ΡΥΘΜΙΣΤΙΚΗ ΑΡΧΗ ΕΝΕΡΓΕΙΑΣ
REGULATORY AUTHORITY FOR ENERGY

National Report 2019

Regulation and performance of the electricity market and the natural gas market in Greece, in 2018.

Regulatory Authority for Energy (RAE)

Athens, December 2019.

REGULATORY AUTHORITY FOR ENERGY

132, Piraeus str., 118 54 Athens, Greece

Tel.: +302103727400, Fax: +302103255460

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

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

President

Nickolaos G. Boulaxis

(since 23-6-2015)

A' Vise President

Sotirios Manolkidis

(since 23-6-2015)

B' Vice President

Michaella Latta

(since 18-2-2016)

Member

Nektaria Karakatsani

(since 22-6-2015)

Member

Ioannis Anagnostopoulos

(since 19-2-2016)

Member

Apostolos Gotsias

(since 19-2-2016)

Member

Theodoros Zervos

(since 19-2-2016)

1. Foreword

Dear Readers,

During 2018 a series of reforms, both at legislative and regulatory level, have been put in place, aiming at removing market distortions, enhancing competition and promoting harmonization with the EU acquis.

RAE is firmly committed to its goal and mission to design and implement an integrated set of regulatory reforms that will create the necessary conditions for healthy competition in the energy markets by removing market distortions and ineffective practices which create unjustified burden to consumers. Furthermore, continuous and intensive efforts are made to maintain and further develop the necessary energy infrastructure both in the mainland as well as in the islands of Greece, not only to safeguard for security of supply reasons the integration of the non-interconnected islands (NII) to the mainland electricity system, but also to reduce the excessive costs that burden consumers and achieve the country's environmental goals and commitments. At the same time, RAE promotes all necessary reforms which will ensure the participation of Greece in a smooth, organized and efficient way in the integrated European energy market, while at the same time safeguarding the security of energy supply, both physically and financially, in order to ensure the lowest energy costs for households and businesses which are a key driver of growth and support for the national economy.

Moreover, as the energy system continues to be struggling with several challenging issues in the short to medium term, such as the ageing of the lignite generation units, it was necessary for Greece to retain throughout 2018 previously adopted 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.

In this framework and in compliance with the responsibilities assigned to it by the Greek legislation (in particular Energy Law 4001/2011) and the EU law (Third Energy Package), in 2018 RAE proceeded with the adoption of a series of key regulatory decisions, opinions, and recommendations, but also promoted other relevant initiatives and actions. The most significant of these actions are summarized below first, and then analyzed in detail in this 2019 National Report.

Dr Nikolaos Boulaxis

President of RAE

2. Main developments in the electricity and gas markets

2.1 Electricity

In 2018 RAE proceeded with the implementation of "the Target Model"[1] in the Greek wholesale electricity market, based on the European regulations, directives and guidelines.

The Ministry of Environment and Energy, in close cooperation with other competent bodies and RAE, had 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.

According to Law 4512/2018, the Greek Energy Exchange (HENEX S.A.) was founded as the competent body for operating Electricity, Natural Gas and Environmental Markets. As Electricity Markets the law defines the Day-Ahead Market, the Intra-Day Market and the Balancing Market which function as organized markets according to EU Regulation 1227/2011 (REMIT). Based on the provisions of Law 4512/2018, and according to the guidelines already prescribed in the Law 4425/2016 for issuing the Electricity Markets Codes, as those were detailed in RAE's Decision No. 369/2018 (Gazette B' 1880/24.5.2018), the operating rules for the Balancing, Day-Ahead and Intraday Markets were first drawn up by the respective Operators and later approved by RAE. For founding HENEX and covering the necessary share capital, LAGIE S.A. contributed the operation of its sector which includes the activities mentioned in Article 117B paragraph 1 of Law 4001/2011 through a split-off and contribution of the relevant sector to HENEX. Thereafter, LAGIE S.A. was renamed as DAPPEP S.A. Because of the above split-off, during 2018, and pursuant to par. 3, art. 117E of Law 4001/2011, the Electricity System Transactions Code and the Network Code were amended, but also the new Code of the Operator of RES and Guarantees of Origin was issued.

Furthermore, towards a truly coupled electricity market, 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..

In 2018 the new Transitional Flexible Remuneration Mechanism was put into force after the termination of the previous one of 2017. The European Commission, after taking into consideration the constant need for flexible capacity in the System and the situation of the Greek Electricity Wholesale Market (reforms to reach the Target Model), approved the implementation of the new Mechanism founded under Law 4559/2018 (Gazette A΄ 142/03.08.2018) and became operational for the period from 03.08.2018 to 31.12.2019. RAE proceeded, after upon a proposal by ADMIE, to the amendment of System's Network Code. The main

[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).

difference between the two mechanisms is the introduction of bidding procedure for the setting of units' remuneration. In addition, the maximum approved cost of the Mechanism per year dropped to € 175.5 million compared to € 225 million in 2017.

Regarding the Long-Term Capacity Mechanism, RAE after taking into consideration the situation of the Greek Electricity Wholesale Market and the System's need on a middle and long-term base, the EU legal framework, the results of ADMIE's Adequacy Study of the Interconnected Electricity System for the period 2019-2030, but also the relevant decisions of other regulatory authorities in Europe and the decisional practice of the DG Competition of the European Commission, submitted a detailed proposal to the Ministry of Environment and Energy for a Long-Term Capacity Mechanism scheme. The Ministry pre-notified to the European Commission the proposed scheme in October 2018. RAE continues to cooperate with the Ministry for the submission of the final version of the above scheme to the European Commission.

Regarding the auctions of wholesale forward electricity products by the Public Power Electricity Corporation (PPC S.A.), based on the Law 4336/2015, and as a means for the immediate and essential opening up of the retail market to competition, RAE proceeded in all required actions and opinions for the issuance of decisions and the execution of the auctions during 2018, as well as for the preparation of the 2019 plan. RAE also made more stringent the prerequisites for participating in the auctions so as to streamline the whole process with the ultimate goal of introducing more competition to the Greek retail market. .

The development of electric vehicles infrastructures constitutes a main prerequisite for the development of an electric vehicle market at national level. According to Article 53 paragraph 1 of Law 4277/2014, RAE is responsible for issuing an opinion concerning the relevant regulatory framework for the recharging stations and their operation. The final terms and conditions would be set by a common ministerial decision by the ministers of finance, infrastructure and energy. . In this framework, in 2018, RAE run a public consultation for the clarification and the delimitation of regulatory and operational framework for the introduction of electric vehicles charging stations.

In terms of the generation mix in 2018 lignite production showed a decrease of 9.03% (1,480 GWh) compared to 2017 and another increase of 9.97% (1,486 GWh) compared to 2016. Specifically, it amounted to a total of 14.91 TWh (16.94 TWh in 2017). Similarly, natural gas production dealt with a downward trend and dropped to 14.12 TWh (against 15.4 TWh in 2017). The hydroelectric production showed a sharp rise by 46.14%, 5.05 TWh from 3.46 TWh in 2017, changing the downward course of the previous year. RES production and CHP has continued the upward course of the previous year and was equal to 11.11 TWh, recording an increase of 5.16% compared to 2017. Production by other fuels in the Interconnected System was at zero level for a fourth consecutive year. Overall, domestic production showed a slight decrease of 1.31% reaching 45.21 TWh versus 45.8 TWh in 2017.

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 decreased in 2018 by 1% compared to 2017 (in 2017 it had increased by 1.6% compared to 2016). In the HV sector demand significantly grew in 2018 by 1.13%, continuing the upward trend recorded in the previous three years.

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. The High Voltage demand showed an opposite trend. There was a decrease of 1.6% compared to 2017 while it is worth mentioning that in the previous year there was an increase of 1.6% compared to 2016. In January 2018, Distribution Network's demand was reduced by 11.4% compared to January 2017 (+14.2%

in January 2016). This is mainly due to the far colder January of 2017 which made the winter of 2017 to be one of the coldest in the last 30 years. January 2018 was milder and as a consequence the demand was relatively lower. It is worth noting that in December 2018 Network's demand was increased by 5.9% compared to December 2017 mainly because of the lower temperatures in 2018.

RAE, throughout 2018, systematically monitored the course of competition in the energy markets, and regarding financial transactions it proceeded with random testing of arrears of electricity suppliers towards the operators. In this framework several suppliers underwent hearings before RAE regarding their obligation to pay network tariffs to the operators. Moreover, within 2018, RAE issued three decision imposing penalties to the NIIs Operator, the Distribution System Operator and the Network System Operator.

As for the electricity supply in Non-Interconnected Islands, following the opening of the retail market in all Non-Interconnected Islands, 14 alternative suppliers were active, reaching a total of 15.5% market share, in NIIs in 2018.

Regarding electricity network infrastructures, the fast implementation of the projects included in the Ten-Years Network Development plan, and in particular those concerning the islands interconnections, is a basic strategic direction for RAE.

In 2018, RAE's Decision No. 256/2018 was approved under certain conditions the new Ten-Years Network Development Plan (TYNDP) 2018-2027. Following this approval, ADMIE, after taking into consideration the comments submitted during the preliminary public consultation of the draft TYNDP 2019-2028, as well as RAE's guidelines, submitted to RAE the relevant plan for approval with a significant number of amendments. Most of the amendments concerned the importance of faster implementation of the Cyclades and other NIIs interconnection with the National Transmission System in order to alleviate the burden of Social Utility Services and to further improve the quality of supply for consumers in NIIs, but also allow to better exploit RES technologies in the in the islands and help to reach the National Climate and Environmental targets. Finally, RAE put the new amended text of the TYNDP to public consultation and evaluated the responses submitted to it. In this framework, RAE is going to ask from ADMIE more clarifications and supplementary data in order to approve the final TYNDP 2019-2018.

In March 2018, the First Phase of Cyclades Interconnection was inaugurated. The implementation of the First Phase was a really important moment for the country because it was the result of a multiannual endeavor of several institutions of which RAE was historically a major part.

During 2018, also, the "Committee for the alternative ways of electricity supply to the non- interconnected islands", set up initially by RAE with the Decision no. 469/2015 and reinforced by law 4414/2016, submitted the second part of its study to RAE in December 2018. This second part covers the Northern Aegean islands and argues in favor of their interconnection through submarine cables with the National Transmission Network. The islands interconnection would be beneficial for reaching the national energy and climate targets, to alleviate the burden of extra costs for the consumers and for security of supply during the next decade.

Specifically, the security of supply of Crete has emerged as a major national priority over the past few years because of the EU environmental limitations and the termination of the exemption decision 2014/536/EU of the European Commission at the end of 2019. To this end, RAE has coordinated the relevant actions between the network operators and producer PPC S.A. trying to reach the most effective intermediate solution until the full interconnection of the island with the National Transmission Network.

In this regard, the interconnection Crete – Attica, was part of a bundle of Projects of Common Interest under Regulation EU 347/2013 (as amended by Regulation EC 2016/89) between Israel, Cyprus and Greece (known as EuroAsia Interconnector). In October 2017, the Regulatory Authorities of Greece and Cyprus (RAE - CERA) jointly issued the Cross-Border Cost Allocation (CBCA) under certain conditions. However, the sponsor of the project failed to proceed with the implementation of the project according to the set timeline, resulting in a delay of over two years (2020-2022) as testified in a monitoring report of ACER. RAE, being responsible for the effective protection of the consumers, and in view of the special circumstances with the energy adequacy of Crete because of the above delay by the sponsor, deemed absolutely necessary to take the appropriate measures for the implementation of the agreed conditions under the CBCA decision. These measures were based on national and EU law and were prescribed in RAE decision 816/2018, as amended by decisions 838/2018, 1190/2018 and 150/2019. In particular, ADMIE was ordered to create a special-purpose vehicle, as a 100% subsidiary, to finance and construct the part of the above PCI bundle that connects Crete to Attica. That project would need to be in operation by 2022 at the latest. In the above company, Euroasia Interconnector Ltd could buy until 10.12.2018 shares up to 39%. The possibility was also allowed for the creation of a special technical committee to determine the minimum technical specificities for the interconnectivity of all projects in the bundle.

2.2 RES

RAE, within 2018, undertook the following actions in relation to the application of the provisions of Law 4414/2016 in the Greek energy market:

- It issued an Opinion to the Minister of Environment and Energy within the first half of 2018 (Opinion No 8/2018) on the designation, obligations and operation of the Aggregator of Last Resort.
- It issued, within the first half of 2018, Decision No 508/2018 on the "Approval of the Electricity Transactions Code in accordance with Paragraph 3 of Article 117E of Law 4001/2011 (Government Gazette A '179 / 22.08.2011)".
- It issued, within the first half of 2018, Decision No 509/2018 on the "Operator of RES and Guarantees of Origin Code in accordance with Paragraph 3 of Article 117E of Law 4001/2011 (Government Gazette A '179 / 22.08.2011)".
- It issued, within the first half of 2018, Decision No 511/2018 on the "Amendment of the provisions of the Transmission Network Control Code for Electricity (Government Gazette B '103 / 31.01.2012) in accordance with paragraph 1 of article 96 of Law 4001/2011 (Government Gazette A' 179 / 22.08 .2011)".
- It issued, within the second half of 2018, Decision No 640/2018 on the "On the procedure for granting the license to RES aggregators in the electricity market".

RES competitive auction procedures. RES competitive auctions were carried out by RAE using the dedicated online bidding platform on July 2 2018 and 10 December 10 2018, for the three Project Categories below:

- Category I: PV with installed capacity of PPV ≤ 1 MW
- Category II: PV with installed capacity of 1 MW < PPV ≤ 20 MW
- Category III: Wind parcs with maximum capacity of 3 MW < PWIND ≤ 50 MW

The success of the auctions will be determined in the end by the implementation of the projects that were successful during the auction procedures and their connection to the electricity system. RAE, as the competent authority for both the execution of the competitive auctions and monitoring of the energy market, will advise the Ministry of Environment and Energy against any threat to the auctions and the RES energy market, in view of achieving the target of 18% RES penetration by 2020.

Promotion of Hybrid Power Plants in non-interconnected islands. RAE, in light of its commitment to promote the implementation of hybrid plants in the NIIs, issued Opinion 7/2018 which entails a new tariff framework for hybrid power plants in NII, in line with the European Commission's decision "New RES and CHP support scheme in Greece" (SA.44666). In summary, RAE proposed, inter alia:

- Separate pricing of the distributed and non-distributed hybrid power plant energy
- Determination of a single maximum unit price for the distributed energy generated by hybrid power plants in NIIs.
- Conclusion a Sliding FiP Contract for Differences (CfD) for hybrid power plants in NIIs which shall remain valid for a certain maximum period depending on the storage technology used. However, it is proposed to vary the validity of the guaranteed tariffs, depending on the planned time for the connection of each NII to the interconnected system.
- Execution of a pilot tender in a NII, whose connection to the interconnected system is not foreseen soon, aiming to depict the lowest prices that make hybrid power plant investments viable.

