizon (years 2018-2019) and increase up to 6 GW in the mid-term horizon.

3.3.2. Monitoring investment in generation capacities in relation to security of supply

According to article 94 /Law 4001, the Greek electricity transmission system operator shall operate, exploit, maintain and develop the Greek electricity transmission system, so as to safeguard security of supply in Greece in an adequate, secure, efficient and reliable manner

In this respect, according to the provisions of article 95, ADMIE shall execute generating capacity contracts in the interests of security of supply. The overall capacity of the contracts shall be set following a special study of capacity adequacy and reserve margin adequacy prepared by the Greek electricity transmission system operator, taking account of the ten-year Greek electricity transmission system development program and long-term energy planning in Greece approved by the RAE.

Capacity generation mechanisms for the efficient operation of the market and the strengthening of security of supply that continued in 2017 are presented in section 3.2.1.3.

Furthermore, according to the latest TYNDP for the period 2017-2026, approved by RAE, the completion of the following investments in capacity (see also reference above regarding the baseline scenario for the evolution of the power generation system in the adequacy study) has been considered:

- The new combined cycle power plant of PPC in Megalopoli (Megalopoli V), of 811 MW (in trial operation with reduced power from January 2015).
- The future lignite power station of PPC in Ptolemaida of 660 MW.
- The new hydro power plant of PPC “Ilarionas” of 153 MW (in trial operation from February 2014).

In addition, according to the TYNDP, the following crucial projects related to the security of supply in the electricity system, are going to be completed until 2026:

- Expansion of 400 kV system towards Thrace.
- Expansion of 400 kV system towards Peloponnese (will allow the operation of unit Megalopoli V in full power - 811 MW).
- The completion of the construction of High Voltage Centers that will allow safer and more reliable supply of consumers in the wider areas.
- The completion of interconnections of Cyclades and Crete with the mainland electricity system.

3.3.3. Measures to cover peak demand or shortfalls of suppliers

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

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

In 2017, the Greek TSO (ADMIE), organized 2 auctions of two types of interruptible load services (ILS). ADMIE defined two offered types of interruptible load services, as follows:

Table 30 Types of Interruptible load services (ILS)	Warning time	Maximum time of order	Maximum time per year
Type 1*	2 hours	48 hours	144 hours
Type 2**	5 minutes	1 hour	24 hours

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

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

Following notification to the draft Ministerial Decision of 5.5.2014 which included details of the implementation of the measure of interruptiveness, such as the above-mentioned law, the EU's Directorate-General for Competition with No. C (2014) 7374 final /15.10.2014 Decision on the notified measure of alleged State aid "SA 38711 (2014/N) - Greece, Interrupted Load Service for the electrical system in Greece", approved the measure, concluding that it does not constitute State aid.

In that Decision, the duration of the measure was set at 3 years, i.e. until 15.10.2017 and beneficiaries of this are customers whose premises are connected to HV and MV with intermittent power of at least 5MW, after being recorded in the register interrupted load held by ADMIE. Two different types of interrupted load service ILS1 and ILS2 (depending on time the maximum duration of the order and the maximum total duration per year) were recognized and their price was formed through an auction where beneficiaries with the lowest prices were selected, with their compensation (exclusively for reduction capacity) to be determined on the basis of the marginal price. The maximum quantity tendered by the TSO in each auction capped at 1000MW for each service and the total financial monthly compensation by the participation in the interruptibility scheme could not exeed the limit of 15 €/MWh of electricity consumed by the company beneficiary during the relevant month. Applying this cap was intended to ensure that only consumers that were really consuming energy during a month and thus could actually provide the interruptibility service would be reimbursed. Finally, in the event of failure to provide service, sanctions were provided for that case.

The two auctions (one auction for each type of ILS), were organized by the Greek TSO (ADMIE) and took place in March 2017. The two auctions covered the period from April 1st to June 30th 2017. For every auction, the load capacity asked by the TSO was 500MW. The second two auctions (one auction for every type of ILS) were organized by the Greek TSO (ADMIE) in June. Type 1 auction covered the period from 1st of July to 30th of September. Type 2 auction covered the period from 1st of May to 30th of September. For the type 1 ILS auction, the load capacity asked by the TSO was 580MW and for the type 2 ILS was 900MW.

Table 31: Type 1 of Interruptible load capacity services (ILS 1 services) Auctions in 2017						
Month of Auction	Period of Auctions	Marginal price (€/MW-year)	Number of Participants	Maximum Load Capacity Offered (MW)	Total Interruptible Load capacity asked (MW) by the TSO	Difference between the Load Capacity offered and Load Capacity asked (MW)
March	01.04.2017 - 30.06.2017	50.000	21	639,3	500	139,3
June	01.07.2017 - 30.09.2017	41.200	23	610	580	30

Table 32: Type 2 of Interruptible load capacity services (Type ILS 2 services), auctions in 2017.						
Month of Auction	Auction period	Marginal price (€/MW-year)	Number of Participants	Maximum Load Capacity Offered (MW)	Total Interruptible Load Capacity asked (MW) by the TSO	Difference between the Load Capacity offered and Load Capacity asked (MW)
March 2017	01.04.2017 - 30.06.2017	47.500	20	809	500	309
June 2017	01.07.2017 - 30.09.2017	44.000	28	1090	900	190

3.4. The Non-Interconnected islands system (NIIs)

As far as the non-interconnected (island) system is concerned, there are 32 (currently 29) 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 110 kW), up to several hundreds of megawatts (e.g. Crete, peaking around 712 MW). Currently, the energy demand on these islands is covered primarily by local power stations, consisting of conventional thermal power plants using heavy fuel oil or diesel, while a part of this (up to 16.82%) is covered by RES (wind and photovoltaic plants). The sole producer of electricity from conventional units in these non-interconnected systems is currently PPC, while RES power stations on the islands are predominantly privately owned. In the non-interconnected islands, 32 autonomous power systems currently operate without any wholesale electricity market.

In all these autonomous power systems, the Public Power Corporation (PPC) is the only conventional power producer using oil and heavy diesel as a fuel.

3.4.1. Electricity Supply Structure

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

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

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

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

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

3.4.2. Electricity Generation Capacity and Electricity Demand

The share of RES' generation in the total electricity generation of the 32-autonomous power system was 17,70% in 2017. In Crete, the largest island of the non- interconnected system the share of RES in total generation was 23,25%. The level of demand of the 32 (currently 29) autonomous non-interconnected islands varies significantly;

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

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

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

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

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

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

Table 33: Electricity Generation from Conventional stations and RES stations. Demand and Pick of load during 2017					
Non-interconnected autonomous power systems (islands)	**Generation/oil (MWh)**	**RES Generation* (MWh)**	**% RES Production**	**Demand (MW)**	**Peak (MW)**
St Eustratios	1,095	0	0.00%	1,095	0.340
Agathonisi	727	0	0.00%	727	0.211
Amorgos	10,247	463	4.32%	10,710	3,180
Anafi	1,298	0	0.00%	1,298	0.571
Antikythera	276	0	0.00%	276	0.094
Arkie	375	0	0.00%	375	0.137
Astepalaia	6,455	553	7.90%	7,008	2,300
Gavdos	487	0	0.00%	487	0.122
Donoussa	1,016	0	0.00%	1,016	0.446
Erikoussa	879	0	0.00%	879	0.378
Thira	181,217	457	0.25%	181,674	46,900
Ikaria	25,387	2,660	9.48%	28,047	7,439
Karpathos	33,009	4,309	11.55%	37,319	11,180
Kythnos	9,234	352	3.68%	9,586	3,440
Kos-Kalymnos	332,908	49,167	12.87%	382,075	98,200
Lesbos	252,854	47,006	15.68%	299,860	67,050
Lemnos	50,927	9,484	15.70%	60,411	14,600
Megisti	3,549	0	0.00%	3,549	1,050
Melos	42,140	7,041	14.32%	49,181	13,000
Mykonos	140,408	3,995	2.77%	144,403	43,400
Othonei	645	0	0.00%	645	0.290
Paros	188,386	37,368	16.55%	225,755	70,200
Patmos	15,567	2,871	15.57%	18,438	5,900
Samos	112,745	27,701	19.72%	140,447	31,800
Serifos	8,507	173	1.99%	8,680	3,640
Sifnos	18,340	293	1.57%	18,633	6,390
Skeros	15,775	492	3.02%	16,266	4,620
Semi	14,024	262	1.83%	14,285	3,900
Seiros	89,252	5,524	5.83%	94,776	21,700
Chios	184,146	26,289	12.49%	210,435	45,700
Rhodos	718,685	117,712	14.07%	836,397	206,700
Crete	2,372,760	654,493	21.62%	3,027,253	655,100
Total	4,833,321	998,665	17.12%	5,831,986	

Table 34: Non-interconnected autonomous power systems (islands) - Annual Electricity Consumption (Demand) 2010 – 2017 (MWh)								
Non-interconnected islands	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
St Eustrations	1,058	1,066	1.102	1,075	1,115	1,118	1,096	1,095
Agathonisi	522	542	599	642	650	702	749	727
Amorgos	9,816	9,633	9.354	9,129	9,334	9,865	10,069	10,710
Anafe	1,110	1,137	1.199	1,179	1,223	1,259	1,277	1,298
Antikythera	228	238	216	241	243	261	255	276
Astepalaia	6,997	7,022	7.089	6,670	6,599	6,772	6,856	7,008
Donoussa	676	717	667	690	721	810	841	1,016
HEreikousa	710	664	746	746	697	795	832	879
Thera	117,957	120,057	120.817	120,199	135,772	152,375	164,060	181,674
Ikaria	28,845	29,096	28.977	27,613	27,423	28,658	27,129	28,047
Karpathos	37,829	38,784	38.988	36,931	36,928	37,966	37,799	37,319
Kythnos	8,309	8,719	8.672	7,991	8,240	8,607	9,005	9,586
Kos-Kalemnos	351,959	361,514	361.681	352,984	351,942	367,337	368,521	382,075
Lesvos	308,454	307,864	300.822	288,230	285,542	296,582	297,670	299,860
Lemnos	62,710	61,795	61.743	59,672	58,486	60,244	59,831	60,411
Megisti	2,751	2,973	3.126	3,005	3,152	3,207	3,479	3,549
Melos	45,819	48,272	49.952	45,402	47,885	49,834	47,642	49,181
Mykonos	115,071	113,615	113.027	112,978	125,916	130,123	135,604	144,403
Othonoi	674	709	688	632	634	634	601	645
Paros	208,206	207,254	203.622	194,740	203,727	212,569	217,466	225,755
Patmos	16,738	17,825	17.475	17,020	17,019	17,788	17,477	18,438
Samos	151,017	150,604	146.503	137,315	136,178	138,186	138,050	140,447
Serifos	8,162	8,299	8.153	7,654	8,178	8,358	8,202	8,680
Sifnos	17,966	17,905	17.364	16,521	17,047	17,617	17,984	18,633
Skeros	16,150	15,698	15.549	14,782	15,073	15,955	15,663	16,266
Semei	15,054	15,031	15.275	14,662	14,132	14,649	15,175	14,285
Seros	107,270	104,608	103.443	95,302	95,227	95,202	93,021	94,776
Chios	214,449	215,739	212.476	200,042	196,993	202,519	205,833	210,435
Rhodos	764,401	780,413	790.593	760,658	760,187	791,768	814,488	836,397
Crete	3,014,392	2,945,881	2.944.351	2,825,132	2,866,699	2,898,169	2,975,755	3,027,253
Note: most of the 32 autonomous power systems include more than one island (micro islands)								

The island of Crete opened its market to alternative electricity (conventional fuel) generators, on June 2016. By the end of the year 2016, 7 alternative suppliers had been activated in the local market, with electricity supply shares moving from 0.1691% up to 1.9656% and a sum of 6,59% of the total electricity supply of the island. In 2017, RAE decided[4] to open the electricity supply activity to all non-interconnected islands as of 1 January 2018.

Supply Analysis by Participant and Voltage Level in Crete and Rhodes

Until November 2017, thirteen (13) alternative suppliers with representation rates ranging from 0.02% to 0.62% and a total of 14.55% of alternative supply of the island were actively participating in the local market, which is increased compared to 2016. The total consumption energy in Crete's power station, in November amounted to 196,387.59 MWh, according to the current monthly clearing.

The openness of the market of the second largest non-interconnected island (Rhodes) and the openness of the other islands markets depends on the progress to be achieved by the implementation of network's supply code. The infrastructure development based on the annual development plan of DSO (DEDDIE S.A.) for the non-interconnected islands must be approved by RAE.

From January 2017 until November 2017 eleven (11) alternative suppliers were active in Rhodes with representation rates ranging from 0.0008% to 1.75% and a total of 5.44% of the alternative supply of the island. Total energy consumption in Rhodes' power station for November amounted to 41,368.48 MWh, according to the current monthly clearing.

RAE, by Decision no. 908/26.10.2017 (Government Gazette B 4461/19.12.2017), decided the disengagement of all non-interconnected Island systems from the deviation scheme for electricity supply from 01.01.2018 according to Commission Decision 2014/536 and paragraph 1 of Article 137a/2017 of Law 4001/2011. The exclusion in the electricity supply sector was made with transitional period infrastructure of application of the NIIs' Code, in a similar way as it is already taking place in the systems of Crete (from August 2016) and Rhodes (from in January 2017).

3.4.3. Other Regulatory actions in NIIs

- Years 2016 and 2017, were crucial in the field of supply to NIIs. In 2016, it was the first year of operation of independent suppliers, except from PPC S.A., under the provisions of the institutional framework, the provisions of the NIIs Code, but also of the approved Operator's Action Plan for NIIs. In the first month of market opening, six (6) new suppliers were directly involved with representation shares ranging from 0.0007% to 0.5083% and a total of 0.61% of the islands' supply. By the end of 2016 there were seven (7) independent suppliers with representation shares ranging from 0.1691% to 1.9656% and

[4] RAE Decision 908/2017

a total of 6.59% of the supply on the island. In 2017 RAE decided to open the electricity supply activity to all NIIs by 1 January 2018.

The Authority, by decision no. 908 / 26.10.2017 (Government Gazette B 4461 / 19.12.2017), decided the disengagement of all non-interconnected Island systems from the deviation scheme for the supply of electricity from 01.01.2018 according to Commission’s Decision 2014/536 and paragraph 1 of Article 137a / 2017 of Law 4001/2011. This disengagement in the electricity supply sector happened with infrastructure for the transitional period of application of the NIIs Code, in a similar way as is already taking place in the systems of Crete (from August 2016) and Rhodes (from in January 2017).