Within 2018, RAE also issued Decisions to grant, transfer, modify, renew, revoke and simply acknowledge minor changes to production licenses in accordance with the current legal framework. In this regard, RAE issued 779 acts in total.

2.3 Natural Gas

The current state of the wholesale market

Natural Gas Balancing Manual:

In the context of the 4th Amendment of National Natural Gas System (NNGS) Network Code and in particular the provisions for the operation of the Balancing Network, RAE issued Decision No 546/2018 which approved the Gas Balancing Manual. The main provisions of the manual concern:

- The characteristics of short-term standardized daily and intraday products;
- The auctioning procedures by the Operator and bidding by the Natural Gas Transmission System Users;
- The evaluation process of the submitted bids by the Operator;
- The determination of the calculation methodology for the Balancing Natural Gas Reference Price as well as for the relevant factors for the calculation o the Balancing Gas Marginal Buy and Sell Price;
- The determination of the Upper and Lower Unit Bid Limit

Decisions about Balancing and Operational Gas:

According to the provisions of Law No 4001/2011, RAE, during 2018, issued decisions related to the Operational and Balancing Gas and approved the unit prices and parameters of the cost of operational and balancing gas used in the National Natural Gas Transmission System. RAE also approved the Annual Planning of Gas Balancing and the operational gas study for the year 2019.

In 2018, RAE started planning the necessary steps to create an organized wholesale gas market for the trading of natural gas products. In this regard, RAE decided to order HEnEx S.A. to carry out a feasibility study, as well as to establish a Steering Committee with representatives of RAE, HEnEx and the Ministry, to monitor, on a constant basis, the process for planning and implementing the new natural gas markets. In this way, it is estimated that all RAE approval procedures, as well as any necessary legal provisions, stipulated in Article 91 of Law 4512/2018 shall be accelerated.

Regarding the natural gas retail market, there were some major changes in 2018. Specifically, following the adoption of Law 4336/2015, the monopoly of gas companies in Attica and Thessaloniki / Thessaly were abolished on 01.01.2018. Since then, any gas supply company may be active in the whole gas market with no geographical restrictions and as long as the necessary infrastructure is available. At the same time, with the establishment of the gas distribution companies (EPAs), which now manage the distribution networks, the unbundling of distribution from the supply activity of gas was completed. At the end of 2018, 21 suppliers were active in the natural gas market.

Amendment of the Tariff Regulation of the National Natural Gas System - Regulation (EU) 2017/460. RAE, in 2018, in accordance with the provisions of Regulation 2017/460 on the establishment of a network code on harmonized transmission tariff structures for gas, begun the preparation for the transposition of the above Regulation and held a public consultation on DESFA's proposal for the amendment of the gas Tariff Regulation, according to the provisions of the Articles 26, 27 & 30 of EU Regulation 2017/460. The main goal of the Regulation (EU) 2017/460 is to increase the transparency of transmission tariff structures, setting out specific requirements for publishing the information related to the determination of Allowed Revenue. The final decisions were taken in May 2019 (539/2019 and 566/2019).

Development of Natural Gas Networks

Natural Gas distribution licenses, distribution network operation licenses and Development Plans. Following the unbundling of the distribution and supply activities, according to the provisions of Law 4336/2015, the three new natural gas distribution companies (EDA Attikis, EDA Thessalonikis and DEDA) submitted requests to RAE for the issuance of a natural gas distribution license and a natural gas distribution network operation license. RAE evaluated the applications of the above companies and approved their licenses after the amendment of the Natural Gas Licensing Regulation in 2018. The approved five-year Distribution Development plans (for the period 2018 – 2022) were included in the Decisions No 1314/2018, 1316/2018 and 1318/2018 of RAE that approved the distribution licenses of the three companies.

Regulatory Framework for the Development of Remote Distribution Networks. In 2018 RAE concluded the regulatory framework for the development of the Remote Natural Gas Distribution Networks and the development of Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) supply activities in Remote Natural Gas Distribution Networks and the supply to final customers whose installation is not connected to a transmission system or distribution network, and for the receipt of a Virtual Network Service from the Operator. RAE issued decisions on the "Framework for the development of Remote Distribution Networks using Compressed Natural Gas / Liquefied Natural Gas" and the approval of the auction terms for the Virtual CNG Pipeline by EDA Thessalonikis.

DESFA Certification: In 2014, DESFA S.A. was certified under the unbundling model of Independent Transmission Operator based on RAE Decision No. 523/2014. According to the provisions of paragraph 4 of article 64 of Law 4001/2011, DESFA S.A., in May 2018, informed RAE about a planned transaction regarding the sale of 66% of its shares to a joint venture amongst Snam S.p.A, Enagas Internacional S.L.U. and Fluxys SA. In July 2018, DESFA SA, applied for a new certification under the model of Ownership Unbundling. Following the assessment of the application of DESFA S.A., RAE issued preliminary certification Decision No. 767/2018to certify DESFA S.A. under the model of ownership unbundling. Subsequently, the Authority, taking due account of the opinion of the European Commission and following a thorough analysis, issued its final certification decision 1220/2018 (Government Gazette B '5740 / 19.12.2018). The Decision detailed the compliance framework for DESFA S.A. and any breach of national or EU law or the conditions set under the Ownership Unbundling model would force a revision of it.

Trans-Adriatic Pipeline (TAP) construction is at a mature level of completion and the pipeline is expected to begin its commercial operations in 2020. During 2018, the processes to meet TAP AG's obligations under national and EU law continued. In this context, RAE, in cooperation with the NRAs of Italy and Albania(ARERA and ERE), provided guidance on the issues of TAP Network Code. TAP launched a public consultation on its draft Network Code and then submitted the Code for approval to the NRAs in December 2018, after taking into account the results of the consultation. Within 2018, RAE and the other Regulatory Authorities approved the amendment of the TAP Tariff Code, and the framework for the execution of a new Market Test for additional pipeline capacity under a fully regulated regime. The company has submitted a proposal for approval on how to conduct the bidding process, which would be as far as possible in accordance with both the Final Joint Opinion of the regulators on the TAP expemption and the NC CAM Rules. In addition, in December 2018 the company requested by RAE an amendment of its Independent Natural Gas System license due to changes in the TAP AG's shareholding, as well as a rescheduling for the commercial operation of the pipeline, which had been set for 2020. At the same time, in December 2018, TAP applied for an Independent Natural Gas System Operation License which is currently under evaluation by RAE.

Regarding the Interconnector Greece-Bulgaria (IGB), the Regulatory Authorities of Greece and Bulgaria have worked together from July 2017 to May 2018 to form a Joint Opinion and draft a common text ("Joint Opinion of the Energy Regulators on the Exemption Application of ICGB AD") which contained the necessary terms and conditions for the exemption from the Third-Party access obligations, firstly approved by RAE Decision No 483/2018. RAE and EWRC further cooperated on the amendment of the above opinion in order to comply with the relevant European Commission's opinion, and issued the final Joint Opinion on the exemption of IGB from Third-Party Access rules in August 2018 (RAE Decision No 768/2018).

Security of Supply. The entry into force and the implementation of Regulation (EU) 2017/1938 concerning measures to safeguard security of gas supply and repealing Regulation (EU) 994/2010, have brought significant changes in Competent Authorities' (CA) obligations of each Member State. As of 2018, RAE, CA of Greece for the implementation of Regulation (EU) 2017/1938, updated the Preventive Action Plan (PAP), in accordance with the provisions of Articles 8 and 9 of the Regulation, based on the findings of the National Risk Assessment for the years 2017 – 2020. The Preventive Action Plan includes both new and amended actions related to demand-side management, emergency supply and temporary storage of LNG, emphasizing on an increased readiness degree of the electricity sector in addressing risks / disruptions of natural gas supply. For the development of the study, RAE cooperated with DESFA SA, IPTO, the Ministry of Environment and Energy and the Joint Research Centre (JRC) of the European Commission. For the implementation of the measures included in the PAP and the financing (through the Security of Supply Levy) of the actions RAE, after the approval of the Plan (Decision No 500/2018, Government Gazette B' 2672/06.07.2018 and 3329/10.08.2018), issued three (3) Decisions, i.e. Decision No 1287/2018 (Government Gazette B΄ 5900/31.12.2018) on *"Regulating the Management of the National Gas System for the Implementation of Action D5[2] of the Preventive Action Plan to Ensure Security of Natural Gas Supply"*, Decision No 1211/2018 (Government Gazette B΄ 5891/31.12.2018), which is an amendment of RAE's Decision 344/2014 on *"Determining the Maximum Allowed Limit of Security of Supply Account, Security of Supply Levy per Category of Gas Customer, and Standard Power Unit, in accordance with the provisions of*

[2] Action D5: Use of Revithoussa terminal to maintain seasonal LNG reserves by Electricity Producers. RAE Decision No 1287/2018 was formed based on the relevant recommendation of DESFA, taking also into account the comments of the participants in the public consultation which was conducted by RAE from 06.11.2018 to 16.11.2018, according to the provisions of Law 4001/2011 (paragraph 1 of Articles 29 and 69).

article 73 of Law 4001/2011, as applicable" and Decision No 1299/2018 (Government Gazette B΄ 164/30.01.2019) *"Amendment to the provisions of the System Operation Code (Government Gazette B΄ 103/31.01.2012) of the Greek Electricity Transmission System and the Electricity Transactions Code (Government Gazette B΄ 12310/2018) for the implementation of Action D6*[3] *of the Preventive Action Plan"*.

In Regulation (EU) 2017/1938 emphasis is given on Regional Dimension. In this context, RAE, in 2018, participated in the development of three Common Risk Assessments (CRAs) of all relevant risk factors which could lead to the materialization of the major transnational risk to the security of gas supply to the Ukrainian, the Algerian and the Trans-balkan risk groups, as listed in Annex I of the Regulation[4]. RAE is also the coordinator of the Trans-Balkan CRA, which is currently under development in collaboration with DESFA, IPTO, JRC and the other competent authorities of the Member States of the risk group (Bulgaria and Romania). The CRA for the Algerian risk group has been completed in the end of 2018, while the CRA of the Ukrainian risk group is expected to be completed in the first quarter of 2019.

In addition, RAE, applying the relevant provisions of Regulation (EU) 2017/1938, initiated in 2018 the process of preparing an updated National Risk Assessment with all relevant risks that may affect the security of gas supply – as defined in Article 7 of the Regulation.

Finally, RAE has been closely monitoring the 2nd upgrade of the LNG terminal station at Revithoussa island, a project of great importance for the country for the security of gas supply. In this context, RAE issued Decisions No 257/2018, No 1088A/2018 and No 427/2018 which approved the regulatory framework that was deemed necessary for the support of the upgrade of the terminal.

2.4 Other important actions of RAE

Long-term energy planning. In the context of the country's energy planning, and the preparation of the National Energy and Climate Plan (NECP), RAE participated in all relevant working groups set up for this purpose as well as in the National Energy and Climate Committee. In this framework, It was considered appropriate to carry out a specialized technical study in the transport sector for the period 2020-2030, examining various alternative scenarios for achieving the 14% share of RES in that sector as it is defined in Article 25 of the Renewable Energy Directive (RED II) and taking into account various technical specificities and constraints applicable in the individual subsectors of the sector, as well as the requirements for new infrastructure that will allow using new technologies and / or new fuels. RAE, in the context of its responsibilities under Article 3 (1) of Law 4001/2011, as well as its related obligations under EU law, commissioned the project "Energy Consumption Study in the Sector of Transport until 2030 in the framework of National Energy Planning" to an external consultant. The terms of reference of the Study were prepared by the relevant working groups within the framework of the NECP. The study was completed in December 2018.

The legislative framework concerning the "Services of general interest" charges in nighttime electricity consumption has changed since 1 January 2018 (Government Gazette A 200/22.12.2017), both in terms of the unit charges and the methodology for calculating the charges. The new nighttime consumer charges

[3] Action D6: Introduction of additional rules to the electricity market for connection with the availability of five (5) units with alternative fuel.

[4] According to Annex I of Regulation (EU) 2017/1938, the Ukrainian risk group is composed by Bulgaria, Czech Republic, Germany, Greece, Croatia, Italy, Luxembourg, Hungary, Austria, Poland, Romania, Slovenia and Slovakia, the Algerian risk group by Greece, Spain, France, Croatia, Italy, Malta, Austria, Portugal and Slovenia and the Trans-balkan risk group by Bulgaria, Greece and Romania.

have slightly reduced the burden of the "Services of general interest" to the lower tier, in which the overwhelming majority of consumers belong. Compared to the previous charging scheme, the consumers that had a nighttime consumption of over 1,700kWh had a disproportionate burden due to the introduction of that tiered charge. RAE, following the implementation of the above charging regime, received a large number of complaints from both consumers and various consumer organizations about the "Services of general interest" excessive nighttime charges since most of the consumers fell into the two largest billing tiers. After taking into account the status of the "Services of general interest" account, as well as the income recovered from the nighttime consumption, it provided an opinion to the Minister of Energy (Opinion No 16/2018 on "Reforming the framework of Services of general interest for the nighttime consumption", for the reduction of the "Services of general interest" charges for the nighttime consumption in order to rationalize the charges on the households. Furthermore, RAE has advised that the above charges to have retroactive effect starting as from 1.11.2018 in order to cover the 2018-2019 winter season.

The participation of RAE for the third consecutive year in the Thessaloniki International Fair (TIF) was an important outreach action for RAE. With the assistance of specialized scientists and the guidance of the Board of the Authority, six energy related events – scientific experiments took place. With the message "*We regulate energy markets for the benefit of consumers and the national economy*", RAE highlighted and linked its important and sensitive areas of competence, to both its citizens / consumers and to the users of its services that are active in the field of energy (companies, bodies, technical and scientific chambers, professional organizations, development agencies, SMEs, participants in the electricity and natural gas markets and other stakeholders), presenting its view as the NRA, the issues and major challenges, specificities and structural changes in the energy market, which are also related to the economic, environmental and social performance that falls under the Authority's strategic approach.

The year 2018 was undoubtedly another year of high improvement for the country's energy performance, in a crucial turning point with structural, rapid and drastic changes in the country's energy sector, where the Regulator acted in the best interest of the consumers and the national economy.

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 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 of 24 May 2017 on the draft certification decision 267/2017 of RAE. 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 continued monitoring the correct application by ADMIE of the aforementioned conditions throughout 2018.

3.1.1.2. Distribution System Operator - DEDDIE S.A.

The Hellenic Electricity Distribution System Operator (HEDNO S.A. or DEDDIE S.A.), 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 2018.

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.".

3.1.2. 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 and/or HVDC). The total length of the national transmission system is (11563 km of 150kV + 4739 km of 400kV + 450 km of interconnection lines =) 16.752 km (2018).

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 239,236Km (low and medium voltage).

3.1.3. 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) [5].

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.

[5] 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, as also updated by CEER's Benchmarking Report 6.1 on the Continuity of Electricity and Gas Supply (July 2018).