- Pursuant to Article 4 of the operative part of the Deviation Decision, RAE with the Decision no. 469/2015, set up the “Committee for the alternative ways of electricity supply to the non- interconnected islands” consisting of members of all relevant Operators (ADMIE, DEDDIE, NIIs Operator and DESFA) with a mandate to explore of technical and economic choices for non-interconnected islands and the publication of a decision with regard to the most economical way of electrification of NIIs through their interconnection with the National Electricity Transmission Network or the interconnected Distribution Network on the basis of the most economically feasible interconnection solution, or by continuing its electrification as NIIs. The Committee submitted its First Study to RAE, in March 2016. The study examines alternatives for electricity supply to the NIIs from the technical and the economic perspectives. The development of additional studies and reports regarding; the needed software in NIIs, data monitoring and analysis techniques, the managing flows and congestions in NIIs decided by RAE in 2016 (Decision no 147/2016).
- The Commission's work continued in 2017, with a test of autonomous interconnection systems of the southern and northern Aegean islands. In December 2017, the Commission submitted to the relevant Operators ADMIE and DEDDIE the First part of the Second Conclusion concerning the islands of the Southern Aegean (Dodecanese). The second part of the Conclusions, concerning the Northern Aegean islands, will be submitted in 2018, as further processing is needed. It is noted that while initially looking at a single transmission network solution configuration which would include all the islands of the Aegean Sea and would be connected to the National Transmission Network in more than one points, it was found that the most appropriate solution is the provision of two separate systems - interconnections, namely: One which includes all the islands of the Southern Aegean (Dodecanese) and is the subject of the first part of the Conclusions and another one concerning the islands of the Northern Aegean, part of which was considered that requires more analysis and will be submitted shortly. Consequently, the examination of the islands of the Northern Aegean is not dependent on that of the islands of the Southern Aegean. The points of the first part, which are of particular interest to the findings reached in this Conclusion, can be summarized as follows:

1. Autonomous Development using natural gas is significantly more economical than using petroleum products.

2. The direct interconnection of the Dodecanese with Attica is on priority rather than through Crete, because it allows the independent implementation of the two interconnections, while greatly reduces the need to maintain local backup production and is more economical.

It is therefore unreservedly proposed to solve the direct interconnection of the Dodecanese with Attica, because it is the most economical of all other possible solutions, while in addition it excels in Autonomous Development with regard to the exploitation of local RES and presents the least implementation difficulties. Finally, in order to support the work of the Commission, and in particular the preparation of studies and analysis, RAE assigned a project in 2017 (RAE Decision 143/2017) concerning the Developing of a software tool to analyze complicated interconnections and the publication of studies.

- Actions of full implementation of the Code's provisions are based on of the Operator's Action Plan which was approved by RAE's Decision No. 389/2015 and foresees the timetable for implementation of all relevant mechanisms and infrastructures.

  In compliance with the Deviation Decision, in February 2017, DEDDIE submitted to RAE for approval the first Progress Report of the Action Plan Implementation for Infrastructure in NIIs. The assessment of the 2017 Report found that most actions to develop the relevant infrastructure are covered by the NII Code, while the majority of time slides that occurred in individual tasks, which do not modify the critical time management of the above major infrastructure projects, except for the development of an Energy Control Center in Athens and Local Control Centers in Crete and Rhodes. By decision No 907/2017 of RAE on Progress Report on the Implementation Plan for Infrastructure in NIIs for the year 2017, the Authority highlighted the urgent need to complete the core infrastructure projects in accordance with the approved timetable (Decision No 389/2015), in order to achieve market opening for NIIs on equal terms for the field suppliers/producers in them and the establishment of transparent management procedures, information, certification and control throughout the wide range of activities of energy production. This Decision was notified to the European Commission.

- As for major infrastructure projects in the NIIs, a major development was constituted by Law 4414/2016, whose provisions, among others, have incorporated into the Greek legislative framework orders by the Deviation Decision 2014/536 /EU of the European Commission in the field of licensing /installation of new production potential by conventional units in NIIs, such as the operation of stand-alone electrical systems. The submission of a binding schedule specifically for permits issued before 1 August 2016, and regulations for the authorization of the units are considered necessary as long as the choice of how to electrify the NIIs and the implementation of approved solutions for the interconnection of the NIIs with the mainland of the country remains under consideration for the interconnection to be the most economical and long-term solution for their electrification. DEDDIE submitted in 2017 the first progress report of the Infrastructure Implementation Action Plan for the NIIs.

- RAE, within its responsibilities under the provisions of article 150 of Law no. 4495/2017 (Government Gazette A '167/2017), according to which "the holders of electricity production licenses from Hybrid Stations in NIIs who have signed a contract of association with the Network Operator before 31.12.2015 and who have been licensed to install their equipment before that effective date as well and holders of electricity generation licenses from Hybrid Stations in NIIs that have been wholly or partially incorporated into EU-funded programs before that date, sign a contract for electricity sale pursuant to article 12 of Law 3468/2006 (A '129).

3.4.4. Emergency response system

In the context of implementing the provisions of the NIIs Code and on the basis of the way of Emergency Response, RAE held a Public Consultation on Amendment of Articles 152 and 155 of the Electrical System Code of Conduct of Non-Interconnected Islands to address emergencies. There has been satisfactory participation and RAE will take relevant decisions in 2018.

Regarding the way of handling emergency needs, the installing of an additional rented capacity and the approval of its cost, the following procedure was determined by decision of RAE's plenary session:

1. The NIIs Operator shall immediately notify RAE in accordance with the NIIs Code, by the end of the next day of the event, for the emergency.
2. The NIIs Operator shall submit to RAE within the above specified time limit a suggestion to grant a production license if an additional potential authorization is required by specifying: the amount of power, its price, and the time required to repair the damage.
3. The Producer, upon the recommendation by the Operator, should submit within a reasonable time of one month from the occurrence of the event, to RAE the necessary application for a production license in order to cover the emergency.
4. The NIIs Operator shall submit within 30 days of the expiry of the Emergency to RAE for approval, an assessment report, in accordance with Article 155 of NIIs Code.

In any case, the NIIs Operator should validate (proficiency analysis based on demand, availability of existing capacity, reserve requirements) it is advisable to hire additional capacity in order for RAE to approve its cost.

A decision by RAE for the approval of the Model Contracts is expected within 2018 Linking Producers to NIIs. It is noted that, following the approval of these contracts, they will be annexed to the NIIs Code of Conduct as an integral part of it and within a period of 2 months in accordance with paragraph 2 of Art. 235 of NIIs Code, Producers must submit a full request to the Operator, in order to result in Connection Agreements of their stations in compliance with the Model as approved by the Authority.

3.4.5. Statement of Objection and Hearing of the NIIs Operator regarding Public Service Obligations

RAE, within its remit, as provided in the provisions of the Articles 3, 13, 22, 23, and 34-36 of Law 4001/2011, monitors and controls the energy market, inter alia, as regards the respect of the legislative framework for the proper functioning of the market, and removes any distortions or other practices followed by the Participants and the relevant Operators causing malfunction in the smooth outcome of transactions in it. In addition, DEDDIE S.A., based on the provisions of articles 129, 130 of Law 4001/2011 and the provisions of the NIIs Code, manages the Special Account for Public Services in the Non-Interconnected Islands, and in particular in accordance with Articles 170, 179 and 183 of the NIIs Code, must follow the procedure of Monthly Clearance and Annual Final Clearing of Load Representatives in the Market of NIIs, including the issue of the relevant tariffs to them.

However, because RAE observed that from July 2016 until the end of the year, the NIIs Operator allegedly did not follow the relevant process of issuing tariffs for the provision of Public Service in Non-Interconnected Islands (but only asserted amounts to the Load Representatives of the NIIs), in the process of monthly liquidation and in violation of the above provisions of the NIIs Code, without any legislative or regulatory change in the operational framework of Special Account of Public Service Obligations, decided at its meeting on 25.11.2016 to invite the NIIs Operator in a hearing to provide the necessary explanations and clarification on the issue. The call to a hearing was not completed within 2017, and is expected to take place in 2018, taking into account newer data which have arisen in 2017.

3.4.6. Environmental Directives

On 25 November 2015, the European Directive 2015/2193 of the European Parliament and the Council was published on the limitation of emissions of certain pollutants into the air created by medium-sized combustion plants, following the 2010/75 Directive concerning the severe limitation of industrial emissions and gases.

The above directives set strict limits on emissions of gaseous pollutants for the units of production and, in conjunction with strict implementation deadlines and the dates of initial licensing and plant deployment, led to significant limitation on production capacity, especially in the non-interconnected systems of the country.

RAE, regarding these instructions, asked Network Operators of the Interconnected System and the NIIs to examine in cooperation with the producers and the members of the above-mentioned Committee for the alternative ways of electricity supply to the non-interconnected islands, the impact of directives on the security of supply in the country. Then all the necessary measures are to be taken and the necessary actions for the sufficiency and the security of supply of the continental Network and NIIs.

3.4.7. Approval of temporary remuneration to cover the cost of providing Services of General Interest (SGI) for the years 2014, 2015 and 2016

On the basis of the provisions of paragraph 5 of the Methodology of Services of General Interest Non-Interconnected Islands (Government Gazette B. 270/07.02.2014), the NIIs Operator shall provisionally calculate the NIIs' Services of General Interest tariff per NII system, on a monthly basis and after the end of each calendar year, proceeds to final settlement, which is approved by RAE in accordance with the provisions of paragraph 6 of the same methodology.

In this context, DEDDIE submitted to RAE for approval the annual final balance account for the years 2014, 2015 and 2016, as well as the annual remuneration for the provision of Non-Interconnected Islands' Public Service Obligations, per NII System, as calculated according to the Non-Interconnected Islands' Public Service Obligations Methodology, along with all the necessary primary data on which calculations were based.

Furthermore, in accordance with paragraph 11 of Article 20 of Law 4203/2013 which provides that "*The amount of production activity costs from conventional units under these contracts are controlled by RAE and recognized by definition due to the provision of the Non-Interconnected Islands' Utilities Services, on the basis of the legislation in force*", RAE, in order to correctly calculate the consideration of Public Service Obligations for NIIs so that Greek consumers are not burdened with unreasonable costs. For that reason, RAE has carried out a thorough evaluation of the above-mentioned data, based on available data per type of expenditure as provided by in the relevant Non-Interconnected Islands' Services of General Interest methodology.
Based on the aforementioned decisions of RAE, the authorized Services of General Interest Tariff exchanges for the years 2012-2016 for all categories of Social Utilities' Services Tariff amounts to € 3,633,018,648, as detailed in the table below:

Table 35: Services of General Interest Tariff exchanges for the years 2012-2016 for all categories of Social Utilities' Services Tariff

(€)	**2012**	**2013**	**2014***	**2015***	**2016***
NIIs Exchange	783,974,665	771,200,756	673,264,257	601,805,609	482,646,229
Total Social Utilities' Services Tariff Exchange	**843,711,901**	**815,737,404**	**738,109,018**	**672,960,903**	**562,499,422**
***Temporary Exchange NIIs (RAE's Decision 688/2017)**					

Based on all of the above, there was a discrepancy between the amount of Services of General Interest Tariff charges revenues and the approved Services of General Interest Tariff of around € 360 million, which is by far less than the amount of € 735 million that PPC S.A. claims. In view of the above and the observed distortions in the way consumers are charged for Public Service Obligations, the Authority has issued its opinion No. 10/2017 on the reform of the framework, including a comprehensive proposal on the imposed charges, on the account management, as well as on its sources of supply, by suggesting rationalization measures of the framework to the Ministry of Environment and Energy.

3.5. RES

3.5.1. RES Installed generation capacity

The installed capacity of RES units at the end of 2017 amounted to 5,521 MW, showing an increase of approximately 5.1% compared to the one recorded at the end of 2016 (5,255MW). This slight increase, which should be noted that moves on itself is at the same levels compared with the corresponding period of 2015-2016, which amounted to 5.7%, is due mainly to the installation of new wind power plants with a total capacity of 254.6 MW (increase by 10.7% compared to 2016) as shown by the breakdown by technology.

Additionally, from the table No 28 we observe an increase of the power of biomass units by 3.5MW (6% increase compared to 2016). These increments as absolute figures are not significant, however a stable investment activity in these sectors is established compared to 2016, in particular for biomass/biogas technology and (above all) wind power plants. Furthermore, it should be noted that in the light of a change in the institutional framework with the Law 4414/2016 a remarkable increase occurred in the development of the small hydroelectric plants with the new installed power in the year 2017 to 7,6 MW and the overall increase by 3.4% in the period 2016-2017 (the corresponding amounts in 2016 were negligible). For PV technology, the change was very small in 2017, with the construction of some projects that have achieved the pilot competitive process, while for 2018 an initial change is expected, as the construction of many projects of the pilot competitive process, which was carried out, will be completed by RAE at the end of 2016.

Table 36: RES in Greece (excluding large Hydro> 0)

RES Technology	Installed Capacity in 2015 (MW)	Installed Capacity in 2016 (MW)	Installed Capacity in 2017 (MW)	% Change 2015-2016	% Change 2016-2017
Wind	2,089	2,370	2,625	13.55%	10.7%
PV	2,229	2,229	2,230	0.00%	0.00%
PV on roof	376	375	375	-0.20%	-0.10%
Hydro Small	224	223	231	-0.40%	3.4%
Biomass - Biogas	52	58	62	11.50%	6.0%
Total	4,970	5,255	5,521	5.70%	5.1%

3.5.2. RES electricity generation in 2017

The Greek electricity generation mix has a highly diversified structure considering that lignite units generated 16,940 GWh, natural gas units generated 15.400 GWh, RES generated

10,191GWh, Hydro generated 3,500 GWh and import flows supplied almost 10,600 GWh, in 2017.

Figure 14: RES Generation excluding Large Hydroelectric plants

Table 37: RES Generation excluding large hydroelectric plants (2011-2017) MW						
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Biomass	45	47	47	52	58	62
Small Hydro <10MW	213	220	220	224	223	231
PV on roofs <10Kw	298	373	375	376	375	375
PV	1,238	2,210	2,221	2,229	2,230	2,230
Wind	1,753	1,810	1,978	2,089	2,370	2,625
Total (excluding large hydro)	3,547	4,660	4,841	4,970	5,256	5,523

3.5.3. RES and the electricity Market

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

3.5.4. RES projects' licensing

The Ministry of Energy in cooperation with RAE amended the current legislation over RES mainly by virtue of Law 4414/2016. A new support scheme for renewable energy resources (RES) and high efficiency combined heat and power (HECHP) installations published on 9th August 2016. The support scheme intends to incentivize electricity production from RES to contribute to the achievement of the national target set by Directive 2009/28/EU on the promotion of the use of energy from renewable sources at 20% share of energy from RES sources on the EU overall gross energy consumption in 2020. Directive 2009/28/EU, set this target for Greece, based on GDP/capita, energy consumption and other indicators, at 18% share of RES on Greece's overall consumption in 2020. Based on the latest data Greece's RES share on total final gross energy consumption was 15.23% in 2016, with electricity from renewable sources (RES-e) representing almost 23% (2017) of the total electricity generation. Significant new investment still required to reach the above national RES target. In terms of additional RES electricity generation capacity, the current gap which must be covered by the year 2020, if nothing will be changed, is currently in the range of 2,000MW and 2,500MW.

Table 38: Projects with a license/permission of generation (non- operational) approved by RAE, end of year 2017		
Technology	No of Licenses	Capacity Power (MW)
Wind	1,078	22,654.75
PV	589	2,979.52
Hydro (small)	413	921.32
Geothermal	1	8
Biomass	93	378.57
Solar	82	442.2
Hybrid	20	345.05
Co-generation (electricity & heat)	57	341.55
Total	2,333	28,070.96

Technology	Table 39: Number of RES applications and number of generation licenses							
	2016				2017			
	Number of Applications for generation license		Decisions/ Permissions approved by RAE		Number of Applications for generation license		Decisions/ Permissions approved by RAE	
	No	Power Capacity (MW)	No	Power Capacity (MW)	No	Power Capacity (MW)	No	Power Capacity (MW)
Wind	79	429.6	15	178.6	175	1,845.88	14	222.5
P/V	0	0	3	16.89	23	199.45	23	173.5
Hydro small	33	79.52	5	7.62	16	26.11	18	49.66
Biomass	10	27	1	1.5	6	14.87	9	19
Cogeneration electricity& heat	1	4.54	0	0	1	4	1	4.36
Hybrid	56	294.31	1	0.96	96	389.82	0	0
(Tele) heating	0	0	0	0	0	0	1	9,8
Total	179	834.79	25	205.57	317	2,480.13	66	478.82

The main change in the new RES support financial scheme is the abolition of the Feed in Tariff financial support mechanism for new RES projects, larger than 5 MW and the adoption of the new mechanism of sliding Feed in Premium. In addition, the new legislation amended ETMEAR (RES levy) and the structure of the RES financial support account with a view to eliminating the debt in the RES account over a 12-months forward looking horizon (June 2017); the account will be kept annually in balance onwards. The initial amendment on renewable energy incentives had been approved on 4 August 2016 (Law 4414/2016). An amendment which brings several points in line with the milestone has been legislated on 6 October 2016. It also foresees elimination of the debt in the RES account by December 2017, which is longer than the originally envisaged timeframe, but includes a corrective mechanism to prevent further or persisting imbalances of the RES account during this timeframe. Moreover, regular provision of data on the RES account has been agreed with the Greek authorities.

3.5.5. RES new Financial Support Scheme

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

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

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

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

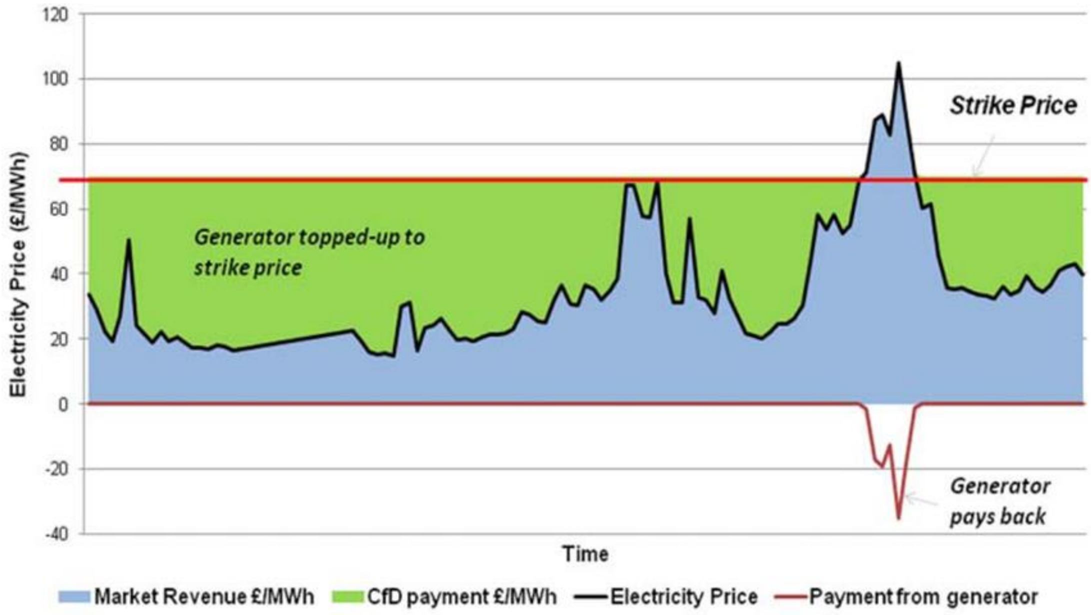


Figure 19: The new Support Scheme in a snapshot

Table 40: Reference Tariffs of Law 4412/2016, Table 1 of Article 4.1(b)		
Renewable technologies and project categories	**RT (€/MWh)**	**Project IRR**
Onshore wind parks in the Interconnected System	98	9%t
Onshore wind parks in the Non-Interconnected Islands	98	9%
Small hydropower ≤ 3MW	100	9%
Small hydropower > 3MW and ≤ 15MW	97	9%
Solar PV < 0.5MW [*Roof-top solar PV installations are regulated by special legislation and hence excluded from the present briefing.*]	1,1 * wholesale electricity market price of the previous calendar year	-
Solar PV ≥ 0.5MW	Competitive bidding	-
Biomass (or bioliquids) from thermal processing ≤ 1MW (excluding the biodegradable fraction of urban waste)	184	9%
Biomass (or bioliquids) through gasification ≤ 1MW (excluding the biodegradable fraction of urban waste)	193	9%
Biomass (or bioliquids) from thermal processing (including gasification) > 1MW and ≤ 5MW (excluding the biodegradable fraction of urban waste)	162	9%
Biomass (or bioliquids) from thermal processing (including gasification) > 5 MW (excluding the biodegradable fraction of urban waste)	140	9%
Landfill gas and biogas from anaerobic digestion of the biodegradable fraction of urban waste ≤ 2MW	129	9%
Landfill gas and biogas from anaerobic digestion of the biodegradable fraction of urban waste > 2MW	106	9%
Biogas released from anaerobic digestion of biomass (energy crops, rural waste and residues, etc.) ≤ 3MW	225	10%
Biogas released from anaerobic digestion of biomass (energy crops, rural waste and residues, etc.) > 3MW	204	9%
Solar thermal without storage system (unless bioliquids are used, in which case see above)	257	9%
Solar thermal with storage system (minimum two hours) (unless bioliquids are used, in which case see above)	278	9%
Geothermal power ≤ 5MW	139	10%
Geothermal power > 5MW	108	10%
Other renewable energy technologies	90	10%

3.5.6. RES Financing

The new RES support scheme, introduced by Law 4414/2016 under the Sliding Feed-In Premium, was approved in 2016 and published on 25.02.2017, according to the no. C (2016) 7272 European Commission Decision on State Aid SA. 44666.

According to the approved Decision from now and above and the provisions of paragraph 1 of Article 7 of Law 4414/2016, "From 1st January 2017, the support scheme in the form of Operational Aid for power stations energy from RES and CHP shall enter into force, competent Body for conducting competitive procedures are: Regulatory Authority for Energy, in accordance to paragraph 5 of the above article. Preamble of these competing procedures was the competitive pilot procedure for photovoltaic installations, which was conducted in December 2016.

In this direction and in the context of the open dialogue between RAE and market, a special conference was organized - Public Consultation at the NTUA at 10 February 2017, on "Permanent competitive offer submission procedures of RES projects". Also, at the beginning of the year 2018, a Workshop - Public Consultation with Presentation of RAE for permanent competitive offer submission procedures for RES projects was organized (24.01.2018 – NTUA), where the involvement of RES and their support framework was presented and discussed with great interest by the public.

The Public Consultation was followed in early 2018 by RAE's Opinion to the Ministry of Energy, according to which:

1. The installed power set which can be auctioned through competitive tendering procedures for the years 2018, 2019 and 2020, within the limits of the following Table, within which RAE announces the auctioned power per competitive bidding procedure according to par. 5 of article 7 of Law 4414/2016:

Table 41: Electricity Generation per Technology type and Auctioned Power

YEAR	TECHNOLOGY	MAXIMUM OF AUCTIONED POWER (MW)
2018	PV	300
	WIND	300
	COMMON PILOT COMPETITIVE PROCEDURES	400
2019	PV	Remaining PV power in 2018 plus 300 MW

	WIND	Remaining WIND power in 2018 plus 300 MW
	COMMON PILOT COMPETITIVE PROCEDURES	Remaining PILOT power of in 2018 plus 400 MW
2020	PV	Remaining PV power in 2019 plus 300 MW
	WIND	Remaining WIND power in 2019 plus 300 MW

At least one competitive tendering procedure will be conducted per technology per year by 2020, at least two common pilot competitive procedures by 2020 and, finally, at least one competitive procedure per region in the period 2018-2019 for cases A to D of article 5 of the no. 184573/13.12.2017 (Government Gazette B4488/19.12.2017) of the Environment and Energy Ministry.

Several instruments are in place to support the financing of RES, including a revenue from the operation of the day ahead market, a revenue from the market clearing and settlement procedures of the day ahead market, a revenue equal to the average variable cost of conventional Generation units (this is important especially for NIIS), a revenue from the energy cost a revenue for CO2 emission rights and Levy on CO2 emission of conventional generation units. In 2016 RES account appeared an estimated deficit of 238.48 million Euro. However, in 2017 RAE with its decision on 22 December 2016 (no 621/2017) proceeded to amendments on the methodology of the calculation of RES Levy. More specific, RAE reallocated the cost of RES Levy financing among the different categories of consumers (HV, MV, LV). This reallocation offered to RES' account a surplus of 42.49 million Euro in the end of the year 2017.

Table 42: RES’ Financing Account	2017	2018
Total Revenue (in million euros)	2,113.88	2,192.35
Day Ahead Market	474.22	521.88
Market Clearing and Settlements	7.17	-
Average Variable Cost of Generation	22.09	24.15
Average Variable cost of generation (NIIs)	126.77	143.74
RES Levy (ETMEAR)	895.97	920.24
Energy Charge (Suppliers)	394.45	374.93
Levy on CO2	33.54	31.9
CO2 emmission Rights	151.85	169.53
Other (licences fee)	-	-
Total Expenditure (in million euros) (November 20176)	-1,.839.,94	-1,.946,.32
For the rest of the year 20176 (estimated)	273.,94	246.,03

According to the Law 4001/2011 article 143 RAE has the authority to monitor RES accounts and to proceed to amendments on the methodology of the calculation of RES Levy (ETMEAR). In December 2016, RAE taking into consideration the reported RES’ account deficits of the previous years, decided to reallocate the cost of RES Levy among the different categories of consumers (RAE’s Decision no 621/2016). 2017 was the year when the Special Account for RES ceased to be deficient mainly as a result of interventions and measures received the previous year. Specifically, at the end of December 2017 the Special Account had a surplus of € 42.49 million.

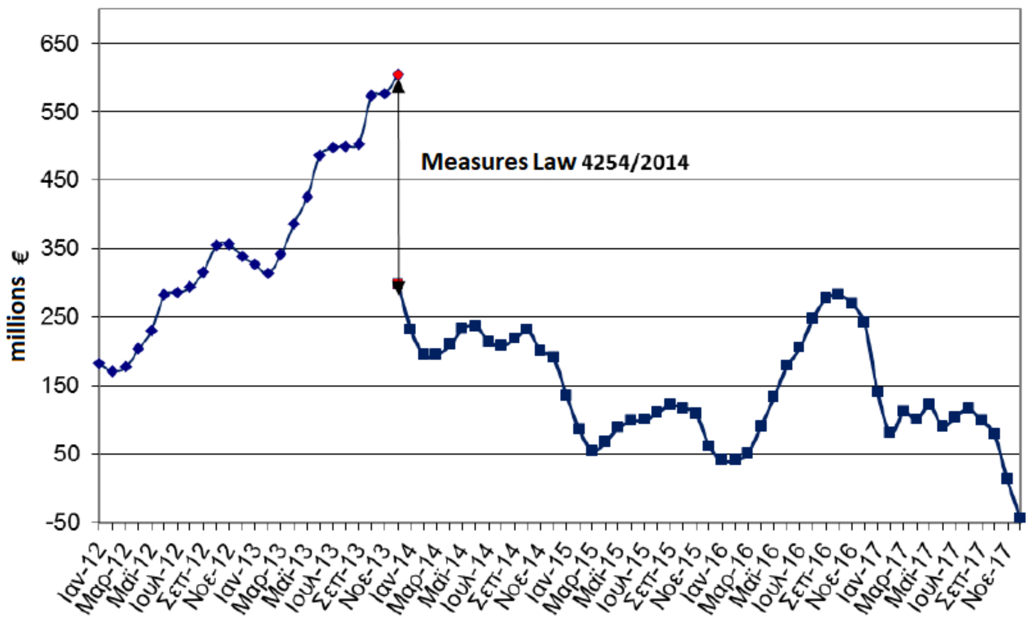


Figure 19: Special Account’s Deficit Progress

The Methodology for calculating the Suppliers Charge (ΠΧΕΦΕΛ), as determined by no. 334/2016 Decision of RAE, aimed at effectively implementing the provisions of the sub-case (bb), case (a), paragraph 3, article 143 of Law 4001/2011, in order to tackle a structural weakness of the market, in the sense that the way of RES/CHP participation to the Day-Ahead Scheduling (DAS), leads to the formation of an SMP, which is lower than the price that would have been formed if RES did not participate to the DAS.

However, RAE in the framework of its responsibilities for monitoring the energy market (Articles 22-23 of Law 4001/2011), found that the amount of the Suppliers Charge (ΠΧΕΦΕΛ) debit was specifically formed in the first half of January 2017 at particularly high levels mainly due to the increased levels of load requirements. For this reason, the Authority with the no. 31/20.1.2017 decided to introduce, in a transitional and restricted time frame, a maximum limit on the obligation to pay the Suppliers Charge (ΠΧΕΦΕΛ).