Regarding the issue of electricity theft on the Distribution Network, the new Code sets forth a more refined general framework to effectively address this 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. Until the full application of the above rules, which was pending due to the necessary adaptations to operator processes and systems, the relevant regulatory framework is provisionally set by RAE decisions 236/2017 (Gov. Gazette B' 1881/30.05.2017) and 237/2017 (Gov. Gazette B' 1946/07.06.2017), as amended by RAE Decisions 1019/2017 and 1020/2017 respectively (Government Gazette B' 4496/20.12.2017).

Distribution loss factors for 2018, as set out in RAE's Decision no.1022/2017, were relatively higher, compared to the factors of 2017. More specifically, the rate was higher by 0.4% for the MV customers and by 1.8% for LV customers. As noted in previous annual reports of RAE, the total amount of lost energy in the Distribution Network is on a constant rise since 2012. The main reason behind this phenomenon, which has alarmed the Distribution System Operator (DEDDIE), is power theft. In 2018, DEDDIE updated the study concerning power losses based on data of 2017 and submitted a proposal to RAE. RAE approved by Decision no.1242/2018 the new power losses factors. The new factors, which are slightly lower than the previous ones (0.2% for MV customers and 0.5% for LV customers), will apply from 1.1.2019.

3.1.4. 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).

3.1.5. Transmission Network operation

Required Revenue and user tariffs:

In 2018, Decision 235/2018 was published, setting TSO's'Allowed Revenue (AR) for the second Regulatory Period, 2018-2021, and TSO's Required Revenue (RR) for 2018. Required Revenue for 2018 was set at 197.5 million euros after considering all parameters included in the Transmission System's RR methodology.

The methodology for setting the TSO's Allowed and Required Revenue dates back to 2014 (Decision no 340/2014). The most critical changes, in comparison with the previous applied methodology (a cost-plus methodology), are:

- A multi-year regulatory 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 TSO's 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 Residential 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-based charge (no energy charge for TUoS) which is 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-based charge for TUoS). For Residential customers (except for Residential customers with Social Tariff), 10% of the allocated cost is recovered through capacity-based 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.

According to 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 (235/2018was taken in the first quarter of 2018. Due to the high degree of uncertainty concerning the demand forecasting for 2018, the charges remained at the same level as they were in 2017. Based upon the above-mentioned methodology, RAE's Decision 235/2018 approved the following Allowed Revenues for 2018-2021 and Required Revenue for 2018 as shown in Table 1 and Table 2 below. Furthermore, Table 3 presents the regulated tariffs applied for the use of the transmission system in 2018.

	2018	2019	2020	2021
OPEX	77.269.000	77.862.000	78.461.000	79.066.000
Annual Depreciation	55.203.000	58.335.000	76.370.000	77.063.000
Regulatory Asset Base (RAB)	1.449.808.000	1.684.495.000	1.941.335.000	2.059.771.000
WACC	7,0%	6,9%	6,5%	6,3%
Allowed Return	**101.487.000**	**116.230.000**	**126.187.000**	**129.766.000**
Allowed Revenue (AR)	**233.959.000**	**252.427.000**	**281.018.000**	**285.895.000**

Table 1: Allowed Revenue of Transmission System 2018 -2021 (amounts in €)

(AR) Allowed Revenue of Transmission System	233.959.000
Cost of investments financed by third parties	7.163.738
Under/Over Recovery	7.580.576
Adjustments due to over/under investment (depreciation and allowed return) of previous years	-7.646.401
Revenues from Interconnection Capacity Rights	-35.383.112
Inter-Transmission System Operator Compensation mechanism (ITC)	776.236
Revenues from Non-Regulatory Activities	-8.939.000
(RR) Required Revenue of Transmission System 2018	197.511.038

Table 2: Required Revenue of National Transmission System 2018.(amounts in €)

Consumers Category	Capacity charge	Energy charge (cents €/ kWh)
Large Consumers HV	24,103 €/MW /per year	-
Consumers MV	1,329 €/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

Table 3: Regulated Tariffs applied for the use of the transmission system in 2018

3.1.6. Distribution Network operation

Required Revenue and user tariffs:

Regarding the Required Revenue for the Distribution Network, until the methodology of Required Revenue that is mentioned in the Distribution Network Code is fully applicable, the previous methodology, prescribed in RAE's Decision 840/2012, remains in force.

For 2018, RAE processed the Distribution System Operator's proposal for setting the Allowed and the Required Revenue of Distribution Network for the year 2018 and published Decision 545/2018 setting the Allowed Revenue at 743.6 million euros (2017: 753.7 million euros) and the Required Revenue at 752.8 million euros (2017: 741.7 million euros). The determination of the Allowed Revenue for 2019, was set by Decision 572/2019.

Regarding revenue regulation, the Distribution Network Code 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.

Due to the high degree of uncertainty concerning the demand forecasting for 2018, the charges remained at the same level as they were in 2017.

Based upon the above-mentioned classification, RAE's Decision Ref no 455/2016 approved the tariffs for 2017, which remained unaltered during the year 2018 (see Table 4):

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 €/kVA 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

Table 4: Regulated tariffs applied for the use of the distribution system in 2018

3.1.7. 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.

3.1.8. 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.

3.1.9. Cross-border issues

In 2018, import trading schedules increased considerably (+23.6%) reaching a total of 11,224 GWh. After calculating the amount of power imported by Albania, North Macedonia, Bulgaria and Turkey (64.39%, 42.13%, 21.76% 43.01% respectively), the increase ranged from 22% to 64% while the imports from Italy dropped by 21.09%.

Also export trading schedules' rise amounted to +74.73% reaching 4,983 GWh and continuing its already rising trend. Italy represents 42.84% of export trading schedules (increase by 179.04%), North Macedonia represents 31.96% (increase by 71.46%), Albania represents 20.25% (increase by 20.25%) and finally Turkey drawing an increase of 31.86%. Bulgaria noted a drop both in terms of share of export trading schedule (4.51% compared to 9.38 in 2017) and in absolute terms (-15.96%).

Interconnections	Transmission lines power (KV)	Transmission Power Capacity (MW)	Transmission Trading Capacity (real) MW*.
Greece - Bulgaria	1 line 400 KV	500 - 600MW	500MW
Greece – North Macedonia	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)			

Table 5: Greece's cross border interconnections transmission capacity in 2018

Description	Turkey	Albania	North Macedonia	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)	21.744	1.008.863	1.592.472	224.866	2.134.658	4,982,603
Imported Energy (GWh)	734.754	1.986.414	2.977.555	3.896.681	1.628.257	11,223,661

Table 6: Interconnection power capacity and scheduled trade in 2018

Table 7 presents the monthly performance of the import interconnection trading in years 2018, 2017 and 2016 and Table 8 presents the import share of cross - border allocation of the interconnection trading in 2018 and its performance compared to the years 2017 and 2016.

	2016	2017	2018
January	1,248,828	348,376	1.030.381
February	951,577	625,873	834.638
March	1,249,082	1,040,800	818.854
April	1,042,495	1,001,664	975.046
May	990,553	830,233	829.034
June	983,489	750,881	886.421
July	939,518	941,112	1.264.253
August	1,003,102	761,562	932.106
September	928,903	909,413	843.305
October	724,582	540,553	803.520
November	586,631	509,023	894.569
December	714,818	821,315	1.111.534
Total	**11,363,578**	**9,080,805**	**11.223.661**

Table 7: Total import interconnection trading (MWh), 2016 - 2017 - 2018

Import share									
Turkey		**Albania**		**North Macedonia**		**Bulgaria**		**Italy**	
2017	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**	**2018**
5.66%	6,55%	13.31%	17,70%	23.07%	26,53%	35.24%	34,72%	22.72%	14,51%

Table 8: Cross border allocation of interconnection trading (2017-2018)

	2016	2017	2018
January	161,563	281.129	227.453
February	44,971	263.471	267.891
March	58,222	120.310	413.479
April	99,082	157.805	287.184
May	92,375	179.804	259.722
June	117,328	176.935	314.872
July	229,501	249.908	390.833
August	206,166	376.668	523.430
September	237,229	253.092	496.642
October	408,292	285.488	600.405
November	210,395	217.167	565.234
December	339,198	289.771	635.458
Total	**2,204,322**	**2.851.548**	**4.982.603**

Table 9: Total export interconnection trading (MWh), 2016 - 2017 - 2018

Turkey		Albania		North Macedonia		Bulgaria		Italy	
2017	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**	**2018**
0.58%	0,44%	30.64%	20,25%	32.57%	31,96%	9.38%	4,51%	26.82%	42,84%

Table 10: Energy Export share per country (2017-2018)

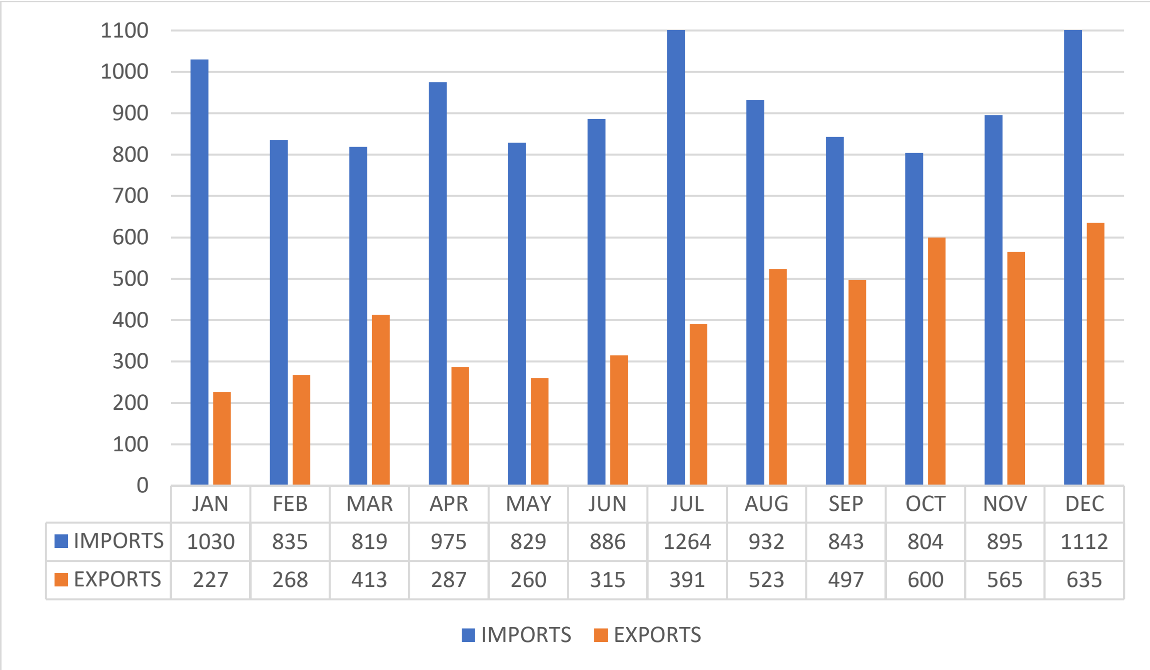


Figure 1: Cross-Border Electricity Trading in 2018

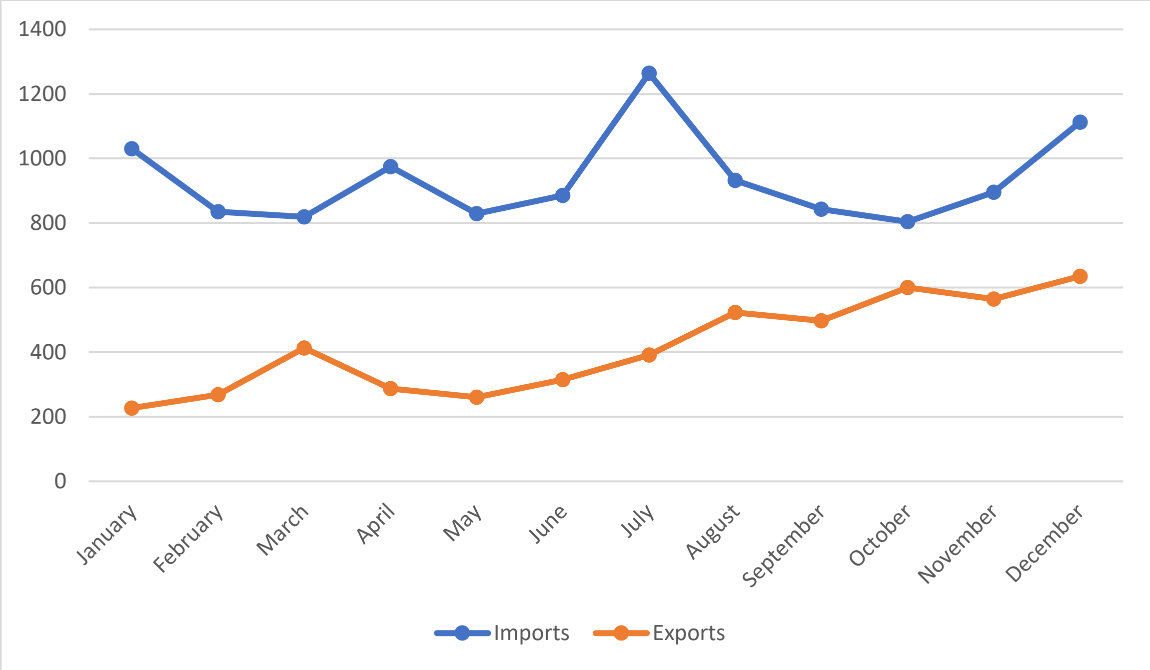


Figure 2: Electricity Imports and Exports 2018

The physicals flows for the year 2018 amounted to:

- Greece imported from Albania 1,061 GWh while exported 918 GWh to Albania.
- Greece imported from Bulgaria 2,120 GWh while exported 7 GWh to Bulgaria.
- Greece imported from Italy 611 GWh while exported 1,076 GWh to Italy.
- Greece imported from North Macedonia 1,853 GWh while exported 254 GWh to North Macedonia. Greece imported from Turkey 2,908 GWh while exported 10 GWh to Turkey.

Regarding the Italy-Greece border, during 2018 a severe malfunction of the underwater cable between Greece and Italy (from 3 September to 30 November 2018) resulted in the suspension of the monthly auctions from October to December whereas the 2019 annual auction was conducted with reduced capacity. Those users holding long-term rights from the 2018 annual action were reimbursed according to the price of the original auction since the outage limit of 45 days was reached on 6 October 2018 and hence from 7 October onwards their rights were guaranteed.

With Decision 954/2017, RAE also 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. In 2018, new rules for the long-term (annual and monthly) physical transmission rights applied 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 were conducted only explicitly according to «Rules for explicit Daily Capacity Allocation on Bidding Zone borders services by SEE CAO v1.0».

At Greece – Bulgaria border, Common Transmission Capacity Allocation Rights' Rules have been 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.

In this framework, RAE adopted in 2018 the following Decisions related to auctions for the contracting of access rights to the interconnections of the Greek transmission system with the neighboring countries for cross-border electricity trading:

1. Decision No 1307/2018 for the approval of Auctioning Regulation on the contracting of intraday capacity at the Greece- Bulgaria interconnection for the year 2019 (Gazette B’ 5911/31.12.2018).

2. Decision No 1309/2018 for the approval of Auctioning Regulation of Joint Allocation Office (JAO) about the contracting of intraday capacity at the Greece – Italy interconnection for the year 2019 (Gazette B’ 5912/31.12.2018).

3. Decision No 1308/2018 for the approval of Auctioning Regulations for the access rights contracting of South East Europe Coordinated Auction Office (SEE CAO) at the northern interconnections of Greek Transmission System with Albania, North Macedonia and Turkey for the year 2019 (Gazette B’ 5921/31.12.2018).

2. Implementation of European Network Codes and Guidelines:

(A) In 2018, RAE, within the framework of Regulation (EU) 2015/1222 concerning capacity allocation guidelines and congestion management CACM, published the following Decisions

1. Decision No. 93/2018 concerning the approval of NEMOs’ proposal for the products which could be included in the single day-ahead coupling, according to the article 40 paragraph 1 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B’ 485/16.2.2018).

2. Decision No. 94/2018 concerning the approval of NEMOs’ proposal for the products which could be included in the single intraday coupling, according to the article 53 paragraph 1 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B’ 397/9.2.2018).

3. Decision No. 95/2018 concerning the approval of NEMOs’ proposal for Back-up Methodology according to Article 36 paragraph 3 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B’ 398/9.2.2018).

4. Decision No. 124/2018 concerning submission request towards ACER for the Decision publication of NEMOs’ proposal about price coupling algorithm and continuous trading matching algorithm, according to Article 35 paragraph 5 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B’ 489/9.2.2018).

5. Decision No. 201/2018 concerning submission request towards ACER, according to Article 8 paragraph 1 of (EC) 713/2009 of 13 July 2009 by European Parliament and the Council for the extension of decision-making deadline of NRAs concerning intraday capacity tariffs, according to Article 55 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B’ 956/19.3.2018).

6. Decision No. 244/2018 concerning the decision making on the TSOs’ proposal amendment of Greece – Italy capacity calculation region (CCR GRIT) for the methodology of coordinated capacity calculation within the relevant region, according to Articles 20 and 21 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B’ 1162/29.3.2018).

7. Decision No. 317/2018 concerning the approval of NEMOs’ and TSOs’ of Italy, Slovenia, Austria, France, Greece and Switzerland proposal on the regional cost allocation in the intraday market at Italian borders, according to Article 80 paragraph 4 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B’ 1533/4.5.2018).

8. Decision No. 319/2018 concerning the approval of TSOs’ proposal on Southeastern European capacity allocation calculation (SEE CCR) for the setting of fallback procedures, according to Article 44 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B’ 1558/8.5.2018).

9. Decision No. 492/2018 concerning the decision-making about CCR GRIT NEMOs’ and TSOs’ amendment of their proposal concerning the planning and implementation of supplementary intraday regional auctions, according to Article 63 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B’ 2510/29.6.2018).

10. Decision No. 497/2018 concerning the decision-making about TSOs’ proposal amendment of the SEE CCR for the methodology of coordinated capacity calculation within the relevant region, according to Article 20 and 21 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B’ 2671/6.7.2018).

11. Decision No. 653/2018 concerning the approval of CCR GRIT TSOs’ proposal for the methodology of coordinated capacity calculation within the relevant region, according to Article 20 and 21 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B’ 3649/27.8.2018).

12. Decision No. 738/2018 concerning the decision-making for request submission to ACER for Decision publication of intraday capacity tariffs methodology, according to Article 55 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B’ 4223/27.9.2018).

13. Decision No. 831/2018 concerning the decision-making on the amendment of TSOs’ common proposal about scheduled exchanges’ calculation methodology resulting from the single day-ahead coupling, according to Article 43 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B’ 4402/3.10.2018).

14. Decision No. 832/2018 concerning the decision-making on the amendment of TSOs’ common proposal about scheduled exchanges’ calculation methodology resulting from the single intraday coupling, according to Article 56 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B’ 4444/8.10.2018).

15. Decision No. 833/2018 concerning the decision-making on the amendment of CCR GRIT TSOs’ proposal for the coordinated redistribution and counterbalancing transaction methodology, according to Article 35 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B’ 4444/8.10.2018).

16. Decision No. 834/2018 concerning the approval of CCR GRIT TSOs' proposal on redistribution cost allocation and counterbalancing transaction methodology, according to Article 74 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B' 4403/3.10.2018).

17. Decision No. 1042/2018 concerning the decision-making on the amendment of SEE CCR TSOs' proposal for the coordinated capacity calculation methodology within the relevant region, according to Article 20 and 21 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B' 5058/13.11.2018).

18. Decision No. 1057/2018 concerning the decision-making on the amendment of SEE CCR TSOs' proposal for the coordinated redistribution and counterbalancing transaction methodology, according to Article 35 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B' 5332/28.11.2018).

19. Decision No. 1124/2018 concerning the decision-making for request submission to ACER for Decision publication on TSOs' single proposal of Capacity Calculation Regions, according to Article 15 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B' 5450/5.12.2018).

20. Decision No. 1179/2018 concerning the decision-making of CCR GRIT NEMOs' and TSOs' proposal for the planning and implementation of supplementary regional intraday auctions, according to Article 63 of Regulation (EU) 2015/1222 of 24 July 2015, about establishing a guideline on capacity allocation and congestion management (Gazette B' 5595/12.12.2018).

(B) In 2018, RAE, within the framework of Regulation (EU) 2016/1719 concerning the establishing a guideline on forward capacity allocation, published the following Decisions

1. Decision No. 208/2018 concerning the decision-making on the amendment of TSOs' single proposal for the common long-term network model methodology, according to Article 18 of Regulation (EU) 2016/1719 of 26 September 2016, concerning the establishing a guideline on forward capacity allocation (Gazette B' 747/5.3.2018).

2. Decision No. 318/2018 concerning the decision-making on the amendment of TSOs' single proposal for the bidding zone border Italy BRNN-Greece for setting physical transmission rights rules, according to Article 36 of Regulation (EU) 2016/1719 of 26 September 2016, concerning the establishing a guideline on forward capacity allocation (Gazette B' 1533/4.5.2018).

3. Decision No. 320/2018 concerning the approval of SEE CCR TSOs' common proposal for the long-term transmission rights planning which will be published for every bidding zone border within the relevant region, according to Article 36 of Regulation (EU) 2016/1719 of 26 September 2016, concerning the establishing a guideline on forward capacity allocation (Gazette B' 1558/8.5.2018).

4. Decision No. 373/2018 concerning the decision-making for Greece-Bulgaria TSOs' common proposal amendment on setting physical transmission rights rules, according to Article 36 of Regulation (EU) 2016/1719 of 26 September 2016, concerning the establishing a guideline on forward capacity allocation (Gazette B' 1877/24.5.2018).

5. Decision No. 620/2018 concerning the approval of TSOs' common proposal for the common long-term network model methodology, according to Article 18 of Regulation (EU) 2016/1719 of 26 September 2016, concerning the establishing a guideline on forward capacity allocation (Gazette B' 3064/27.7.2018).

6. Decision No. 654/2018 concerning the approval of Italy BRNN – Greece bidding zone border TSOs on the setting of physical transmission rights rules, according to Article 36 of Regulation (EU) 2016/1719 of 26 September 2016, concerning the establishing a guideline on forward capacity allocation (Gazette B' 3591/23.8.2018).

7. Decision No. 739/2018 concerning the approval of Greece-Bulgaria TSOs' common proposal on setting physical transmission rights rules, according to Article 36 of Regulation (EU) 2016/1719 of 26 September 2016, concerning the establishing a guideline on forward capacity allocation (Gazette B' 3378/10.8.2018).

8. Decision No. 1180/2018 concerning the decision-making for the approval of common CCR GRIT TSOs' proposal on regional requirements of Coordinated Allocation Rules, according to Articles 51 paragraph 3 and 52 of Regulation (EU) 2016/1719 of 26 September 2016, concerning the establishing a guideline on forward capacity allocation (Gazette B' 6205/31.12.2018).

9. Decision No. 1180/2018 concerning the decision-making for the amendment of TSOs' proposal about Congestion Income Distribution Methodology (CIDM), according to Article 57 of Regulation (EU) 2016/1719 of 26 September 2016, concerning the establishing a guideline on forward capacity allocation (Gazette B' 6049/31.12.2018).

(C) In 2018, RAE, within the framework of Regulation (EU) 2017/2195 concerning the establishing of a guideline on electricity balancing, published the following Decisions

1. Decision No. 1141/2018 concerning the decision-making on the amendment of TSOs' proposal for the implementation framework of European Platform on the imbalance calculation procedure, according to Article 22 of Regulation (EU) 2017/2195 of 23 November 2018, concerning the establishing of a guideline on electricity balancing (Gazette B' 5360/29.11.2018).

3. Monitoring TSO investment plans and PCIs

In 2018, with RAE's Decision n. 256/2018 pursuant to the procedure of Art. 108 of Law 4001/2011 the NDP of the period 2018-2027 was adopted. RAE, within the framework of TYNDP, requested from ADMIE S.A. the following:

- Phase 1 of Crete-Peloponnese interconnection should be constructed according to the Greek TSO plan, by installing underground cables and decreasing the environmental footprint as much as possible by means of appropriate applicable measures (i.e. use of underground cables). This project is meant to be completed by the first half of 2020.
- ADMIE S.A. and Euroasia Interconnector Ltd should finalize the shareholders agreement and implement Phase 2 of the Crete-Attica interconnection as soon as possible. Transmission capacity of the cable will be 1000MW.
- A binding schedule to be set for the completion of Cyclades interconnection Phase 2 in the second half of 2019 and of Phase 3 in the second half of 2020. Phase 1 of the project became operational in March 2018.

- ADMIE S.A. should submit to RAE a progress report on the islands' interconnections every two months, including what tasks have been done and their outcome and what actions will be taken in order to realize the projects on time.
- ADMIE S.A. and DEDDIE S.A. should cooperate and make a common proposal about Phase 4 of the Cyclades interconnection. Based on the committee examining the efficiency of non-interconnected islands' electrification, the project should be included in the next TYNDP 2019-2028.

In July 2018, ADMIE S.A. resubmitted the updated draft of TYNDP 2019-2028 to RAE for approval. The updates concerned the interconnection Crete-Attica (Phases 1 and 2).

Monitoring of 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 was submitted to relevant NRAs (RAE and CERA). 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's request evaluation process and, as RAE had informed the requested body, additional data had to be submitted. 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 requests should be completed within six (6) months of the 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).

Regarding this project, in 2018, RAE, as the competent authority and with the view to ensuring, primarily, Crete's security of supply by virtue of Regulation (EU) no. 347/2013, Directive 2009/72/EC, as transposed into the Greek legal order by Law no. 4001/2011, and Decision 2014/536/EU of the European Commission, issued decisions no. 816/2018, 838/2018, 1190/2018 and 150/2019. Pursuant to the above decisions, a special purpose vehicle (SPV) with the company name "Crete-Attica Electrical Interconnection Ariadne Special Purpose Limited Company" and the registered title "ARIADNE INTERCONNECTION S.P.L.C." would be incorporated and appointed, in full accordance with the provisions of the relevant CBCA and in line with the TEN-E Regulation, as the party financing and constructing the Attica-Crete interconnection (stage 1 of PCI 3.10.3).

Additionally, according to the European Regulation 347/2013, ADMIE S.A. (Greek TSO) and ESO-EAD (Bulgarian TSO) submitted an Investment Request to their corresponding Regulators (RAE and EWRC) for the Project of Common Interest (PCI) 3.7.1 "New interconnection transmission line Nea Santa (Greece) – Maritsa East 1 (Bulgaria)". In May 2018, the two NRAs considered the file of the project as complete and the relevant CBCA Decision was issued in August 2018.

This project is indivisible part of the wider PCI (cluster) 3.7 unit which includes another 3 HV lines inside the Bulgarian territory. The proposed project (3.7.1) would constitute the second Greece-Bulgaria interconnection after the interconnection of Thessaloniki with Blagoevgrad.

3.2 Promoting Competition

3.2.1. Wholesale market

3.2.1.1. Description of the wholesale market

The Ministry of Environment and Energy, in collaboration with other competent authorities, drew up a bill for the Energy Exchange, which was set for public consultation from 01.12.2017 to 11.12.2017. The Greek Parliament voted in favor of the creation of an Energy Exchange (Law 4512/2018) in 15.01.2018 (Gazette A΄ 5/17.01.2018) which amended Laws 4425/2016 and 4001/2011.

According to Law 4512/2018, there is the provision for the creation of "Hellenic Energy Exchange S.A." by LAGIE's split-off while the latter is renamed as DAPEEP S.A. The term "Energy Exchange" is introduced as a Société Anonyme (S.A.) which operates multiple energy markets. Some of the Electricity Markets are the following: Day-Ahead, Intraday and Balancing which operate as wholesale energy product markets, according to Regulation (EU) 1227/2011. The term of Forward Electricity Wholesale Products, as defined by Law 4425/2016, is now abolished and are traded in the Financial Energy Market.

In the Day-Ahead Market, transaction orders for supply and demand will be submitted per unit in the case of Producers and per Bidding Zone or Border in the case of other Market Participants. The transaction orders for RES injection and for the aggregators can be submitted per portfolio of every technology and category of RES unit and per load zone. Aggregators submit different orders for supply and demand. Producers are obliged to submit orders for supply for the total amount of their units' capacity which has not been bound through Financial Energy Markets or bilaterally out of this Market with a commitment of physical delivery.

For the participation in the Intraday Market, the Participants submit their transaction orders per unit and other Market Participants submit their orders per Bidding Zone or Border. The transaction orders for RES injection and for the aggregators can be submitted per portfolio of every technology and category of RES unit and per load zone. The aggregators submit different orders for supply and demand.

The Balancing Market is based on the principle of the central scheduling and allocation (central allocation), where scheduling is happening, and the Allocation Orders are published per unit (unit based central dispatching model). Within that framework, Integrated Scheduling Process is realized which constitutes a balancing energy and a balancing capacity, according to Article 5 of Law 4425/2016[6].