Table 43: RES Levy Change of Unit Pricing

Customers Classification	Unit Pricing (€/MWh)		Change (%)
	RES Levy in 2017 (Charge per unit €/MWh)	RES Levy in 2018 (Charge per unit €/MWh)	
HV	2.51	2.47	-1.59%
MV >13GWh	2.51	2.47	-1.59%
MV <13GWh	9.76	8.60	-11.89%
MV Agriculture	9.71	8.78	-9.58%
LV Agriculture	10.47	9.39	-10.32%
Households LV	24.77	22.67	-8.48%
Other LV	27.79	26.08	-6.15%

3.6. Consumer Protection

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

Articles 37, paragraph 1, letter n), and article 41, paragraph 1, letter o), of Directives 2009/72/EC require that the regulator, if necessary in collaboration with other Authorities, guarantee that their consumer protection measures, including those in Annex 1, are effective and applied. Table 40 illustrates the implementation status in Greece of the measures set out in Annex 1.

Table 44: State of implementation of measures set out in Annex 1 (Directive 2009/72/EC)		
PARAGRAPH 1	**LETT.**	**IMPLEMENTATION STATUS**
Customers have a right to a contract with their electricity supplier that specifies a series of aspects.	a)	This obligation is covered by the Electricity Supply Code, which sets out the information that must be provided before the conclusion of a contract and the main clauses that must be included in a contract. The same Code also requires that the customer must be provided with the contract in a durable medium. With regards to the services and the service quality levels offered, they must be available to consumers through the Services Leaflet which is published on the Supplier's site. Currently compensation schemes which apply if contracted service quality levels are not met, are not offered by Suppliers.
Customers are given adequate notice of any intention to modify contractual conditions and they are informed about their right of withdrawal when the notice is given	b)	The Electricity Supply Code requires that customers must receive 60 days of notice prior to the application of the modifications to contractual terms, except for price modifications where customers can be informed with the next bill after the price change. In any case, customers have the right to withdraw from the contract at no cost if they do not agree with the new terms.
Customers must receive transparent information on applicable prices and tariffs and on standard terms and conditions in respect of access to and use of electricity services.	c)	The Electricity Supply Code stipulates that contracts must contain a section which clearly summarizes the costs borne by customers for the supply of electricity.
Customers are offered a wide choice of payment methods.	d)	This obligation is derived from the Electricity Supply Code with the additional term that at least one payment method offered by each Supplier must be cost free

General terms and conditions shall be fair and transparent, and given in clear, comprehensible language. Customers shall be protected against unfair or misleading selling methods	d)	The Electricity Supply Code contains the minimum "Principles of information and contact with clients" that cover all the required obligations. Suppliers are obliged to introduce a Code of Contact based on at least the above referred principles.
Customers are not charged for changing supplier.	e)	Supplier switching is free of charge according to the Electricity Supply Code.
Consumers benefit from transparent, simple and inexpensive procedures for dealing with their complaints.	f)	The Electricity Supply Code stipulates that Suppliers must operate a Consumer service department that handles customer complaints according to at least the minimum "Standards of complaints handling" included as a separate section of the Code. Written complaints / enquires must receive a first or final response within 10 working days.
Consumers benefit from information about their rights regarding universal service (electricity customers) of their right to be supplied at reasonable prices	g)	The relevant information for consumers can be found on the Authority's website (www.rae.gr)
Consumers can have at their disposal their consumption data and shall be able to allow any registered supply undertaking to access, by explicit	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.

agreement and free of charge, their metering data		
Consumers receive a final closure account following any change of supplier, no later than six months after the change of supplier has taken place.	j)	Energy Suppliers are obliged to issue a final closure account, within 6 weeks after the contract termination/change of supplier.
PARAGRAPH 2		
Member States shall ensure the implementation of intelligent metering systems that shall assist **the active participation of consumers in the electricity and natural gas supply markets**		In the electricity sector, the timeframe for the roll-out of smart meters is set by Law no. 4001/2011 for the replacement of at least 80% of old meters by 2020.

3.6.2. Ensuring access to consumption data

Ministerial Decision published in GOV Gazette B' 82/27.1.2006 ("Guide for management and periodic settlement of DSO measurements") requires that the DSO must, gather consumption measurements at least every 6 months. In practice, the frequency of recording consumption data is every four months. Consequently, small consumers are informed about their actual consumption at least every four months through their Suppliers bill. Furthermore, consumers can have access to historical consumption data through a simple application registered to their Supplier.

3.6.3. Consumer empowerment

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

3.6.4. Information

To strengthen the consumer’s position in the retail market, in 2014, the Authority, in cooperation with the competent departments of the Ministry of Administrative Reform and E-Governance prepared and distributed to consumers 228,000 pieces of three different thematic brochures through all the “Single Point of Contact” centers located in Attica that represent at least 40% of total population. The aim was to inform energy consumers on their rights related to electricity Supplier switching, out of court dispute resolution and the low electricity tariff for vulnerable consumers.

3.6.5. Quality of DSO Services

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

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

Based on the annual data provided by DSO, on the minimum quality requirements for individual users, the Guaranteed Services program was evaluated by the Authority, for 2017:

Table 45: Performance of Guaranteed Services: Consolidated figures, 2009-2017[5]										
DSO Guaranteed Services (G.S.) 2011-2017										
Service	Guaranteed level Upgrade		Unit	% of failed cases						
	Up to 2013	2014		2011	2012	2013	2014	2015	2016	2017
Instrumentation - connection of meter	3	4	Working days	10.25%	13.58%	12.44%	4.85%	4.24%	8.82%	10.7%
Connection offer with network extension	25	20	Working days	3.93%	4.86%	3.68%	1.17%	0.48%	1.11%	2.73%
Reconnection after client's request	2	3	Working days	3.39%	3.25%	3.47%	1.31%	0.44%	0.29%	0.64%
Reconnection after settlement of debt	Same day	2	Working days	1.58%	1.59%	1.80%	0.55%	0.70%	0.50%	0.36%
Intervention for fuses replacement	4	4	Hours	1.48%	1.56%	1.77%	0.46%	0.55%	0.48%	0.60%
Connection offer for simple works connection	15	15	Working days	2.97%	4.52%	1.35%	0.79%	0.37%	0.68%	1.60%
Observance of appointment time	3		Hours	2.89%	2.05%	1.20%	OUT OF G.S.	OUT OF G.S.	OUT OF G.S.	OUT OF G.S.
Response to written requests-complaints, that require visit	15	20	Working days	0.79%	0.60%	0.66%	0.76%	1.54%	2.05%	3.10%

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

Response to written requests-complaints, without visit	**10**	**15**	**Working days**	**0.11%**	**0.12%**	**0.64%**	**0.18%**	**0.21%**	**0.30%**	**0.68%**
Construction of simple connection	**30**	**30**	**Working days**	**0.53%**	**0.54%**	**0.46%**	**0.36%**	**1.79%**	**4.15%**	**12.24%**
New: Inspection of meter, after client's request		**20**	**Working days**				**8.26%**	**4.20%**	**7.02%**	**8.79%**
New: Disconnection after client's request		**3**					**3.43%**	**2.06%**	**1.75%**	**2.45%**
New: Supply restoration, after network failure/scheduled works, for MV customers		**12**	**Hours**				**3.00%**	**0.22%**	**0.15%**	**0.17%**
New: Construction of new connection with network extension		**40**	**Working days**				**0.79%**	**1.41%**	**2.65%**	**12.31%**
New: Response to written complaints on network quality of supply		**30**	**Working days**				**0%**	**0%**	**1.30%**	**3.09%**
Total No of applications				**880,673**	**912,692**	**848,430**	**728,635**	**651,245**	**705,832**	**736,513**
Total % of failure on guaranteed services				**3.22%**	**3.20%**	**3.04%**	**1.67%**	**1.19%**	**1.32%**	**2.02%**

Following a steady improvement trend in average performance through 2009 – 2015, G.S. failure rates exhibit an increase over the last 2 years, which is more pronounced in 2017 for connection related services.

3.6.6. Vulnerable customers and Energy poverty

In 2015, RAE stepped up its activities to combat energy poverty, by taking more targeted measures. In addition to the Social Residential Tariff, that was applied since 01.01.2011 to five (5) categories of vulnerable customers (Families with Low Income, families with 3 children, long and short - term unemployed and people living on medical support) and the law rate Social Solidarity Tariff that was introduced 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 (for 2 years) 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.

Table 46: Number of customers and total consumption - Residential Social tariff 2011 – 2017

	Residential Social Tariffs 2011 - 2017		**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	656,834	1,315,256,269	70,002	232,886,076
2016	578,311	1,549,216,127	46,562	244,020,079
2017	693,487	1,651,148,973	NA	NA

3.6.7. Handling of consumer complaints

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

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

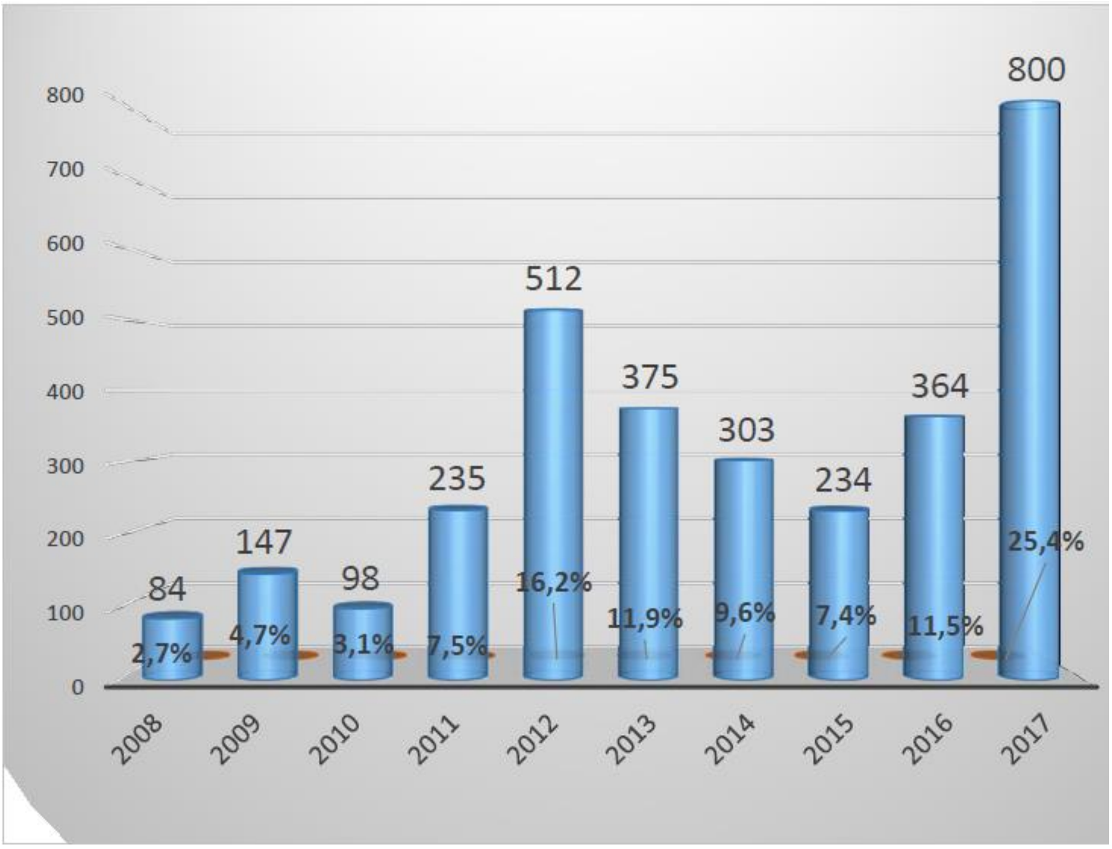


Figure 20: Consumer Complaints in 2017

The total number of reports submitted to the Authority in 2017, amounted to 800, significantly increased (by approximately 119.8%) compared to 2016, reaching the highest level of the last decade. The activation of a large number of alternative electricity suppliers, but also the increased recognition of RAE in the majority of consumers were the main factors that have contributed to the intensity and the range of reporting activity.

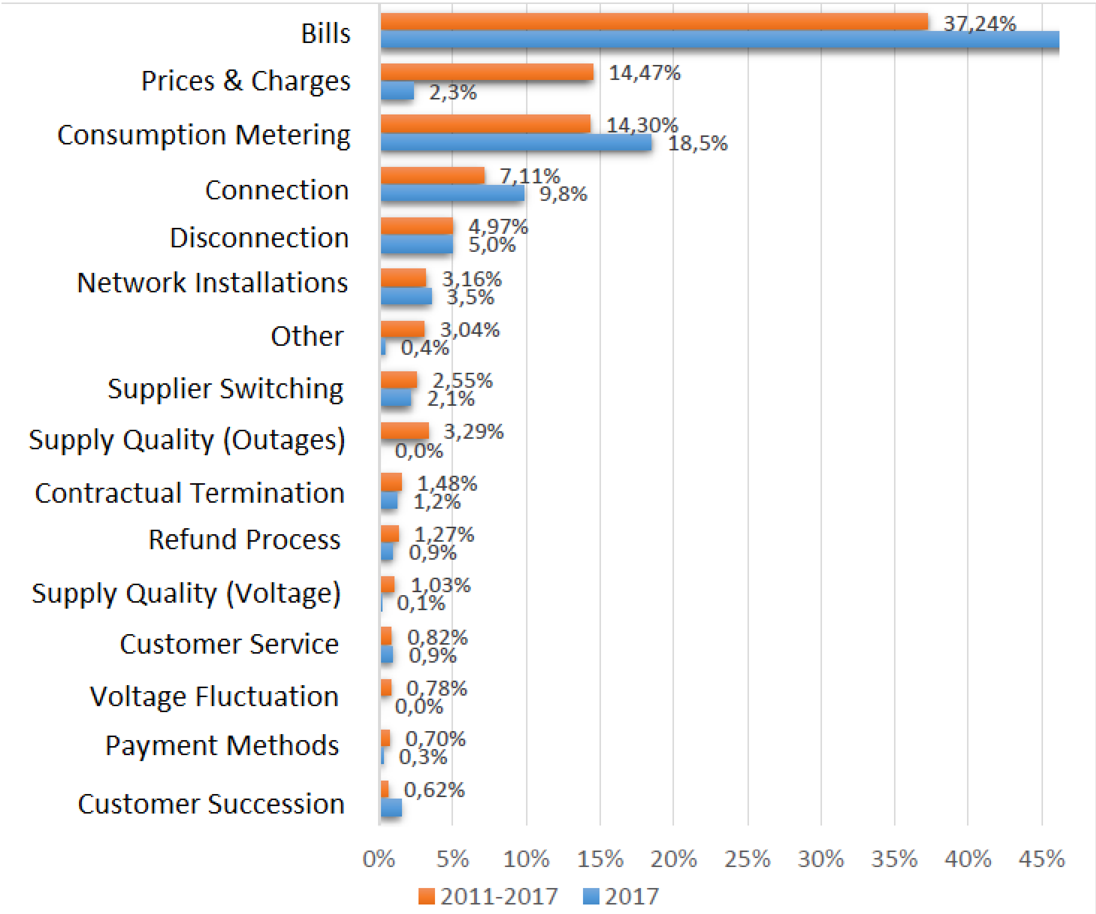


Figure 21: Total Number of consumers' complaints

In the year 2017 there is a relative reduction in complaints about consumption meters in comparison with the data from the year 2016 (from 29.8% to 18.5%). However, the complaints about the connection issues that were recorded in 2017 are a very important part of the time required to install a new metering device and recorded an increase of 4.3%. For many years, the main subject of complaints remains the analysis and explanation of the consumption bills (50.3%).