Until the full implementation of the above system, the Greek wholesale electricity market will continue to be based on a pure day ahead mandatory pool mechanism. Day-ahead scheduling model consist the current model for the organization and operation of the national wholesale market through which the total amount of electricity generated and consumed the next day is traded. Generators, auto-producers and importers must declare an offer price for each hour of the following day D for their available capacity to supply

[6] RAE in 2018 adopted the following regulatory Decisions pertaining to necessary technical arrangements for the proper functioning of the electricity wholesale market: Decision 508/2018 (Gazette B΄ 2310/18.06.2018), Decision 509/2018 (Gazette B΄ 2307/18.06.2018), Decision 511/2018 (Gazette B΄ 2309/18.06.2018), Decision 780/2018 (Gazette B'3974/13.09.2018), Decision 1299/2018 (Gazette B'164/30.01.2019) , Decision 1322/2018 (Gazette B' 6185/31.12.2018), Decision 294/2018 (Gazette B΄1474/27.04.2018), Decision 405/2018 (Gazette B'4547/18.10.2018), Decision 931/2018 (Gazette B' 5794/21.12.2018), Decision 1003/2018 (Gazette B'6066/31.12.2018), Decision 1041/2018 (Gazette B'5094/15.11.2018), Decision 1231/2018 (Gazette B'5918/31.12.2018), RAE's Decision 1249/2018 (Gazette B'5958/31.12.2018), Decision 1322/2018 (Gazette B'6185/31.12.2018)

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[7].

[7] 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.

3.2.1.2. Installed Capacity and Generation

In 2018, the installed capacity in the interconnected system of Greece was slightly increased (17,443 MW) compared to 2017 (17,196 MW). Notwithstanding the increase of RES units' installed capacity which was 5,138 MW in 2017 and amounted to 5,468 MW in 2018. In terms of capacity share (excluding RES), PPC company holds 74.2% compared to 78.7% in 2017, whereas the market share of PPC's conventional units including RES amounts to 50.9% compared to 55.2% in 2017.

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

Installed capacity and production by fuel, in 2018	Installed capacity (MW)	Total annual production (TWh)	Share in produced volume, including RES (%)
Lignite	3,900	14.91	33%
Hydro	3,170	5.05	11%
Natural gas	4,900	14.13	31%
Total Thermal + Large Hydro (1)	11,970	34.09	75%
Total RES (Grid + Network) (2)	5,470	11.11	25%
Total (1+2)	17,440	45.20	100%

Table 11: Installed Capacity and Production by fuel, including RES, in the Interconnected System in 2018

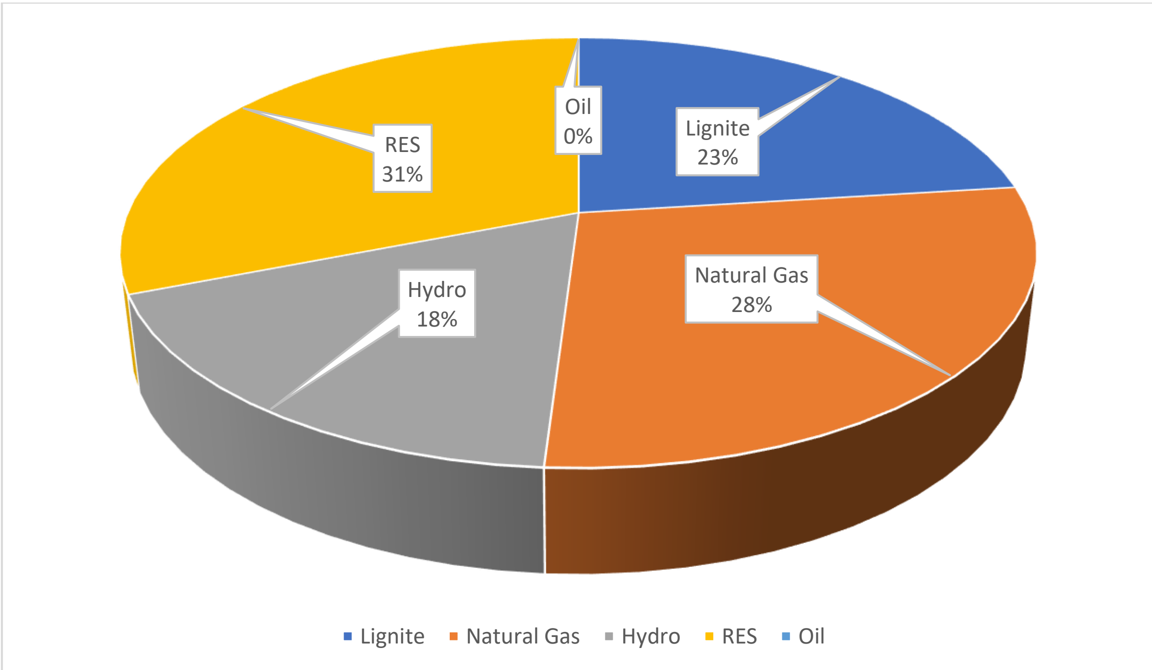


Figure 3: Installed (net) capacity (MW and as a percentage of total capacity) per technology in 2018

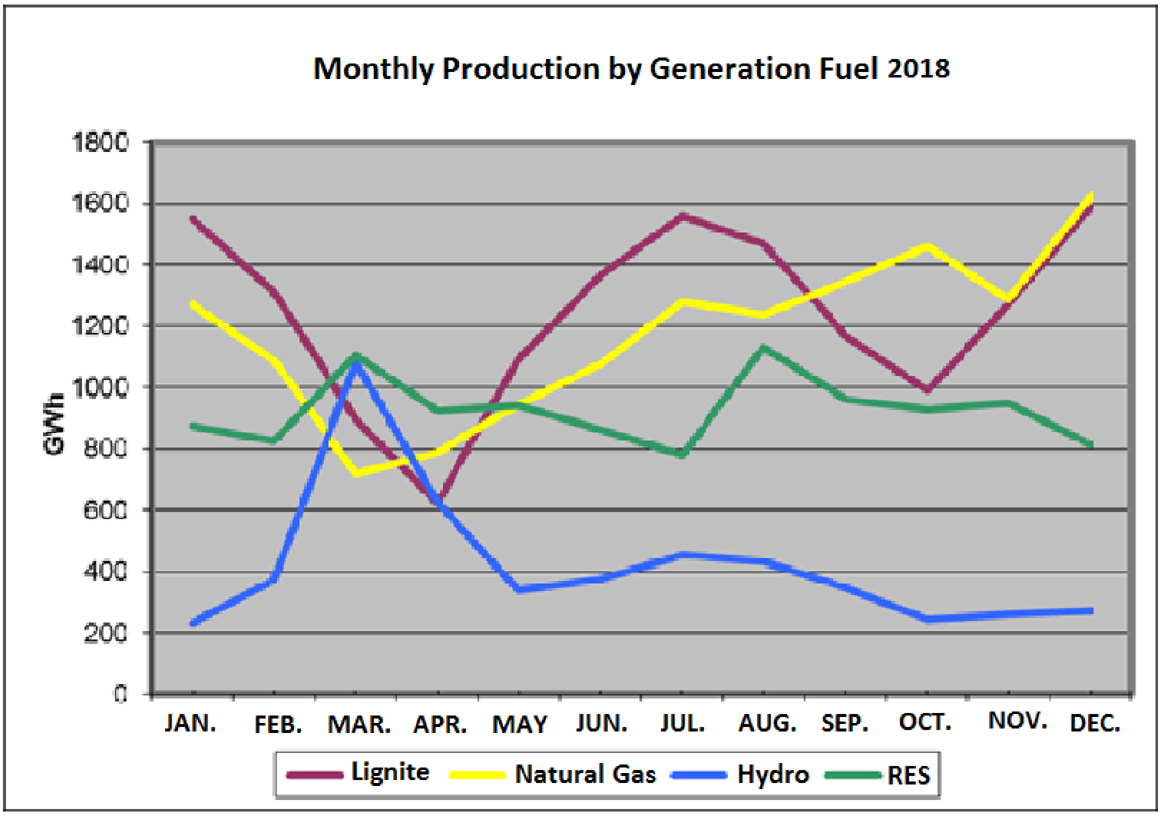


Figure 4: Monthly Production by Generation Fuel in 2018

Lignite production showed a sharp fluctuation between 626 and 1,594 GWh on a monthly basis. April was the month with the lowest demand for lignite-based power while December was the month with the highest demand for 2018. Electricity generation from natural gas followed a decline in April but then recovered fluctuating between 719 and 1,628 GWh. Hydroelectric generation increased considerably compared to 2017 varying between 231 and 1,083 GWh. March was a month with massive rainfalls and combined with the melted snow resulted to a massive volume of water in PPC's hydro reservoirs. RES production varied between 781 and 1,132 GWh minimizing the levels of fluctuation compared to 2017. However, energy production from renewable sources was increased compared to the previous year.

3.2.1.3. Auxiliary and Generation capacity reserves mechanisms (market)

In 2018, the European Commission approved the New Transitory electricity Flexibility Remuneration Mechanism (2018) 4947 final/30.7.2018 in State aid case "SA 50152" for Greece) with a maximum implementation period until December 2019, or until the implementation of the Long-Term Capacity Remuneration Mechanism, if the latter occurs earlier. The New Transitory Electricity Flexibility Remuneration Mechanism (TFRM) was transposed into the Greek legislation with law 4559/2018.

Considering the forthcoming Target Model, the implementation period of the above mechanism is divided in two periods, with at least two separate auctions. The first implementation phase covers the period starting from 3 August 2018 until 31 March 2019 and the second, which may run in parallel with the Target Model, shall cover the period from April 2019 to December 2019. For the period running from April 2019 onwards, an ex-post claw-back mechanism will be established in order to avoid any risk of overcompensation with the Target Model in place. This new mechanism, given its transitory nature, resembles the basic parameters of its predecessor TFRM (implemented in 2016). However, an essential difference is the introduction of a competitive tendering procedure for the determination of the compensation in the current one.

In this context, in 2018 and after considering the comments of the participants in the relevant consultation, RAE issued Decision 780/2018 for the amendment of the provisions of ADMIE Network Code (Government Gazette B103 / 31.01.2012) for the implementation of the new Transitory electricity Flexibility Remuneration Mechanism (Government Gazette B3974 / 13.09.2018).

It is noted that the maximum approved cost of the mechanism for one year is approximately € 175.5 million (maximum auctioned price multiplied by the amount of auctioned power). The actual cost of the mechanism depends on the results of the auctions combined with the application of “claw-back” mechanism from 1st April 2019 onwards.

Furthermore, during 2018 RAE updated the parameters of the Permanent Capacity Remuneration Mechanism, which was renamed as “Long Term Capacity Remuneration Mechanism”, based also on the Adequacy Study of the System 2019 – 2030, submitted by the TSO. Its aim is to contribute to the credibility of the System, to the security of supply as well as the protection of consumers from price spikes. The proposed mechanism is compatible with the planned wholesale market design under the Target Model. Its responsibility is to give the necessary signals for investment as well as to set the frame for a gradual and predefined, timewise, withdrawal of lignite units. According to the proposed scheme the allocation of capacity premiums will be based on a competitive procedure that aims at avoiding of windfall profits.

Furthermore, in 2018, RAE by Decision No. 405/2018 (Gazette B’4547/18.10.2018) set the Administrative Defined Maximum Offer Price at 50€ / MWh for the provision of services of Primary and Secondary Reserve for the offers from 1 October 2018 onwards.

3.2.1.4. Market Settlement

According to ADMIE’s data, based on the metered consumption level at the interconnection point between the transmission and the distribution systems, demand decreased by 1% compared to 2017 (wherein there was an increase by 1.6% compared to 2016). In 2018, the consumption of HV continued its uprising trend for the fourth consecutive year (+1.13%) compared to 2017. The peak demand occurred in July (656 GWh) and was greater than that of 2017 (646 GWh).

On the other hand, a decrease was observed in the Distribution Network showing a reduction of 1.6% compared to 2017, while in 2017 an equal increased had occurred (+1.6%) compared to 2016. Specially in January 2018 there was a decrease in demand of -11.4% compared to 2017 due to different weather conditions. On the contrary, in December 2018 the demand increased by 5.9% compared to 2017 (wherein a drop of 8.7% had taken place compared to 2016).

In Table 12, the monthly imbalances of demand are highlighted. The demand in the interconnected system for 2018 was decreased by 0.91% compared to 2017, and more precisely it dropped at 51.46 TWh compared to 51.93 TWh of 2017 (and 51,21 TWh in 2016).

The real consumption was significantly decreased especially in January 2018 compared to January 2017 (-9.16%) and in August 2018 compared to August 2017 (-3.5%). A worth noting increase happened in December 2018 compared to December 2017 (+4.59%).

3.2.1.5. Market Size

Peak demand occurred in July 2018 (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 17.07.2018, the 14th hour of allocation, with 9,062 MW, compared with 9,674 MW in July 2017. However, it is worth noting that high demand was recorded also in December 2018, reaching 8,698 MW.

It is noteworthy that the real consumption for the period of January – February 2018 was relatively lower (8,889 GWh) than in the same months of 2017 (9,414 GWh). From March until July 2018 the real consumption was almost the same (20,962 GWh) with those of 2017 (21,048 GWh). In August, the consumption was slightly decreased but from September to November the trends of 2018 (12,137 GWh) and 2017 (12,036 GWh) almost coincided. Finally, In December 2018, there was a significant rise (4,784 GWh) when compared to 2017 (4,574 GWh). This rise is mainly due to the colder days of December 2018 compared to 2017.

In 2018, the consumption of High Voltage customers drew a sharp fluctuation with constant increases and decreases. More specifically, in the first (1,850 GWh in 2018 and 1,761 GWh in 2017) and in the third (1,857 GWh in 2018 and 1,784 GWh in 2017) quarter of 2018, the HV consumption was increased compared to 2017. However, in the second (1,839 GWh in 2018 and 1,871 GWh in 2017) and in the fourth (1,805 GWh in 2018 and 1,853 GWh in 2017) quarter the HV consumption was relatively decreased compared to 2017.

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.