Consumer reports (requests for information and complaints) which relate exclusively to supply issues for 2017 (494 references) compared to the years 2011-2017 as a whole, focus mainly on the Consumer Account (54.05%), which includes questions and complaints about: a) transparency, clarity of understanding and calculation of charges, b) incorrect charges, c) settlement of debt payment, and d) overwhelming bills.

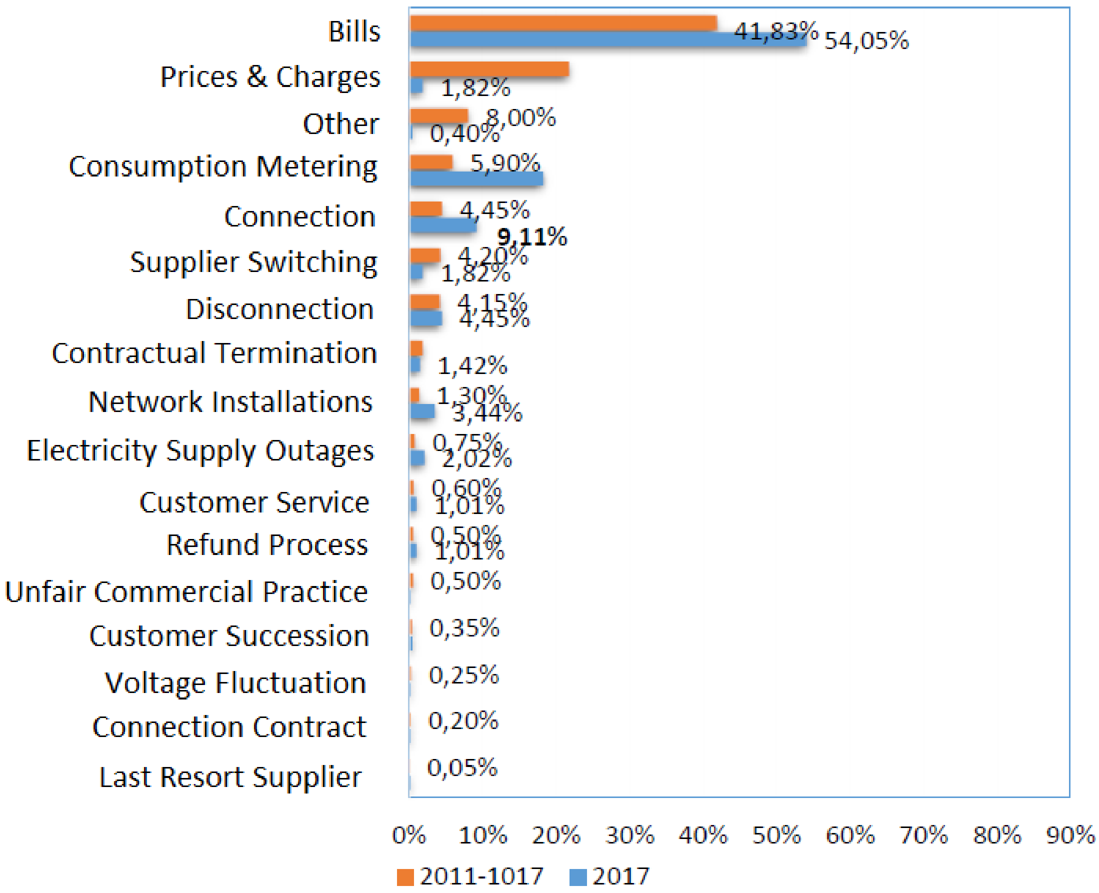


Figure 22: Supply Complaints by thematic category

In 2017, the percentage share was significantly reduced of the reports concerning the Distribution System Operator energy (DEDDIE S.A.) by about 10%. However, protests and reports increased, which relate to the natural gas market, as well as a general set of Alternative Electricity Suppliers, due to the increase of their activity in the retail market. Overall, the complaints concerning PPC S.A. (as Leading Company) increased by 0.9%, while the corresponding complaints to all Alternative Suppliers increased by 2.86%. Among the alternative suppliers of electricity, ELPEDISON ENERGY S.A. is overwhelming by 9% together with PROTERGIA, HERON and WATT & VOLT, which have higher shares in both number and volume of consumption among the Alternative Suppliers of the Retail Electricity Market on MV and LV of the Interconnected System, according to December 2017 data of LAGIE and DEDDIE S.A.

The issues addressed by consumers in relation to DEDDIE S.A. concentrate on greater than 50% of the problems involved in the account (count), and on the consumption metering. Concerning alternative electricity suppliers, the significant issues addressed to consumers focus on the bills, the implementing promotional actions and supplier switching procedure. Finally, gas companies account for 13% of the reports, with main issues of gas consumers: consumption metering, bills, connection and disconnection service as well as pricing charges.

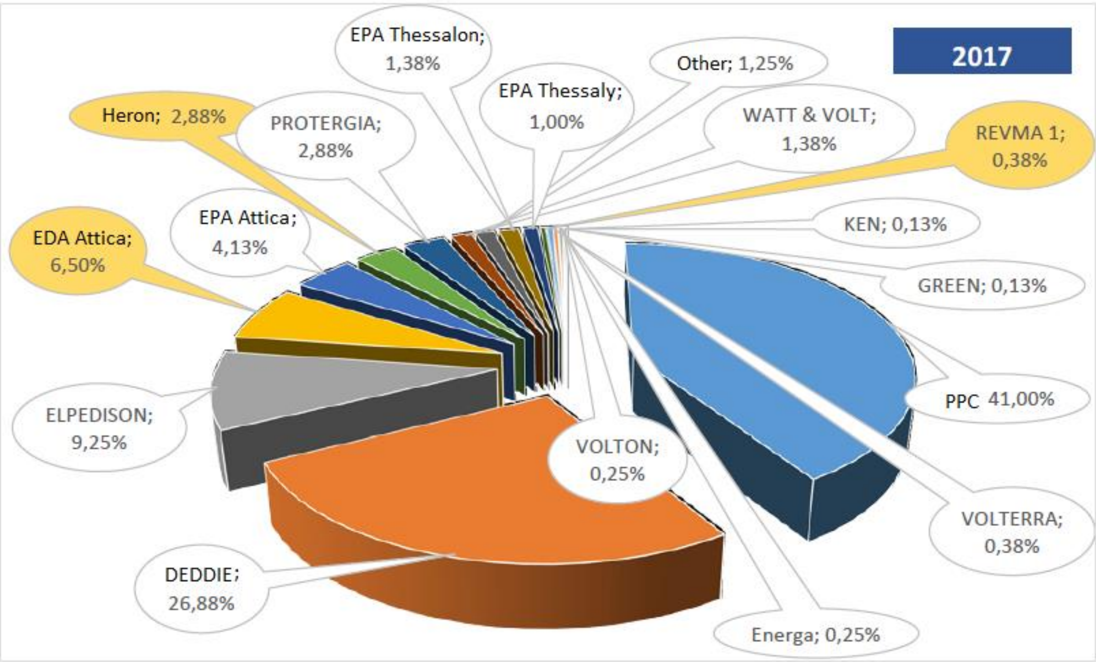


Figure 23: Companies concerned by the reports of consumers submitted to RAE in 2017

3.6.8. Dispute Settlement

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

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

In addition, RAE handles all complaints addressed in written to the Authority, investigates the cases and tries to settle the disputes or makes recommendations to the companies or draws regulations and/or imposes sanctions to the companies if a significant number of consumers is affected.

3.7. Regulatory Decisions and Opinions of RAE

Opinions No. 1/2017 for the amendment of the decision no. D5-EL/B/F29/16027 (Official Gazette B' 1403/06/09.2010) Decision of Deputy Minister for Environment, Energy and Climate Change Issues "Application of the Social Household Tariff" and no. 11/2017 to reform the implementation framework of "Social Household Tariff (KOT)".

In the year 2017 RAE, taking into account the continuing unfavorable economic circumstance of vulnerable consumers, set as a priority in its task the combating of energy poverty. In this context, it issued the no. 1 and 11/2017 Opinions on the amendment and furthermore the overall reform, of Residential Social Tariff implementation framework. During the overall review of the Public Service Obligations' charges framework, the Authority proceeded by reassessing the governing framework concerning the implementation of the Residential Social Tariff for the purpose of streamlining and achieving more effective protection genuinely for vulnerable consumer groups on terms of equal treatment and proportionality.

On RAE's Opinion No 10/2017 on "Reforming the pricing framework for Services of General Economic Interest cost coverage"

RAE, in the exercise of its responsibilities, during the last two years, identified major malfunctions or distortions in the implementation of pricing framework to cover the cost of Public Service Obligations which as a result led to the burden of consumers' electricity bills. In this context, the Authority, having in mind the elimination of distortions and the protection of consumers, has re-evaluated the framework of Services of General Economic Interest charges and formulated the overall Opinion 10/2017 for imposed charges, account management, and its supplying sources to the Ministry of Environment, Energy and Climate Change with measures to rationalize its framework.

4. Regulation and Performance of the Natural Gas Market

4.1. Network Regulation

4.1.1. Unbundling

A) TSO Unbundling

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

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

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

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

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

On 4 August 2016, Law 4414/2016 identified a new process of unbundling of the natural gas Transmission System operator (DESFA) from DEPA S.A.On March 1 2017 the Greek Government decided to go forward with a new tender for the sale of the 66% of the share capital of DESFA. On this occasion, pursuant to Article 63A of the Energy Law 4001/2011, the new investor would need to be (either by itself or as a member of a consortium) a certified European TSO, the Greek State would still retain the remaining 34% of DESFA's share capital, and DESFA would need to be certified under the Ownership Unbundling model. On August 7 2017 it was announced that six (6) offers were made, and on September 9, 2017 that two (2) of them were qualified to the final phase of the procedure.

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 for those inside the EPA areas and Law 4301/2014 turning all non-domestic customers eligible outside the EPA areas)

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 4336/2015 introduced the obligation for the unbundling of the distribution activities from the supply activities by January 1st, 2017. As 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 would be abolished in the end of 2017.

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

- From 1.1.2016, companies were required to keep in their internal accounts separate accounts for each of their activities, about the activities of distribution, supply to eligible customers, supply to non-eligible customers and Supply of Last Resort.
- By 30.5.2016, each company was 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. RAE's decision n. 332/2016 (OJ B 3763/2016) set the relevant rules, according to which the companies filled to RAE their certified internal accounts for 2015.
- By 1.1.2017 the three EPAs and DEPA should move towards functional and legal separation, with the establishment of Gas Distribution Company (EDAs). Legal separation was completed by the companies on time, and three new DSOs were created for the first time (EDA Thessalonikis was merged with EDA Thessalias). The DSOs applied thereafter to RAE for a new DSO license, but the process of updating the Natural Gas License Code had to be completed first before the issuance of the new licenses. Functional unbundling was also monitored by RAE and shared services were only allowed as a transitory measure under strict conditions for only one year.

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.

Moreover, RAE approved a Distribution Network Code for all DSOs. RAE decision n. 589/2016 (OJ B 487/2017) set the main rules for access to the distribution networks in the country. Already a public consultation for an amendment of the Code was initiated and the new rules will be decided in 2018. Similarly, a public consultation was run for the proposed model access contract to the distribution networks and its approval is expected in 2018. Other rulebooks provided by in the Network Code that were submitted to RAE for approval were analyzed and a public consultation for them will run in 2018.

Further, RAE approved through its decisions n. 552/2017 (OJ B 2354/2017) and 784/2017 (OJ B 3685/2017) the tariffs for the ancillary services provided by the DSOs.

Before the end of 2017 RAE had also analyzed and put to public consultation the proposals of the DSOs for a methodology to account for the consumption curves of the final customers.
The new regulatory framework for the introduction of CNG/LNG in the country was meticulously analyzed and a decision by RAE is expected in 2018.

4.1.2. Technical functioning

The National Natural Gas System (NNGS) transports Natural Gas to consumers connected to the NNGS in the Greek mainland from the Greek-Bulgarian borders, the Greek-Turkish borders and the Liquefied Natural Gas (LNG) terminal, which is installed at Revithoussa island at Megara (Athens/Attica region). More specific, there are three entry points into the national gas system:

Entry point	Interconnections' Technical transmission capacity (MWh/day)
1 Sidirokastro (Greece-Bulgaria)	121,600
2 Agia Triada (LNG)	150,000
3 Kipi (Greece-Turkey)	49,000

Table 47: Natural gas import deliveries to the interconnection points (borders) Greece, in 2017 (MWh)		
Sidirokastro (Greece Bulgaria border)	31,176,345	58%
Kipi (Greece - Turkey border)	6,705,459	12%
Agia Triada (Greece - Revithoussa border)	15,986,952	30%
Total	**53,868,756**	**100%**

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

With its Decision 979/2017 (OJ B 4275/2017), RAE approved the annual balancing plan submitted by DESFA S.A. to the Regulator for the year 2018, which included TSO's estimated balancing the network natural gas needs as well as an evaluation of possible balancing gas supply sources for 2018. According to this plan, TSO proposed to acquire balancing gas (in the form of LNG) for the balancing needs of 2018 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. For the year 2018, TSO estimated that the balancing natural gas needs will be recorded to 4.04% 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 868/2017, 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 2016. The corresponding charges include:

- A fixed charge, which covers the fixed costs of the TSO in providing balancing services.

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

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

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

Through the 3rd amendment of the Network Code (RAE Decision 239/17.03.2017, OJ B 1549/2017) a series of new measures were introduced in the Greek system in the spirit of EU Regulation 312/2014 (35 renominations etc). Based on a new proposal submitted to RAE by DESFA for the 4th amendment of the Network Code, and put to public consultation from August 8, 2017 to September 19, 2017, a balancing platform is planned to be operated by the Greek TSO in 2018. The operation of the platform will allow TSO to buy or sell gas from shippers for balancing purposes, giving the opportunity to shippers to trade their imbalance positions.