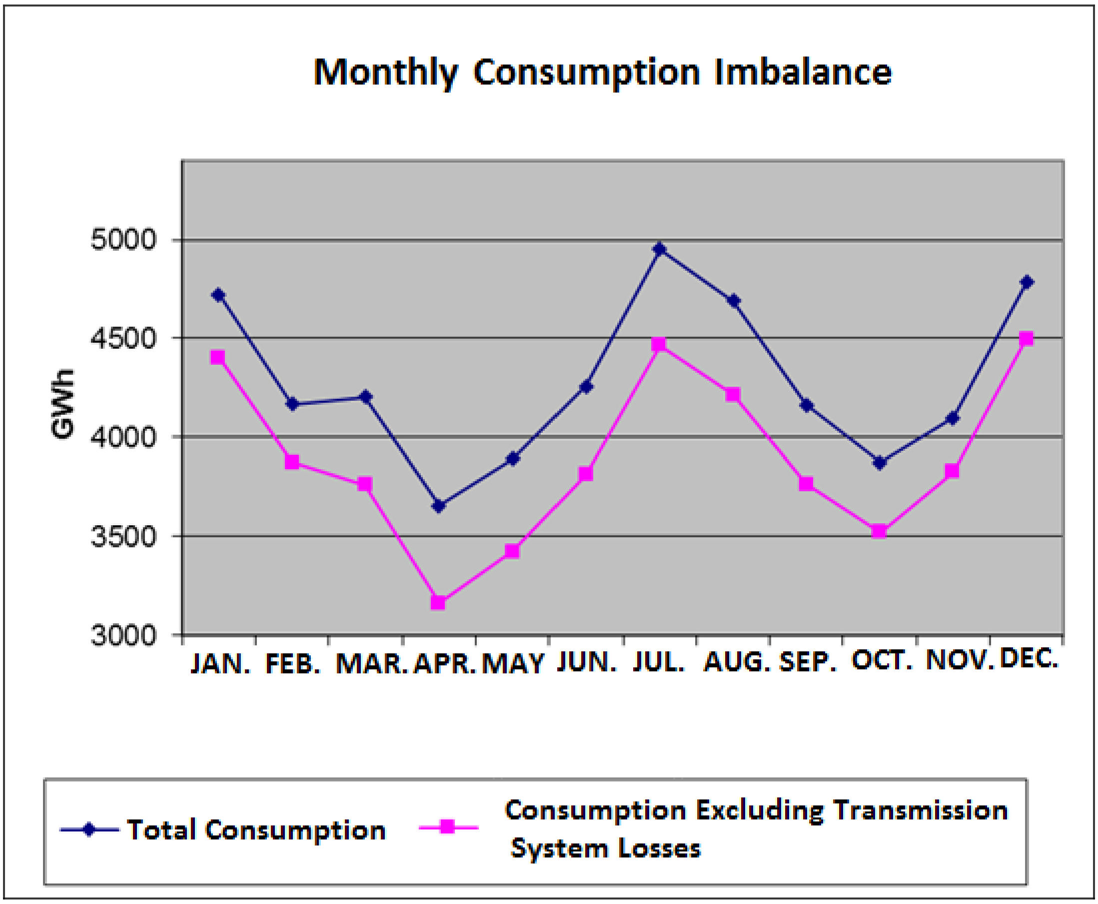


Figure 5: Monthly Electricity Demand in 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Real Consumption (GWh), in 2018	4,722	4,167	4,203	3,657	3,894	4,257	4,951	4,690	4,164	3,874	4,099	4,784	51,462
Consumption at the Grid level (GWh), in 2018	4,404	3,873	3,762	3,165	3,426	3,812	4,464	4,214	3,764	3,522	3,826	4,497	46,729
Real Consumption in 2017 (GWh)	5,198	4,216	4,192	3,719	3,869	4,223	5,045	4,860	4,066	3,835	4,135	4,574	51,932
Difference between real consumption in (2018-2017) (GWh)	-476	-49	11	-62	25	34	-94	-170	98	39	-36	210	-470
% change in real consumption (2018-2017)	-9.2%	-1.1%	0.3%	-1.70%	0.64%	0.80%	-1.90%	-3.5%	2.35%	1.01%	-0.88%	4.6%	-0.72%
Source: December 2018 Monthly Report TSO ADMIE													

Table 12: Monthly Electricity Demand in the Interconnected System (2017-2018)

3.2.1.6. Monitoring market shares

More in detail, the installed capacity during 2018 was divided per technology and production companies as shown in the figures below:

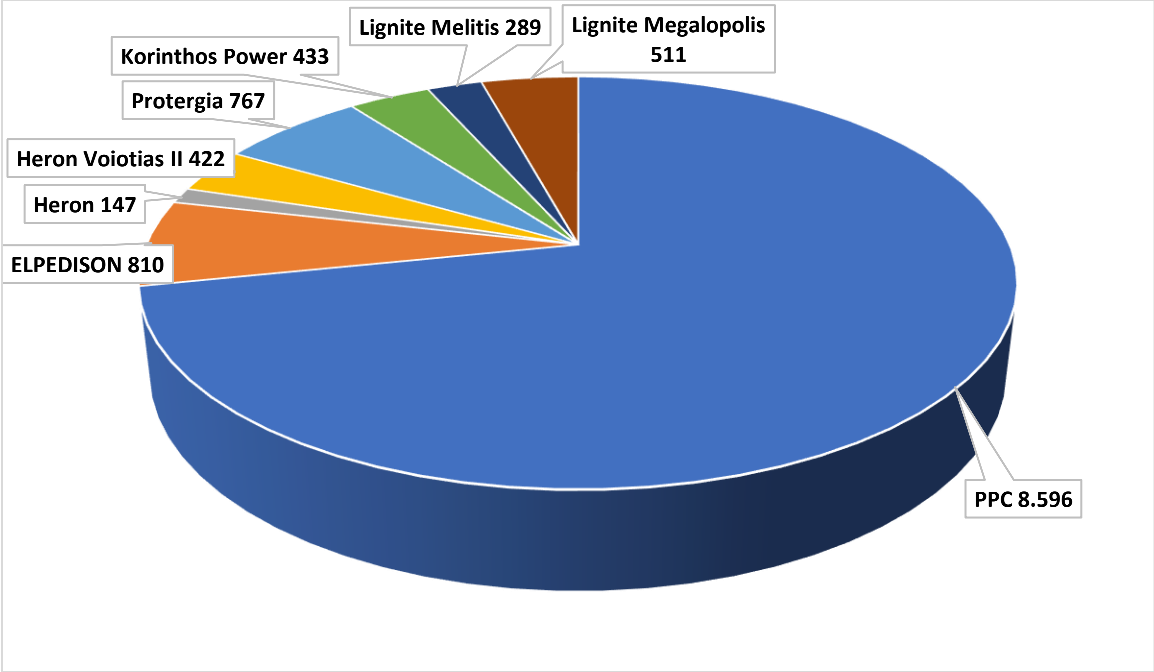


Figure 6: Installed (net) capacity (MW and as a percentage of total capacity) of power units in 2018, excluding RES

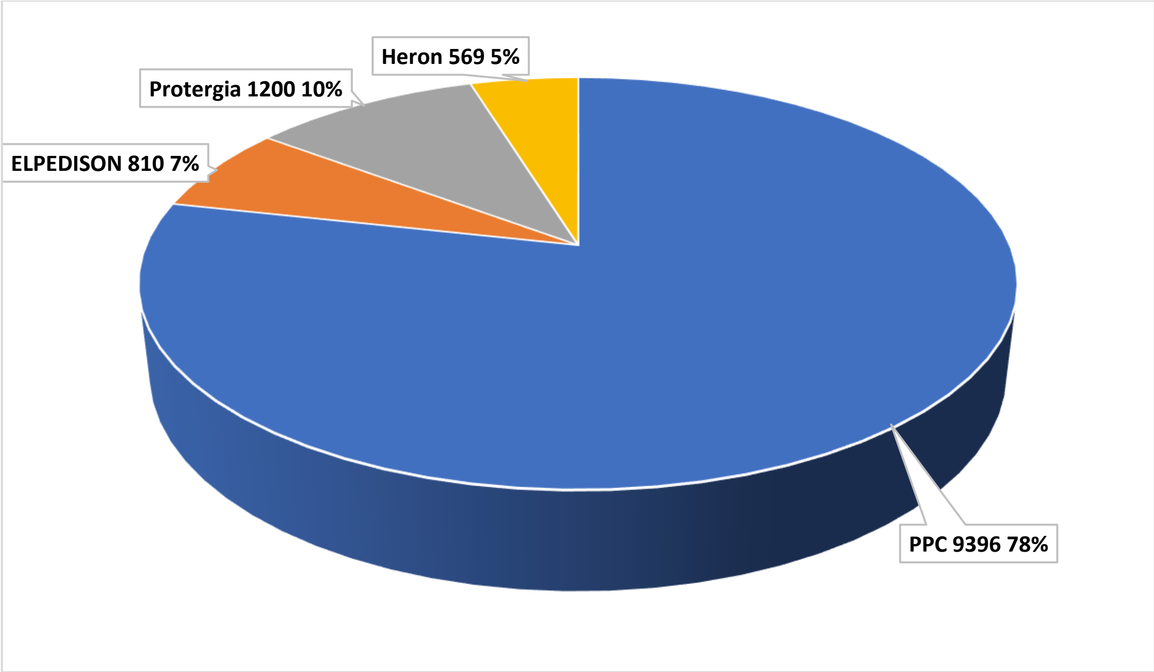


Figure 7: Installed (net) capacity (MW and as a percentage of total capacity) per producer in 2018, excluding RES

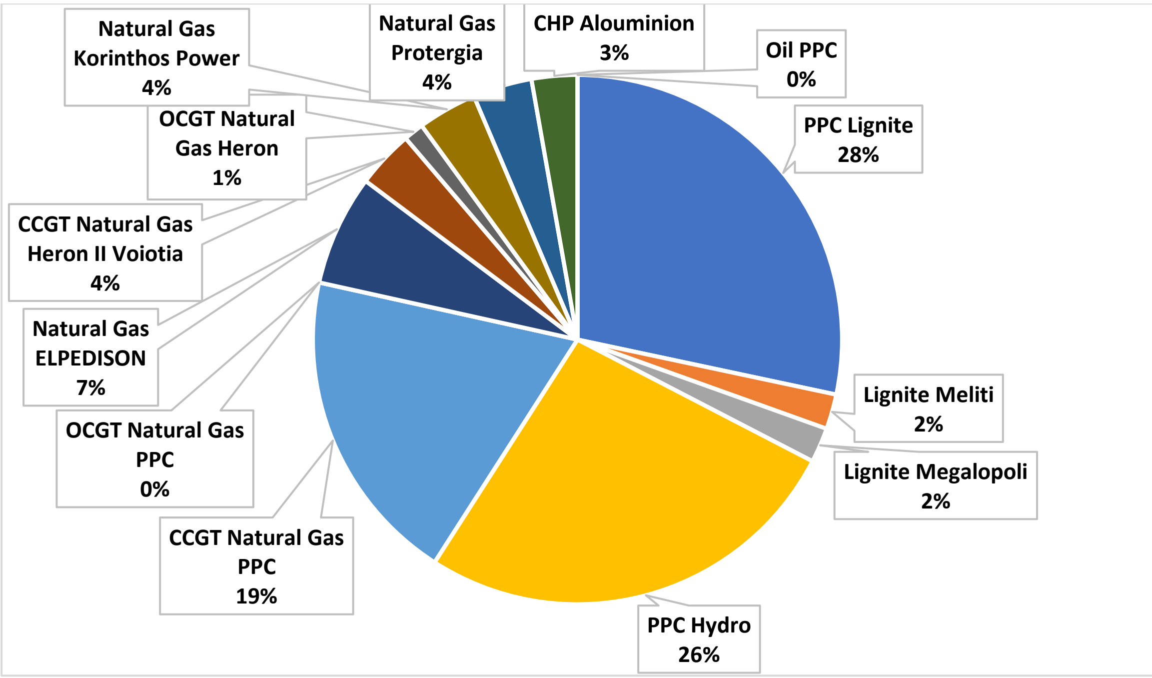


Figure 8: Installed (net) Capacity in 2018 (MW) per producer and fuel (%) excluding RES

In terms of the annual electricity generation, the market shares of the biggest generation companies were as follows:

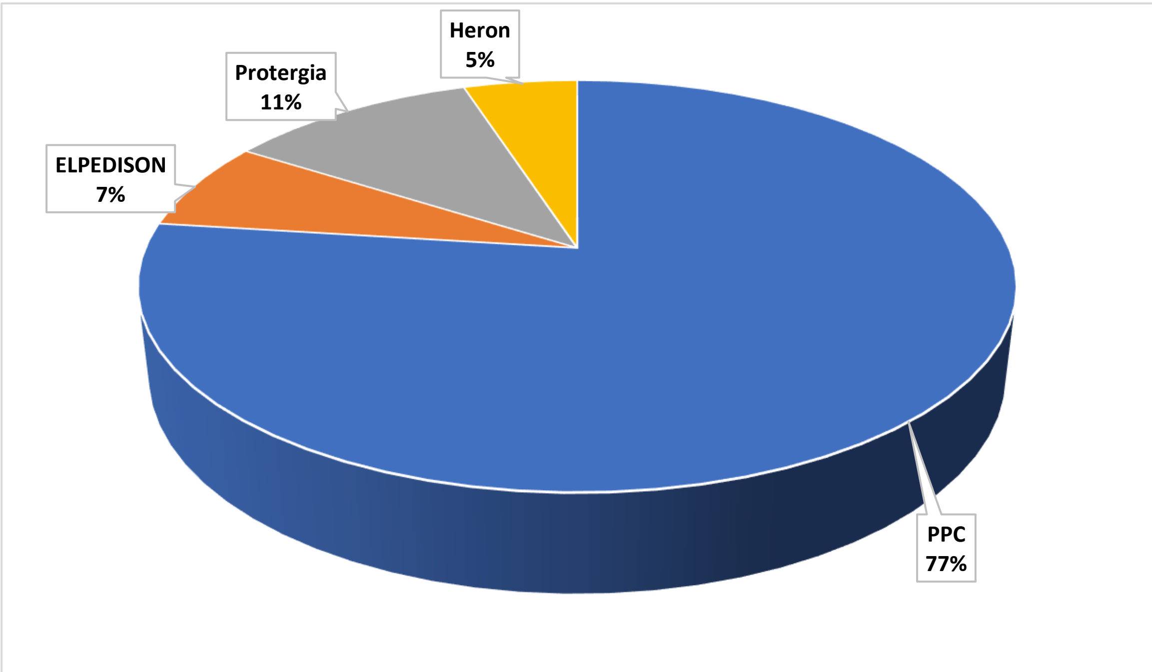


Figure 9: Electricity Generation in 2018 per producer excluding RES

The HHI (Herfindahl index), which sums up the squared number of shares of the biggest companies in the market of electricity generation, continued to decrease in 2018 (4,359) compared to 2017 and 2016 (5,982 and 5,999 respectively). The lower level of concentration in the relevant market shows the important steps made in order to integrate more independent producers. If the same index is calculated in terms of capacity shares then the numbers will amount to 5,627, 6,357 and 6,423 for the years 2018, 2017 and 2016 respectively.

Regarding PPC's share in terms of capacity, on conventional technologies (excluding RES) it dropped from 78.7% to 74.2% whereas including RES it was decreased from 55.2% to 50.9%.

PPC	77%
Elpedison	7%
prot+aloum+kp	11%
Heron	5%
Note: * RES generation from RES is not included	
Year	**HHI index (generation)**
2018	**4,359**
2017	5,982
2016	5,999
2015	7,820

Table 13: Share in electricity generation per Group (%) & HHI Index in 2018

PPC	78%
Elpedison	7%
prot+aloum+kp	10%
Heron	5%

Table 14: Share in installed capacity (MW) by Group (%) in 2018

2018	**PPC**
PPC's Share in installed capacity (except RES)	74.2%
PPC's Share in installed capacity (incl.RES)	50.9%
Year	**HHI index installed capacity**
2018	**5,627**
2017	6,357
2016	6,423
2015	6,804

Table 15: PPCs' Market Share Installed Capacity & HHI Index in 2018

3.2.1.7. Price Monitoring

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.

The average system marginal price (SMP) in 2018 amounted at 60.39 €/MWh continuing its rising trend of the previous years (54.68 €/MWh in 2017 and 42.85 €/MWh in 2016). This constitutes an increase of 10.9% compared to 2017.