4.1.3. Network and LNG Tariffs for Connection and Access

A. Transmission System and LNG terminal access tariffs

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

Towards the end of the first semester of 2017, RAE realized that some major shortcomings characterized the forecast of DESFA for the demand of the year 2017 which was considered for the determination of the network tariffs in RAE's decision 352/2016 (OJ B 3513/1.11.2016). To avoid ending up with important over recovery by DESFA at the end of the year, RAE initiated the process for the amendment of the Tariff Code and the respective Tariff for 2017. After a public consultation, and in the spirit of the EU Tariffs Network Code (EC Regulation 2017/460), RAE adopted its decision 871/2017 (OJ B 3720/20.10.2017) for the amendment of DESFA's Tariff Network Code, and its decision 997/2017 (OJ B 4737/29.12.2017) for setting the new Tariff. With the new provisions to the Network Code a mechanism was introduced to allow for the swift adjustment of the tariffs in cases of anticipated within the year considerable over or under recovery, and its application in 2018 resulted in a weighted decrease of the tariffs by approximately 6.17%.

Table 48: Natural Gas Transmission Tariffs coefficients for the Year 2017

Transmission System for each Entry and Exit	$MMSi_i$ (€/kWh GCV /Day/Year)	$TQEi_i$ (€/kWh GCV)
Entry Sidirokastro	0.1927255	0.0001682
Entry Kipi	0.1921027	0.0001309
Entry Ag. Triada	0.0418827	0.0001299
Exit Northeast Zone	0.2854250	0.0004161
Exit North Zone	0.2849859	0.0004494
Exit South Zone	0.4889661	0.0006561
LNG TARIFFS	LCE (€/kWh GCV /Day/Year)	LQE (€/kWh GCV)
LNG Facility	0.14936733	0.0004634

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

B. Distribution System access tariffs

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

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

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

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

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

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

4.1.4. Cross-border issues

During the year 2017 the final recommendation of DESFA S.A. on the Ten Years Network Development Plan 2017-2026 (NDP 2017-2026) was officially submitted to RAE for approval. The NDP 2017-2026 was put to public consultation by RAE between 13.10.2017 and 10.11.2017, and the final decision by RAE is expected to be taken in 2018. The consistency of the NDP is checked against both the regional and the European TYNDP.

Table 50: Gas Supply Authorisation	
	Company
1	DEPA S.A.
2	PROMETHEUS GAS S.A.
3	M AND M GAS CO
4	HELLAS POWER S.A.
5	EDISON HELLAS S.A.
7	ENIMEX GAS ltd
8	TERNA S.A.
9	HERON THERMOELECTRIC S.A.
10	GUNVOR INTERNATIONAL B.V.
11	GREEK ENVIRONMENTAL & ENERGY NETWORK A.E.
12	GASELA GmbH
13	HELLAS EDIL S.A.
14	GREENSTEEL – CEDALION COMMODITIES A.E.
15	WATT AND VOLT A.E.
16	NRG TRADING HOUSE A.E.
17	SOURLAS S.A. CONSTRUCTIONS
18	EPA ATTIKI S.A.*
19	EPA THESSALONIKI S.A.*
20	EPA THESSALIA S.A.*
21	MAKIOS S.A.
22	ELINOIL S.A.
23	PROTERGIA AGIOS NIKOLAOS POWER S.A.
24	ALOUMINION S.A.
25	VOLTERRA S.A.
26	VIENER. S.A.
27	CORAL S.A.
28	PNG LTD
29	AEGEON OIL S.A.
30	Q CAPITAL INTERNATIONAL PARTNERS LIMITED
31	REVOIL S.A.
32	PETROGAS S.A.
33	SINTEZ GREEN ENERGY CYPRUS LTD
34	GS GAS AEBEY
35	NISOGAS SA
36	KEN S.A.
37	GAS TECHNIC I.K.E.
38	ELPEDISON S.A.
39	MOTOR OIL (HELLAS) CORINTH REFINERIES S.A.
40	CORAL GAS AEBEY

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

Furthermore, according to the Gas Law, any person wishing to become a shipper must be registered in the National Natural Gas System Registry, to conclude a (transmission or LNG) contract with the TSO. In 2017, sixty (60) companies were officially registered as potential users of the NNGS, twenty-one (21) of which were active (at least 1 trade a week) in 2017. The NNGS Registry is continuously being processed and updated by RAE.

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

53	PROTOS ENERGY	Third party
54	TRAFIGURA NAT GAS LIMITED	Third party
55	MYTILINAIOS S.A.	Third party
56	Q CAPITAL INTERNATIONAL PARTENS LTD	Natural Gas Supplier
57	EDIL S.A.	Natural Gas Supplier
57	DANSKE COMMODITIES A/S	Third party
58	WATT & VOLT S.A.	Natural Gas Supplier
59	SD PROJECT EAD	Third party
60	GUNVOR INTERNATIONAL B.V.	Natural Gas Supplier

During the year 2017, the total natural gas deliveries at NNGTS entry points amounted to 53.57 TWh compared to 43.8 TWh in 2016, 32.9 TWh in 2015 and 31.7 TWh during the year 2014. Fifty eight percent (58%) of total deliveries came from the interconnection point “Sidirokastron”, twelve percent (12%) from the interconnection point “Kipi”, and thirty (30%) percent from “Agia Triada” (including LNG for balancing purposes).

Until recently, there was no considerable competition in imports of natural gas in Greece, as the share of DEPA gas imports corresponded to more than ninety percent (90%) of total annual imports. In specific, the share of DEPA gas imports in 2015 reached ninety-two percent (92%) of total annual imports, increased up to ninety-five percent (95%) in 2016. Only one (1) other company (big industrial consumer), beyond DEPA, imported natural gas in the country in 2015, representing the remaining eight percent (8%) of total imports. In the year of 2016, DEPA reduced its annual contracted quantity in the GazProm Contract by 1 bcm and along with the Interconnection Agreement for the IP “Kulata (BG)-Sidirokastro (GR)” signed between the TSOs of Greece and Bulgaria, in June 2016, the way was opened to new importers to become active in the Greek gas market. As a result, five companies imported the remaining five percent (5%) of total imports in 2016. The effect of these changes on the wholesale market became clear in 2017, when the share of DEPA gas imports significantly dropped to seventy six percent (76%). As in 2016, five companies beyond DEPA imported gas with their share adding to the remaining twenty four percent (24%) of total imports.

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

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

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

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

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

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

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

Based on the above, in 2017 at least five more companies have imported natural gas through the IP Kulata – Sidirokastro.

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

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

No bundled capacity was offered since Bulgartransgaz announced zero capacity available on a firm-forward basis to the IP because all technical capacity at the Bulgarian side, in the flow direction BG→GR, has already been booked on a long-term basis. On the Greek side, all technical capacity of the IP minus 10% reserved for short term products was auctioned off. Ninety six percent of the capacity offered on the Greek side was bided on and contracted by several shippers (105,000 MWh out of 109,196 MWh), indicating an increased participation of market participants in the capacity auctions compared to one shipper holding capacity in that point.

Further capacity auctions for quarterly, monthly and daily products were executed in 2017 at the IP per the auction schedules announced on RBP, DESFA and Bulgartransgaz websites.

Product trade at the Virtual Nomination Point

With the third amendment of the Gas Network Code now fully implemented by an Entry-Exit System, which is provided by the European framework, the quantities of gas delivered at the entry shall be disentangled from the quantities received at the exit of the system with Virtual Nomination Point (NVP). In addition, the resale process is done solely on the Virtual Statement of Claims. However, a limitation was set that only Transmission Users can participate in the Virtual Nomination Point, that is, those who have bound capacity in the System.

Table 52: Trading Volumes at the Virtual Nomination Point	
Year	***Trading volumes (in MWh)***
2014	**866,403**
2015	**8,826,038**
2016	**24,665,915**
2017	**30,445,814**

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

Source: DESFA, Greek TSO

The trades were executed at the Virtual Nominations Point (VNP) according to Users' Daily nominations submitted to the TSO. Though the TSO has no information regarding the trades' period agreed between the Users. As evidenced by the referred data above this is the over the counter (OTC) spot trade occurring among shippers at the Virtual Nomination Point. Per the provided data by the Greek TSO there has been an increase of one hundred seventy nine percent (179%) in the OTC trade volumes in the trade number from 2015 to 2016 and a twenty three percent (23%) increase from 2016 to 2017.

Finally, RAE, in its role as the Competent Authority on ensuring the implementation of the measures foreseen in EU Regulation 994/2010 regarding security of supply is also cooperating with the Ministry of Energy of Bulgaria. Following consultation with the Bulgarian and Romanian Competent Authorities, which constitute Greece's neighboring countries per Regulation EC 715/2009, in November of 2015 RAE updated the National Emergency Plan and the National Preventive Action Plan, as described in detail in Section XX.

In addition to the above, RAE continues an excellent cooperation with the Italian and Albanian Energy Regulators in the framework of the implementation of TAP project. During 2017, this collaboration continued with the reviewing of the Network Code, as is being developed by TAP.

4.2. Promoting Competition

4.2.1. Wholesale Markets

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

RAE has repeatedly stressed that, under the current operating conditions of the Greek gas market DEPA's commitment for its own gas release (sale) program is currently, the main option for gas supply for third parties - consumers and suppliers - and hence, currently, the only way possible to develop competition in the wholesale gas market, in Greece.

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

DEPA's sales of the previous year as follows: sixteen percent (16%) in 2017, seventeen percent (17%) in 2018, eighteen percent (18%) in 2019 and twenty percent (20%) in 2020. In addition, the auction procedure has been amended as each auction will be conducted in two phases. In the first phase, for the 10% of the auctioned volume, both suppliers and eligible customers have the right to participate, whereas in the second phase, for the remaining part, only gas suppliers have the right to participate.

In 2017, following the methodology for setting the auction reserve price, by Decision 980/15.11.2017 RAE approved DEPA's overhead cost at 0.0087 €/MWh for the annual auction (which for 4,174 TWh equals to 36,400 €) and at 0.025 €/MWh for each of the quarterly auctions (which for 2,782 TWh each equals to a total of 69,600 €) of 2018.

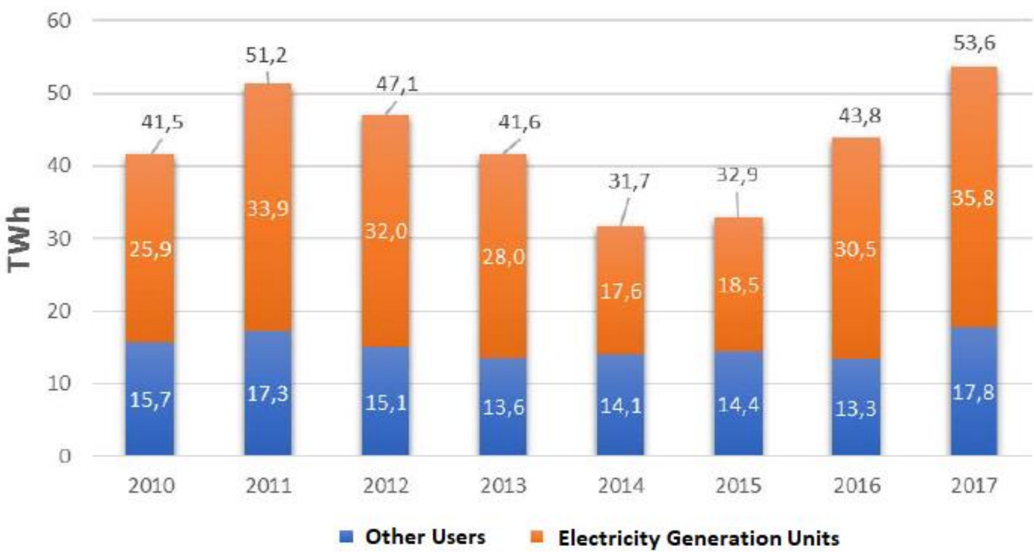


Figure 24: Natural Gas Consumption in Greece

Following the signing and entry into force of the Interconnected System Agreement between of DESFA S.A. and Bulgartransgaz EAD in the year 2016 as well as the implementation of the necessary regulations in the NNGS Management Code approved by RAE within 2017 (3rd revision of the NNGS Code) permitted third parties not only on the island of Revythousa, where as early as 2010 there was an import by a company other than DEPA S.A., as well as to the Interconnection Point Kulata/Sidirokastro, where during the year 2017 at least five companies imported natural gas through Bulgaria's gas system beyond one single Supplier, DEPA S.A. in this case.

All the main changes that have taken place in the natural gas market since the year 2010, when the NNGS Code of Conduct was adopted, until today, have now created a culture of trading among the main gas market participants, in agreement with the rules set by the European Framework for Third Party Access to Gas Infrastructure and the development of a gas market. At the beginning of Virtual Trading Point's creation and the electronic balancing platform by DESFA S.A., following the approval by RAE in January 2018 of the 4th amendment of the NNGS management Code, the operation of the Greek natural gas market is projected to significantly differentiate within 2018. The operation of the balancing platform provides a "signal" for the price of natural gas in the Greek market, shaping so the conditions for the creation of an organized gas market in the country in the near future.

Until recently, there was no considerable competition in imports of natural gas in Greece, as the share of DEPA gas imports corresponded to more than ninety percent (90%) of total annual imports. In specific, the share of DEPA gas imports in 2015 reached ninety-two percent (92%) of total annual imports, increased up to ninety-five percent (95%) in 2016. Only one (1) other company (big industrial consumer), beyond DEPA, imported natural gas in the country in 2015, representing the remaining eight percent (8%) of total imports. In the year of 2016, DEPA reduced its annual contracted quantity in the GazProm Contract by 1 bcm and along with the Interconnection Agreement for the IP “Kulata (BG)-Sidirokastro (GR)” signed between the TSOs of Greece and Bulgaria, in June 2016, the way was opened to new importers to become active in the Greek gas market. As a result, five companies imported the remaining five percent (5%) of total imports in 2016. The effect of these changes on the wholesale market became clear in 2017, when the share of DEPA gas imports significantly dropped to seventy six percent (76%). As in 2016, five companies beyond DEPA imported gas with their share adding to the remaining twenty four percent (24%) of total imports.

In 2016 DEPA reduced its annual contracted quantity in the GazProm Contract and a new importer has become active in the Greek gas market. In 2017 five more companies have imported natural gas from the IP Kulata – Sidirokastro.

RAE, within the framework of its competences regarding monitoring of the Greek energy market, publised for the first time in 2011, data on the calculated Weighted-Average Import Price (WAIP) of natural gas in the NNGS, monthly. The publication of data on WAIP, in combination with the publication of data on daily prices of balancing gas (HTAE) on the TSO’s (DESFA) internet site, allows current and potential market participants to gain a better understanding of the price conditions prevailing in the Greek market, and, therefore, to exploit business opportunities and enhance competition, to the final benefit of consumers. Furthermore, the publication of wholesale prices constitutes a necessity for the organization of a wholesale gas market. Figure 20 presents the monthly WAIP compared to the daily price of balancing gas (HTAE) for the same month, as announced on the internet site of DESFA, from January 2015 through December 2017.

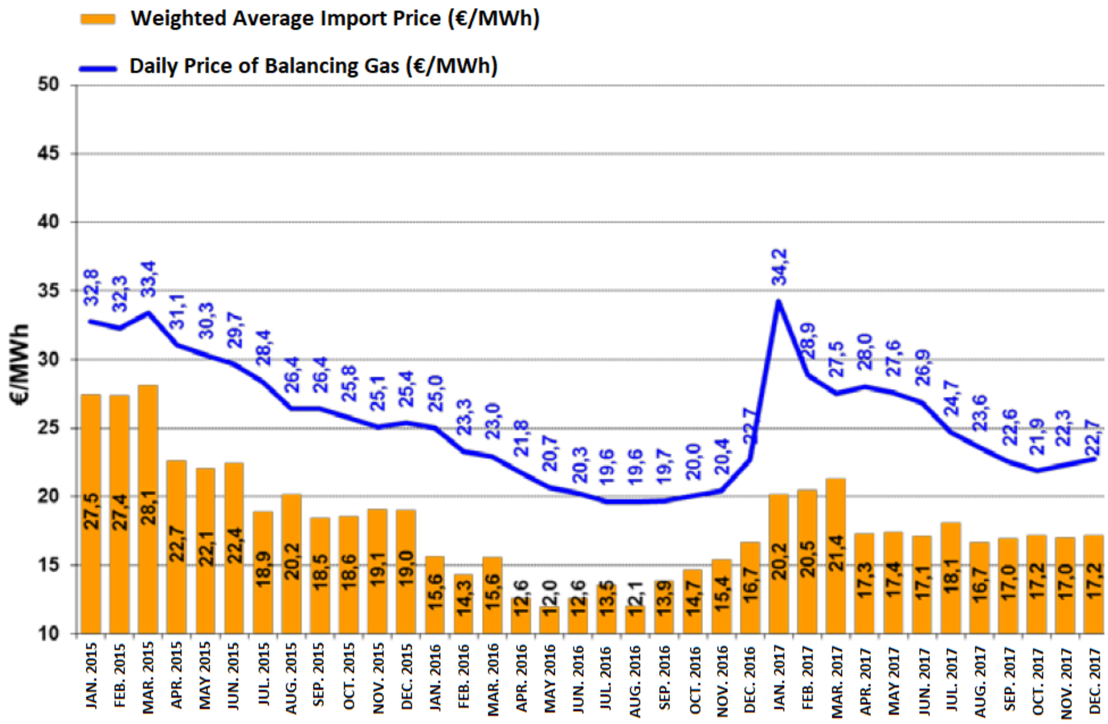


Figure 25: Price Monitoring in the Wholesale Market

The fluctuation of the HTAE in the period January 2016-Dec 2017 is explained by a natural gas supply crisis that occurred in the country over that period. More specifically, during the periods 21.12.2016-26.12.2016 and 09.01.2017-13.02.2017 there was an extremely high gas demand in the country, equal of 47% in relation to natural gas consumption in the previous corresponding winter season 2015-2016, due to increased heating needs because of the very low ambient temperatures and for extracting electricity.

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

4.2.1.1. Monitoring the level of transparency

Market Opening and Competition

There was no new major infrastructure, such as new entry points, LNG or storage facilities, commissioned in 2017. 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 2017, the Revithoussa LNG terminal remains the main channel/opportunity for new entrants in the Greek gas market. Although, as already explained above, in 2017 and due to the capacity cap of DESFA five more companies have imported natural gas from the IP Kulata – Sidirokastro. In any case, as there is still no organized wholesale market in Greece, the price formation remains obscure, and in that regard the main signals to the market participants are derived by the reserve price in DEPA's auctions and the weighted average import prices published by RAE in a monthly basis.

4.2.2. Retail Markets

After the legal and functional unbundling of the aforementioned EPAs, and until the full liberalization of the retail natural gas market in Greece starting from January 1st, 2018, retail prices to non-eligible customers were set for every EPA by RAE decisions 22/2017 and 23/2017. In general terms, retail prices for households, industrial and commercial consumers resembled the cost of a) gas procurement, b) transmission and distribution tariffs, c) taxes, and d) some reasonable margin.

During the year 2017, the total gas consumption in the Distribution Networks was 10.42 TWh, showing an increase compared to 2016 of 16%. An increase in annual consumption was observed in all Distribution Networks other than DEDA's distribution network (Rest of Greece – previously under DEPA SA), in which consumption in 2017 amounted to 2.47 TWh versus 2.61 TWh in 2016, a decrease of about five percent (- 5.16%). A larger percentage increase was recorded in Distribution Network of Thessaly, where consumption in 2017 amounted to 1.60 TWh, compared with 1.14 TWh in 2016, i.e. an increase of about forty percent (40.24%). Respectively, consumption in Thessaloniki's Distribution Network increased by about twenty-one percent (20.85%) (2.82 TWh in 2017 compared to 2.34 TWh in 2016), the Attica Distribution Network at twenty-three percent (22.84%) (3.53 TWh in 2017 versus 2.87 TWh in 2016).

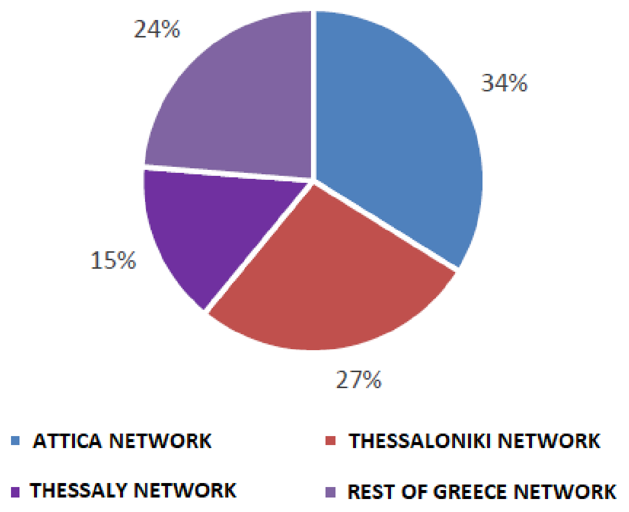


Figure 26: Natural Gas percentage per Distribution Network

The figure above shows the percentage of natural gas consumption per Distribution Network for the year 2017, with the Attica Distribution Network holding the highest percentage of Gas Distribution with thirty-four percent (34%) then follows the Distribution Network of Thessaloniki and rest of Greece with twenty-seven (27%) and twenty-four (24%) per cent respectively, and the Thessaly Distribution Network with the lowest percentage of natural gas distribution with fifteen per cent (15%).

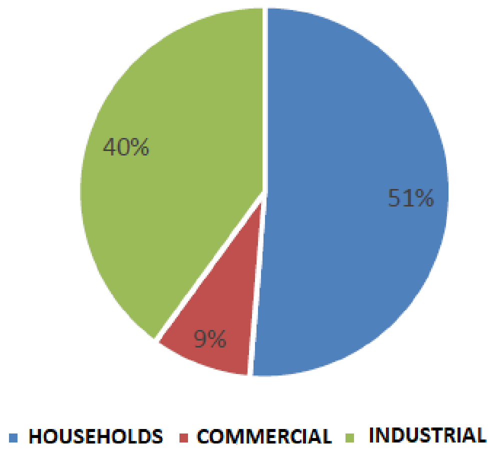


Figure 27: Natural Gas Consumption percentage per Sector

As shown by the data presented above, with households' share reaching fifty-one per cent (51%), industrial users forty per cent (40%) and commercial users nine per cent (9%) for all gas Distribution Networks in the country. More specifically, in the year 2017 household consumption grew by fifty-nine per cent one hundred (59%), from 3.64 TWh to 5.34 TWh, and the industrial sector by twenty per cent (20%) from 3.48 TWh to 4.16 TWh. The commercial sector experienced a reduction in consumption by fifty seven percent (57%), from 2.12 TWh to 0.91 TWh.

In 2017 retail prices reached again 2015 peak levels due mostly to the high demand on account of extreme weather conditions and high levels of electricity production during the first quarter of the year. The table 58 below shows the average household end-user bundled price (€/MWh) for supply and distribution:

Table 53: Indicative, annually-averaged, household tariffs, 2012-2017 (€/MWh)

	EPA Attica	EPA Thessaloniki	EPA Thessaly
2012	62.96	61.40	59.28
2013	57.66	57.19	55.63
2014	54.59	48.87	49.42
2015	48.17	43.85	44.77
2016	40.35	36.56	37.41
2017	50.04	40.08	41.77

The data retrieved from the table above are shown in a graph below:

Table 54: Distribution tariffs per Distribution Network, 2017							
Capacity Charge (€/MWh/h)							
	Attica	**Thessaloniki**	**Thessaly**	**Central Greece**	**Corinth**	**Central Macedonia**	**Eastern Macedonia and Thrace**
Residential	1110.0971	445.1613	516.061	1215.9952		782.555	540.4952
Commercial	1110.0971	446.1613	516.061	1227.1958		819.7896	590.7052
Industrial	4472.5968	1780.8689	2064.5265	7199.916	5726.1368	4511.8945	4812.5942
Cogeneration/ air conditioning	1109.4665						
Energy Charge (€/MWh)							
	Attica	**Thessaloniki**	**Thessaly**	**Central Greece**	**Corinth**	**Central Macedonia**	**Eastern Macedonia and Thrace**
Residential	14.2388	11.7426	12.7956	13.2961		11.4412	11.711
Commercial	14.2388	11.7426	12.7956	11.2185		7.4448	7.2612
Industrial	0.6811	0.284	0.3458	0.5567	1.163	0.4166	0.4853
Cogeneration/ air conditioning	3.7418						

Table 55: Indicative, annually-averaged, Commercial tariffs, 2012- 2016 (€/MWh)			
	EPA Attikis	EPA Thessalonikis	EPA Thessalia
2012	63.96	63.01	60.91
2013	58.66	58.82	57.29
2014	55.59	50.51	51.08
2015	47.17	45.48	46.43
2016	39.36	38.20	39.07

Table 56: Total Number of the active consumers per Distribution Network), 2012-2017						
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Attica Distribution Network	78,000	81,000	86,000	94,000	98,000	106,000
Thessaloniki Distribution Network	155,000	164,000	172,000	196,000	210,000	222,000
Thessaly Distribution Network	55,000	62,000	67,000	78,000	85,000	92,000

Table 57: Natural gas demand by sector in 2017 (bcm)		
Power Production		3,103
Other Customers	**Customers connected to HP network**	0.636
	Distribution Networks	0.903
	CNG quantities	0
Reverse flow & FYROM		0.002
Small Scale LNG		0
TOTAL		**4,645**

4.3. Consumer Protection

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

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

4.3.2. Definition of Vulnerable Customers

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

- People with permanent disability caused by physical, psychological or mental impairment (people with movement disabilities, the blind and, generally, the sight impaired, the deaf, those who have difficulty in understanding, communication and adaptation, patients with atherosclerosis, epilepsy, kidney failure, rheumatic diseases, heart diseases, etc.).
- People suffering from temporary injury or disability caused by physical, psychological or mental impairment.
- People with limited ability for professional employment, due to chronic physical or mental illness or injury.

- People over 65 years of age, if they live alone, or with another person over the age of 65. Beneficial measures for the above domestic gas customers “with Special Needs” include:
  - Prohibition of disconnection due to an overdue debt, during the November to February winter period. Relocation of the consumption meter, for the customer with special needs to have easy access to meter readings.
  - Telephone service for blind customers, to be informed on meter readings.
  - Free visit to special needs customers, to inform them on safety measures in case of an emergency.
  - The customer with special needs has the right to assign another person for
  - Communication purposes (receiving bills, messages, etc.).

4.4. Security of Supply

During 2017, RAE’s activities regarding security of supply (SoS) were focused mainly on the update of the Risk Assessment Study, an obligation of RAE as the Competent Authority of Greece based on the provisions of European Regulation 994/2010 concerning measures to safeguard security of gas supply.

In collaboration with the gas and electricity TSOs (DESFA&ADMIE) as well as the Gas Distribution Operators, the involvement of Suppliers and NNGS Users and the Ministry of Energy, RAE submitted the second amendment of the Risk Assessment Study to the European Commission according to the provisions of the European Regulation 994/2010.

The updated Risk Assessment has also incorporated the following:

- ✓ Brief description of the basic European and national legal and regulatory framework regarding security of gas supply of Greece.
- ✓ Presentation of the stakeholders and parties that are engaged in the Risk Assessment Study
- ✓ Revision of demand historical data, profile features and utilization data of the NNGS
- ✓ Revision of risk catalogue and description as well as revision of the crisis scenarios (supply disruption/ exceptionally high demand / LNG cargoes delays)
- ✓ Simulation of crisis scenarios under the latest forecasts od demand for the periods 2017-2018, 2018-2019 and 2019-2020. Twenty (20) scenarios in total were examined with and without the completion of the upgrade of Revithoussa LNG Terminal.
- ✓ Impact Assessment of the examined scenarios separately for the Industrial and Electricity Sector and Risk Assessment. A sensitivity analysis for the impact of Power Plants with dual fuel availability has also been performed (3 to 5 units).
- ✓ Calculation of Infrastructure Standard N-1 at national level.
- ✓ Brief description of developments with regional impact.

New Regulation (EU) 2017/1938

The Regulation (EU) 2017/1938 concerning measures to safeguard the security of supply and repealing Regulation (EU) No 994/2010 has introduced significant changes regarding the obligations of the Competent Authorities and has enacted provisions for Regional Cooperation.
Based on these provisions, RAE as the Competent Authority is participating as a member in the Risk Groups Ukraine, Algeria and TransBalkan and more specifically in the elaboration of the Common Risk Assessments of these Groups according to article 7 of the Regulation.
Moreover, RAE has been designated as the coordinator for the TransBalkan Risk Assessment and in that frame, in November 2017, agreed on a Cooperation Mechanism with the Competent Authorities of the rest Member States in this Risk Group, i.e. Romania and Bulgaria.

Infrastructure and SoS

RAE, has been monitoring all the future infrastructure projects that may have an impact on Security of gas Supply.

In that frame, RAE participated in the Work Group that has been formed by the Greek Ministry of Energy (Decision 185877/29.12.2015 and 171795/10.02.2017) for the evaluation of exploitation capabilities of the depleted field "South Kavala" and its conversion into an Underground Gas Storage. In October 2017, the Work Group concluded its work and has submitted a Study to the Minister where it describes the contribution of the UGS could have on the Greek gas market and especially on the Greek Security of Supply. RAE's opinion is included in the study, regarding the significant contribution of this infrastructure project in the enhancement of the energy security of supply. A feasibility study was also performed, and a task plan has been proposed. This project is included in the 3rd PCI list.