With a focus on monthly variations of the SMP we may observe that it fluctuated between 44.27€/MWh (in March) and 71.41 €/MWh (in October). More specifically, the variation on a monthly basis was between -28% and 30%. The average SMP for 2018 decreased from January to March and steadily increased from April to December.

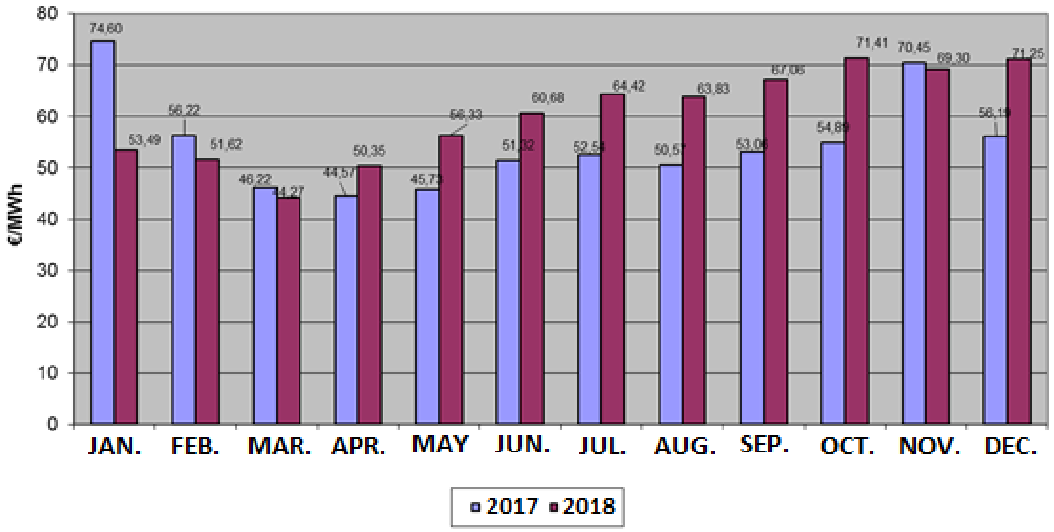


Figure 10: Monthly System's Marginal Price (2017-2018)

The percentage of hours during which the SMP crossed the line of 80 €/MWh was also sharply dropped (1.9% of distribution hours compared to 5.3% in 2017 and 0.2% in 2016).

The SMP was determined mostly by natural gas units (44% compared to 39% in 2017), then by lignite power plants (37% compared to 36% in 2017), followed by imports (11%, same like in 2017), exports (8% compared to 5% in 2017) or hydro plants (3% compared to 6% in 2017).

The hourly variation of SMP was significantly decreased forming an average price daily of 4.47 €/MWh for 2018 compared to 7.83 €/MWh for 2017 and 4.63 €/MWh for 2016.

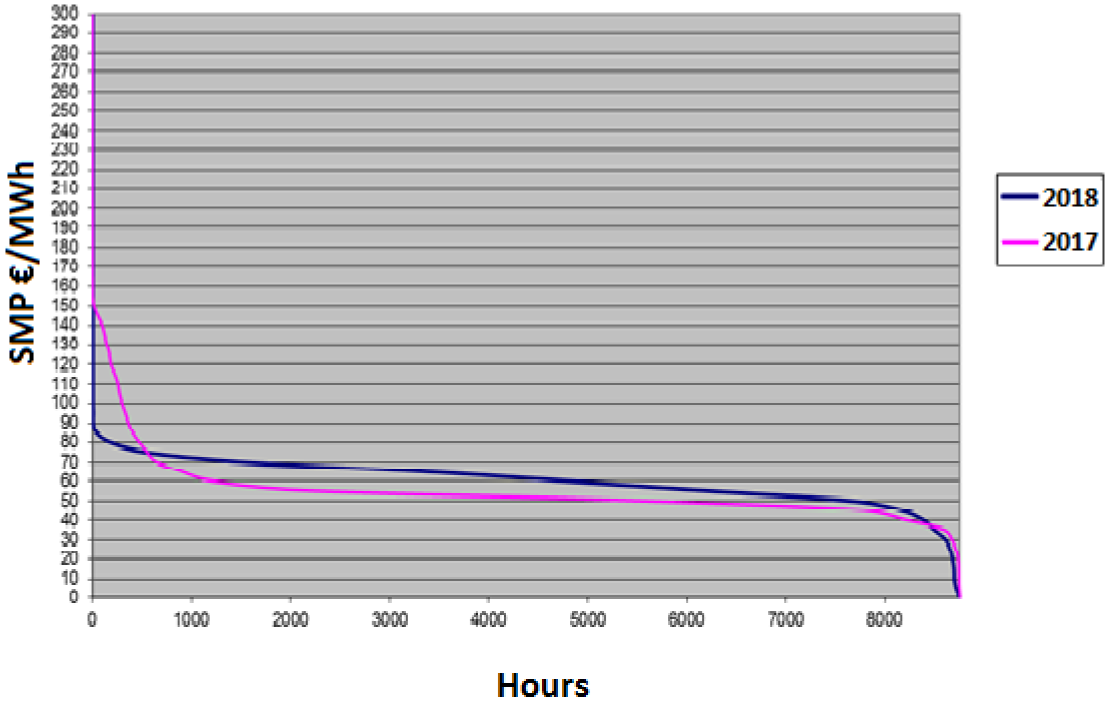


Figure 11: SMP Duration Curve

Regarding the difference between the average SMP and the average imbalance price, on an hourly basis, this amounted to 1,58 €/MWh compared to 3,57 €/MWh in 2017 and 2,78 €/MWh in 2018. The figure below depicts the monthly variations between the average SMP and the average imbalance price.

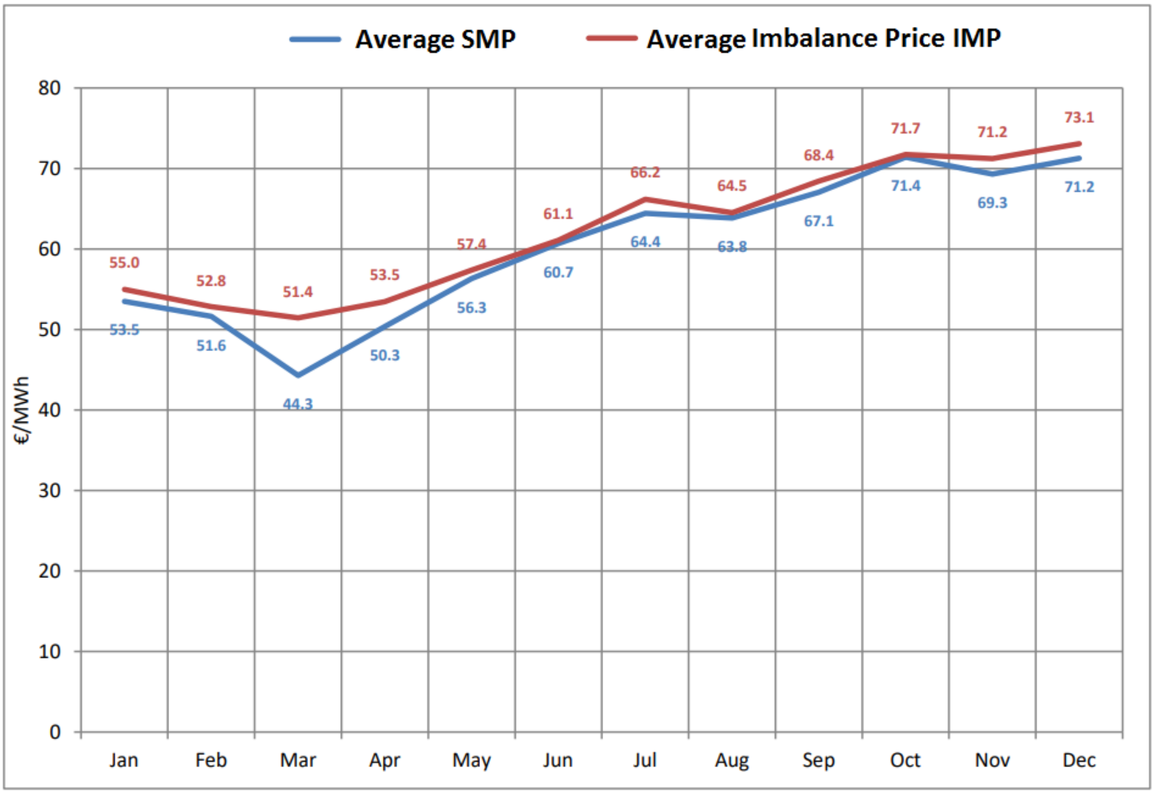
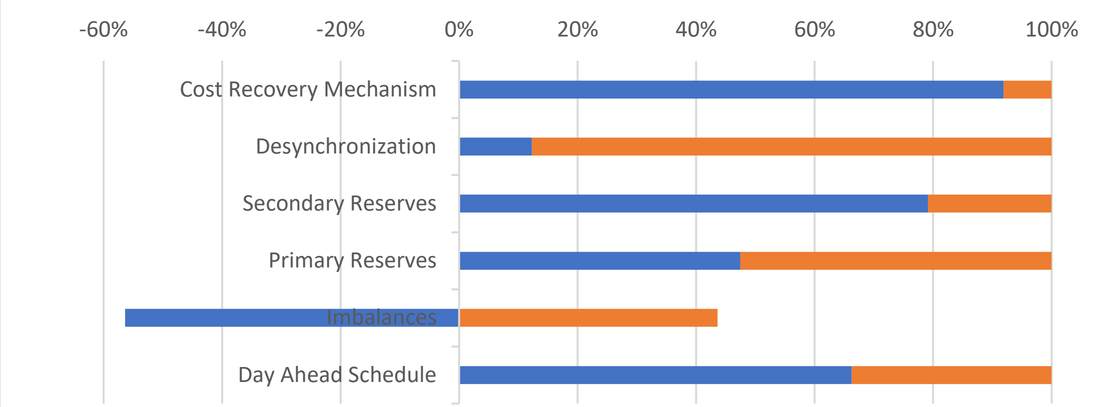


Figure 12: Imbalance Prices IMP (OTA) and SMP (ΟΤΣ) Variation

In terms of cash-flow, the revenues of conventional technology producers (excluding RES) resulting from the resolution of the DAS, amounted to € 2.2 billion in 2018, showing a small increase compared to 2017, during which the equivalent revenues were € 2.1 billion. In 2018, the revenue resulting from the solution of the DAS significantly decreased for PPC (€1.4 billion compared to €1.6 billion in 2017), while for the Independent Producers the trend was the opposite (€731 million compared to €514 million in 2017). The ex-post clearances carried out by the TSO (ADMIE) amounted to € 0.12 billion compared to € 0.11 billion in 2017. In total, the value of the wholesale market amounted to € 2.3 billion in 2018 compared to € 2.2 billion in 2017.

This represents 93% of the total revenues of the electricity producers (compared to 94% in 2017 and 87% in 2016), broken down to 94% for PPC and 88% for the independent producers, as the rest comes mainly from reserves, desynchronization (3%), the mechanism for the recuperation of marginal cost (2%) and the transitory flexibility mechanism (2%).



	Day Ahead Schedule	Imbalances	Primary Reserves	Secondary Reserves	Desynchronization	Cost Recovery Mechanism
PPC	1436,35	-19,18	0,0028	1,29	8	44,16
IPPs	731,26	14,85	0,0031	0,34	57,32	3,9

PPC IPPs

Figure 13: Generators' Revenue by Source (in mil. And in %)

3.2.1.8. Monitoring of transparency

Following the transparency requirements prescribed in the Network 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 ENEX 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.

ENEX 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 ENEX 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 ENEX 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 the effectiveness of market opening and competition

The challenging issues that continued to arise in the domestic electricity market throughout 2018 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 (ENEX). 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 Organisation 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 forward 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 forward 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 forward products, RAE, in 2018, issued a series of regulatory decisions on the gradual development of the relevant mechanism and its adaptation to requirements of the domestic electricity market.

RAE published Decision 82/2018 (Gazette B' 192/26.01.2018) for the readjustment of annual electrical power quantity available through electricity forward auctions with physical delivery and quantity allocation in different forward products for the year 2018 according to Article 135 paragraph 4 and Article 138 paragraph 1 of Law 4389/2016.

For the first scheduled auction of the year 2018, RAE issued Decision No. 83/2018 (Gazette B' 191/26.01.2018) for the approval of technical characteristics and the auctioning terms of the electricity forward product to be auctioned on 7 February 2018, according to paragraph 1 citation D' of Article 138 of Law 4389/2016 (Gazette A' 94/27.05.2016) and of Article 16 of Forward Electricity Product Auction Code (Gazette B΄3164/30.09.2016). The first auction took place on 7 February 2018.

For the second scheduled auction of the year 2018, RAE issued Decision No. 273/2018 (Gazette B' 1292/12.04.2018) for the approval of technical characteristics and the auctioning terms of the electricity forward product to be auctioned on 18 July 2018, according to paragraph 1 citation D' of Article 138 of Law 4389/2016 (Gazette A' 94/27.05.2016) and of Article 16 of Forward Electricity Product Auction Code (Gazette B΄3164/30.09.2016). The second auction took place on 18 July 2018.

For the third scheduled auction of the year 2018, RAE issued Decision No. 652/2018 (Gazette B' 3108/31.07.2018) for the approval of technical characteristics and the auctioning terms of the electricity forward product to be auctioned on 18 April 2018, according to paragraph 1 citation D' of Article 138 of Law 4389/2016 (Gazette A' 94/27.05.2016) and of Article 16 of Forward Electricity Product Auction Code (Gazette B΄3164/30.09.2016). The third auction took place on 18 April 2018.

RAE published Decision No. 748/2018 (Gazette B' 3259/08.08.2018) for the readjustment of annual electrical power quantity available through electricity forward auctions with physical delivery and quantity allocation in different forward products for the year 2018 according to Article 135 paragraph 4 and Article 138 paragraph 1 of Law 4389/2016.

RAE published Opinion No. 9/2018 for the minimum bidding price for electricity forward products according to the definition methodology of Article 139 paragraph 1 of Law 4389/2016 (Gazette A' 94/27.05.2016).

RAE published Decision No. 963/2018 (Gazette B' 4790/26.10.2018) for the definition of administratively fixed price according to paragraph 2 of Article 17 of Forward Electricity Product Auction Code (Gazette B΄ 2306/18.06.2018).

For the fourth and last scheduled auction of the year 2018, RAE issued Decision No. 974/2018 (Gazette B' 4790/26.10.2018) for the approval of technical characteristics and the auctioning terms of the electricity forward product to be auctioned on 17 October 2018, according to paragraph 1 citation D' of Article 138 of Law 4389/2016 (Gazette A' 94/27.05.2016) and of Article 16 of Forward Electricity Product Auction Code (Gazette B΄3164/30.09.2016). The fourth auction took place on 17 October 2018.