4.4.1. Monitoring Balance of Supply and Demand

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 2019-2027 NNGS Development Study.

4.4.1.1. Current demand

The demand for Natural Gas in 2017 recorded 4.9 bcm, out of which approximately seventy percent (70%) came from the power generation sector, as shown in Table 52.

Table 58: Natural Gas Demand per sector in 2017		
	bcm@15^{0}C	Mtoe (HHV)
Power Generation	3.27	2.98
Industry & HP customers	0.67	0.61
GDCs (Domestic & Primarily commercial)	0.96	0.87
TOTAL	4.9	4.46

As depicted in Figure 23, total gas demand in 2017 (4.9 bcm) increased significantly compared to that of 2016 (4.05bcm). This increase comes from all sectors, but the Power Generation sector accounts for approximately 60% of that increase. Natural gas generation units have managed to increase their percentage in the energy mix from 24% to 30%, decreasing the percentage of the Interconnections.

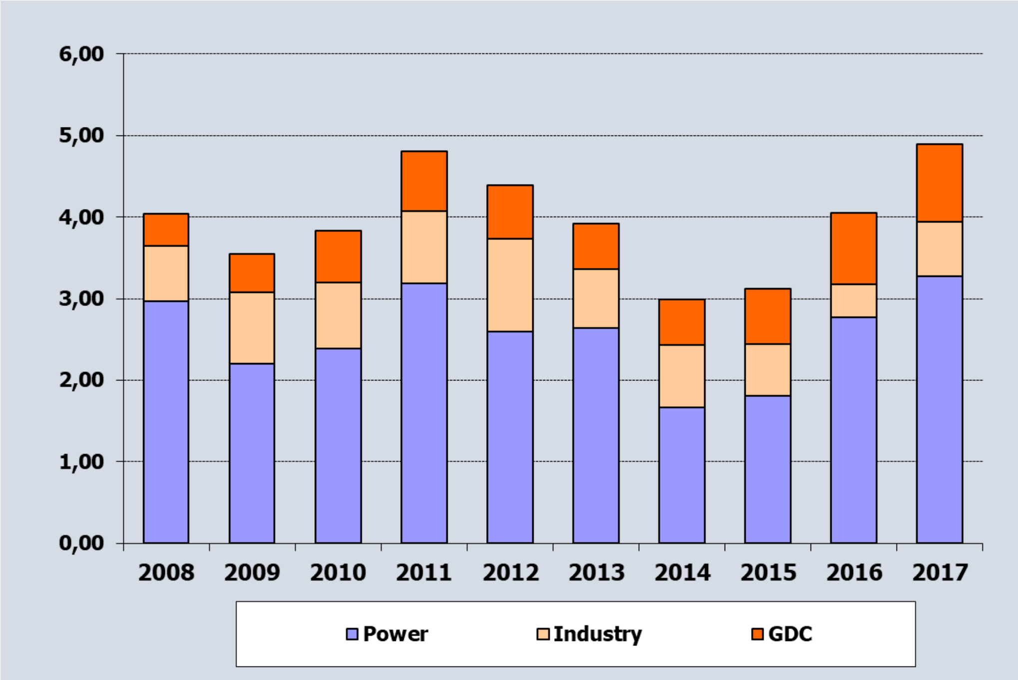


Figure 28: Evolution of natural gas consumption per sector

There is no indigenous gas production in Greece. In 2017, natural gas was imported in the National Natural Gas System through three (3) entry points. As shown in Figure 24, approximately sixty- percent (60%) of the gas imported into the country came from Russia, thirteen percent (13%) was imported from Turkey. The remaining approximately twenty seven percent (27%) was imported as LNG at the island of Revithoussa and was injected into the transmission system from the Agia Triada entry point. Furthermore, 85.3% of the LNG was imported by Algeria, 11.1% from Qatar and 3.6% from Norway.

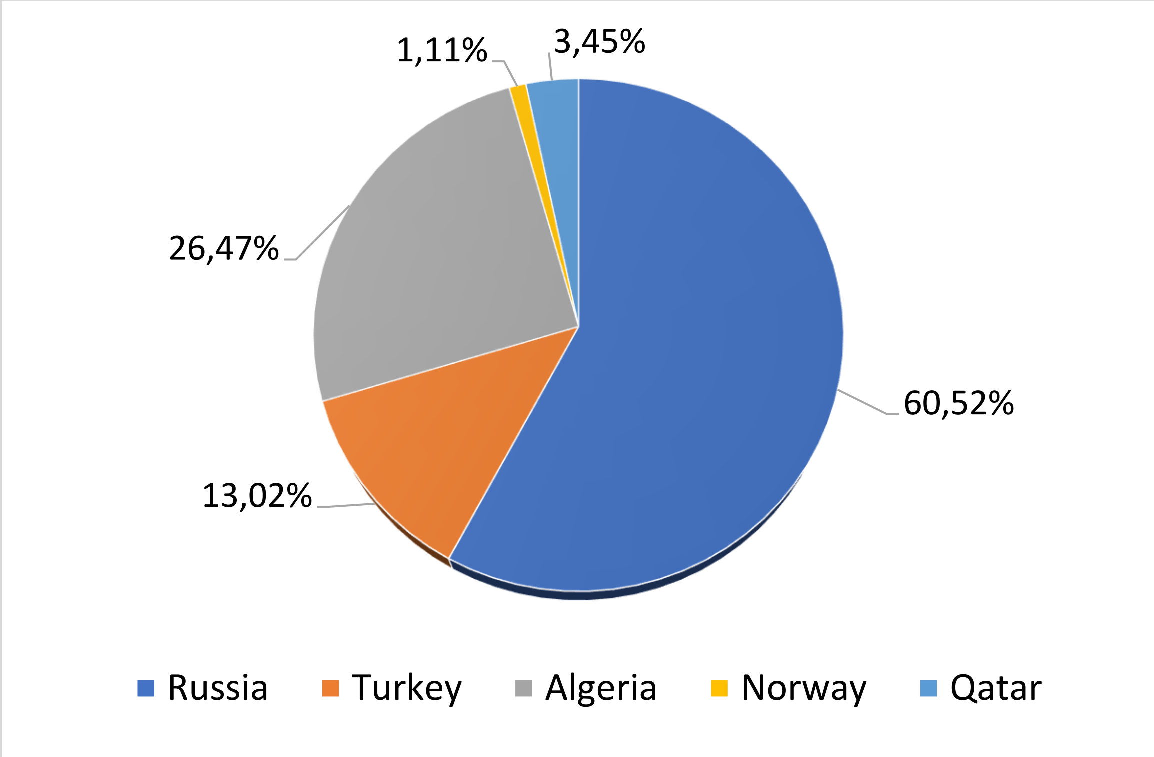


Figure 29: Share of natural gas supply sources per country in 2017

Figure 25 provides the share of imports from each source during the last 11 years (2007-2017). The supply of gas through the existing long-term contract with Russia appears to stabilize at around sixty percent (60%).

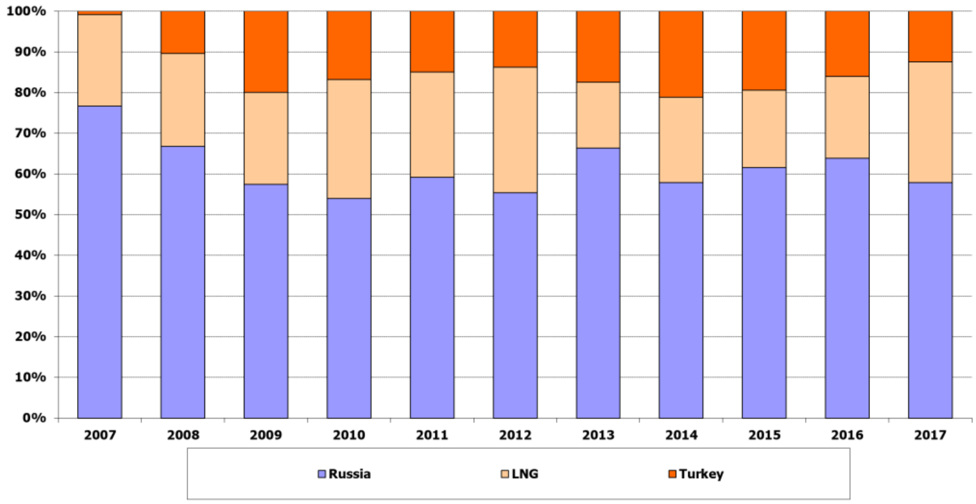


Figure 30: Share of natural gas supply sources from 2007- 2017

4.4.1.2. Projected demand

Natural gas demand is expected to rise in the next three years (2018 to 2020) compared to the natural gas demand of 2017. This is largely influenced by market conditions, the projections of global institutions for Brent crude oil (price) in the forthcoming years and the energy available for imports and hydro production.

Table 59: Future natural gas demand (DESFA's estimates)						
	2018		2019		2020	
	bcm	Mtoe	bcm	Mtoe	bcm	Mtoe
Power generation	2.97	2.7	3.12	2.84	3.49	3.17
Industry	0.6	0.55	0.71	0.65	0.71	0.65
Commercial & households	0.94	0.86	0.99	0.9	1.02	0,93
Total	4.51	4.11	4.82	4.39	5.22	4.76

Security of Supply crises

In 2017, Greece was experienced two gas crises. The first one starting on January 9th and ending on February 2nd, was due to unprecedented high demand both by the electricity and domestic sector due to extreme weather conditions in Greece and in Europe. Natural gas electricity generation was increased significantly while electricity imports dropped down accordingly, as depicted in the following chart.

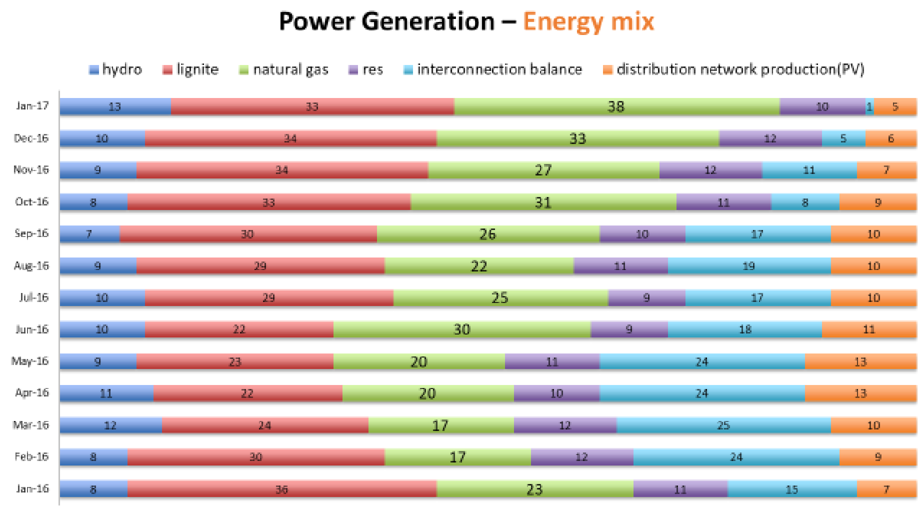


Figure 31: Power generation – Energy mix

On January 9th, at time 14:12, the Operator declared the transmission system at an Alert Level (Alert Status 2), under the terms of the Emergency Plan in accordance with Regulation No 994/2010 of the European Parliament and of the Council concerning measures to safeguard security of gas supply and in accordance with Chapter 10 of the NNGS Network Code. Specifically, the Operator based on data about: a) the LNG reserves, b) the LNG cargo delivery program, c) the natural gas inflows into the interconnection points (borders) of the NNGS, and d) the rising domestic demand of natural gas, declared the system at the Alert level (Status 2).

RAE as the Competent Authority according to Regulation 994/2010 informed the Gas Coordination group.

Under the Terms of the Emergency plan, the TSO informed the Regulator about the situation submitting the estimated (im)balance of Demand and Supply of natural gas for the following seven days as well as the Natural Gas suppliers and the Transmission System operator of the electricity transmission system, ADMIE S.A.

During the crisis, 5 meetings (11.01.2017,17.01.2017,24.01.2017,02.02.2017, 13.02.2017) of the Crisis Management Group took place at RAEs premises where the involved parties (Ministry of Energy, TSOs, Suppliers, Power Producers and system users) under the presidency of RAE participated and discussed on the management of the crisis. Finally, the following measures have been activated following the procedures of the Emergency Plan:

a) To activate the measure of supply interpretability for the Eligible customers (limiting the supply of gas to the eligible customers not less than 60% of their daily demand).
b) To activate the choice of the use of the alternative fuel for the electricity generation units of natural gas (Fuel switch possibility of NG Power Generation plants)
c) To monitor daily the evolution of demand - supply balance
d) Suppliers to increase as possible the gas imports
e) Increased use of hydro

f) Voluntary participation of NG Power Plants in a natural gas management mechanism,
g) To activate the use of electricity interruptible contracts

The above measures had as a result to no forced gas or electricity interruption of supply. On 26 February 2nd, the TSO, after taking into account the scheduled LNG cargo arrivals, the gas imports and the demand estimations declared the end of the status of the natural gas system at Alert level.

On March 12th, and time 06:45 am the Operator (DESFA) declared an Emergency level crisis (Alert Status 3) at the NGTS. Specifically, on 12.03.2017, at 06:00, there was a natural gas leak detected on the 52th km on the high pressure pipeline section of Lavrion, Attiki, (between Stamata and Kalission). 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. More precise, the Operator isolated the section of the pipe between the valve stations of Stamata and Kalission. The Exit Points that were of interest were

- Salfa Anthousa,(CNG Anthousa), there was a limitation on the gas flow, since its demand can also be covered by Salfa Ano Liosia (CNG Liossia)
- Lavrion Power Plant, PPC, there was a total interruption. (in order not to affect exit points that serve Protected Customers)

Exit Points which serve Protected customers and were not affected:

- Athina, demand is covered by MR Athens West and MR Athens North
- Spata, Markopoulo, no change in gas flows (it serves Protected Customers and the airport).

RAE, pursuant to article 10.5 of Regulation 994/2010 and article 1.2 of the Greek Emergency Plan, (Government Gazette 2644/8.12.2015) informed the Commission.

DESFA applied all procedures foreseen in the Emergency Plan and collect up-to-date information from shippers/suppliers and the electricity TSO. The restoration works were completed on March 16th and the commissioning process started. The TSO declared on the same day, at 17:00 the end of the status of the natural gas system at Alert level.