RAE published Decision No. 1248/2018 (Gazette B' 6150/31.12.2018) for the setting of electrical power quantity available through electricity forward auctions with physical delivery and quantity allocation in different forward products for the year 2019 according to Article 138 paragraph 1 of Law 4389/2016.

In view of planning the auctions for the year 2019, RAE after the relevant submission of the proposal by the Greek Energy Exchange issued Decision no. 1248/2018 (Government Gazette B' 6150/ 31.12.2018) 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.

3.2.2. Retail Market

3.2.2.1. Description of the retail market

Electricity consumption for 2018 slightly decreased compared to 2017 in the Interconnected System (45,898 GWh compared to 46,876 GWh, i.e. a drop of 2%), due to the total lower consumption of domestic customers (-6%) and ’other’ customers (-8%). Table 16 illustrates the evolution of electricity consumption in the Interconnected System during the last 6 years, which depicts a constant decreasing trend for the period 2013-2016m mainly due to the economic crisis in the country. In 2017 this trend was reversed with an increase in all customers‘ categories, which was proved only temporary, as in 2018 it followed a downward direction once again.

	Year	Large Industrial Customers	Domestic customers	Small Industrial & Commercial customers)	Other (e.g. agriculture, public, traction)	TOTAL (GWh)
LV	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**
	2018	-	14.767	9.324	2.983	**27.074**
MV	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**
	2018	-	-	9.049	1.486	**10.535**
HV	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**
	2018	7.351	-	-	937	**8.288**
Total	**2013**	**6.599**	**15.973**	**18.464**	**6.295**	**47.331**
	2014	**6.702**	**15.569**	**17.702**	**6.526**	**46.499**
	2015	**6.805**	**15.817**	**17.596**	**5.900**	**46.118**
	2016	**7.062**	**15.048**	**17.835**	**5.978**	**45.923**
	2017	**7.268**	**15.651**	**18.108**	**5.849**	**46.876**
	2018	**7.351**	**14.767**	**18.374**	**5.407**	**45.898**

Table 16: Evolution of electricity consumption in the Interconnected System (2013-2018)

Regarding the supply market in the Interconnected System, competition was considerably greater in 2018, without any -worth mentioning- problems affecting electricity market. Within 2018, 5 new companies with supply licenses actively entered the supply market:

1. «ENEL GREEN POWER HELLAS»
2. «EUNICE TRADING»
3. «VIOLAR»

4. «KONSTANTINOS MARKOU»
5. «THOMAS SOUMPASIS»

At the end of 2018, in total 25 companies (including the Universal Service Provider) were active in the electricity supply market:

A/A	BRAND	ABBREVIATION
1.	ΒΙ.ΕΝΕΡ Α.Ε. ΕΝΕΡΓΕΙΑΚΕΣ ΕΠΙΧΕΙΡΗΣΕΙΣ Α.Ε.	VIENER
2.	ΒΙΟΛΑΡ Α.Ε.	VIOLAR
3.	ΔΕΗ Α.Ε.	PPC
4.	ECONOMIC GROWTH A.E. ΕΞΕΙΔΙΚΕΥΜΕΝΩΝ ΜΕΛΕΤΩΝ ΚΑΙ ΣΥΜΒΟΥΛΕΥΤΙΚΩΝ ΥΠΗΡΕΣΙΩΝ	ECONOMIC GROWTH
5.	ΕΛΛΗΝΙΚΑ ΤΑΧΥΔΡΟΜΕΙΑ Α.Ε.	ELTA
6.	ELPEDISON A.E.	ELPEDISON
7.	ENEL GREEN POWER HELLAS ΠΡΟΜΗΘΕΙΑ Α.Ε.	ENEL GREEN POWER
8.	ΕΤΑΙΡΕΙΑ ΠΡΟΜΗΘΕΙΑΣ ΑΕΡΙΟΥ ΘΕΣΣΑΛΟΝΙΚΗΣ - ΘΕΣΣΑΛΙΑΣ Α.Ε. (ΖΕΝΙΘ)	ZENITH
9.	EUNICE TRADING A.E.	EUNICE
10.	ΕΤΑΙΡΕΙΑ ΠΑΡΟΧΗΣ ΑΕΡΙΟΥ ΑΤΤΙΚΗΣ ΑΕ	NATURAL GAS ATTIKIS
11.	GREEK ENVIRONMENTAL & ENERGY NETWORK A.E.	GREEN
12.	GREENSTEEL CEDALION COMMODITIES A.E.[8]	GREENSTEEL
13.	ΗΡΩΝ ΘΕΡΜΟΗΛΕΚΤΡΙΚΗ Α.Ε.	HERON
14.	ΘΩΜΑΣ ΣΟΥΜΠΑΣΗΣ Μ.Ε.Π.Ε.	TH. SOUMPASIS
15.	ΙΝΤΕΡΜΠΕΤΟΝ ΔΟΜΙΚΑ ΥΛΙΚΑ Α.Ε.	INTERBETON
16.	ΚΕΝ ΠΑΡΑΓΩΓΗ ΚΑΙ ΕΜΠΟΡΙΑ ΕΝΕΡΓΕΙΑΚΩΝ ΠΡΟΙΟΝΤΩΝ Α.Ε.	KEN
17.	ΚΩΝΣΤΑΝΤΙΝΟΣ Β. ΜΑΡΚΟΥ Α.Β.Ε.Ε.	MARKOU
18.	NOVAERA ENERGY A.E.	NOVAERA
19.	NRG TRADING HOUSE S.A.	NRG
20.	ΟΤΕ ΑΚΙΝΗΤΑ Α.Ε.	OTE ESTATE
21.	ΠΡΟΜΗΘΕΥΤΗΣ ΚΑΘΟΛΙΚΗΣ ΥΠΗΡΕΣΙΑΣ (ΔΕΗ Α.Ε.)	UNIVERSAL SERVICE PROVIDER
22.	ΜΥΤΙΛΗΝΑΙΟΣ Α.Ε. - ΟΜΙΛΟΣ ΕΠΙΧΕΙΡΗΣΕΩΝ	PROTERGIA
23.	VOLTERRA A.E.	VOLTERRA
24.	VOLTON ΕΛΛΗΝΙΚΗ ΕΝΕΡΓΕΙΑΚΗ Α.Ε.	VOLTON
25.	WATT AND VOLT A.E.	WATT & VOLT

[8] GREENSTEEL remained an active supplier in the retail electricity market up to 30/09/2018.

Table 17: Companies active in the electricity supply market (2018)

PPC remained the main supplier in the retail electricity market in 2018, representing 90.99% of the total number of customers in the Interconnected System at the end of 2018 (75.18% of total consumption in LV and MV). It is worth mentioning that the market share of PPC has been constantly dropping (3% within 2018) while the relevant percentage of alternative suppliers has been constantly rising. The Index measuring market concentration is the Herfindahl-Hirschman Index (HHI), which amounted to 5,740 (measured by volume) for the Interconnected System of the Greek electricity retail market, exceeding the limit of 2,000 (limit for high concentrated markets). As of 2018, despite the large number of suppliers being active in the retail market, the latter continues to be highly concentrated.

In December 2018, forty-three (47) supply licenses and fifty-six (58) electricity trading licenses were into force:

• RAE assessed (8) request for supply licenses, (4) requests for amendments of supply licenses, (3) requests for trading licenses, (1) request for amendment of a trading license and (1) request extending the validity period of a supply license. After assessing those requests, RAE issued (4) decisions for granting a supply license, (1) decision granting a license for electricity trading, (1) decision amending a supply license and (1) decision amending a trading license.

• (2) requests for amendments of supply licenses are pending for final decision.

• (1) request for supply licenses and (2) requests for trading licenses are already submitted to RAE and are pending for assessment and final decision.

• the files of (2) requests for supply licenses and (1) request for amending a supply license do not include all the necessary supplementary documentation and therefore are pending for final decision.

• (1) request amending a trading license, (1) request for a trading license and (1) request amending a supply license are pending from the last year (2017).

3.2.2.2. Competition and market shares

PPC remained in 2018 the main retail supplier in the country, representing 90,99% of the meters in the interconnected system in December 2018 (and 75,18% of the total consumption therein in the low and medium voltage). The figure below presents the evolution of market shares in the supply market per month in the interconnected system.

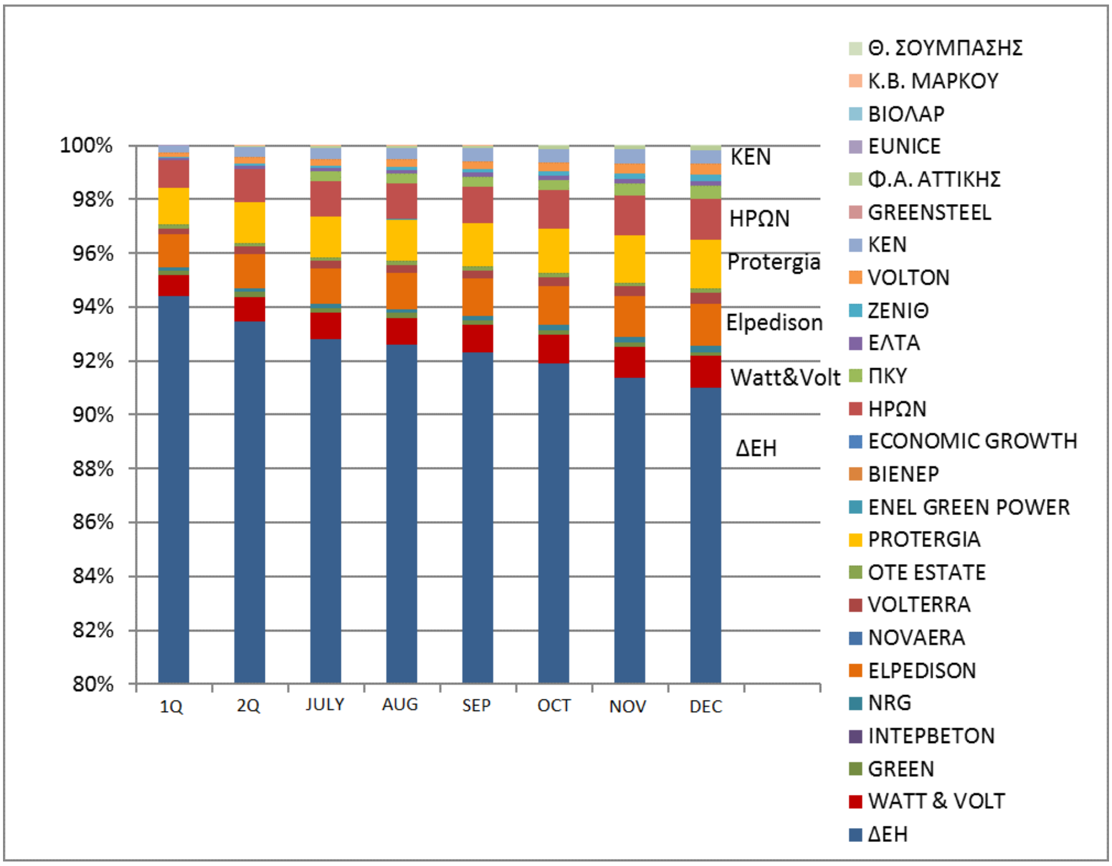


Figure 14: Market shares evolution per month in Retail Electricity Market based on suppliers' total meter connections in the Interconnected System (2018)

Alternative suppliers show better results in terms of volumes. The figure below shows the monthly evolution of market shares in the interconnected system per volume rates in the low and medium voltage.

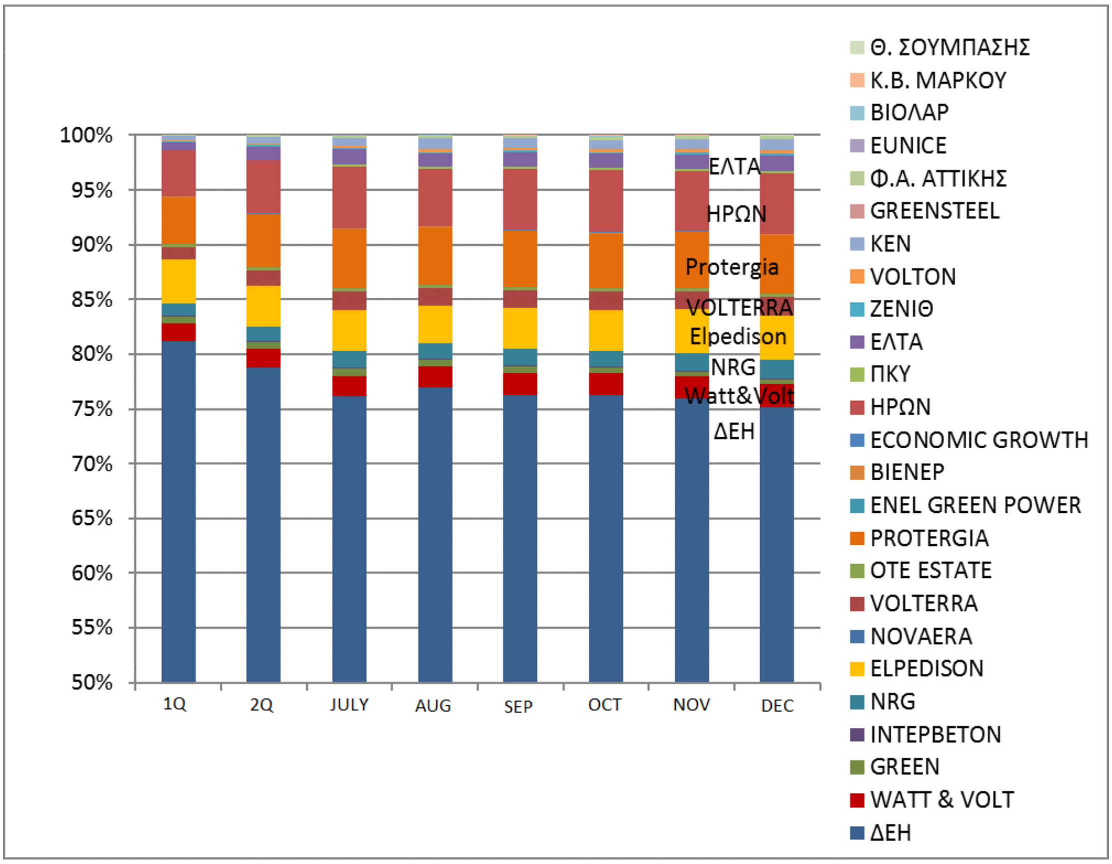


Figure 15: Market shares evolution per month in Retail Electricity Market based on based on consumption volume (LV and MV)in the Interconnected System (2018)

The Herfindahl-Hirschman Index (HHI), at the end of 2018 amounted to 5.740 in the interconnected system per volume, surpassing considerably the 2.000 level (of a totally concentrated market). Regardless of the numbers of the alternative suppliers growing over the past years in Greece, the supply market in 2018 remains highly concentrated.

Regarding suppliers switching rates, according to HEDNO's data 4.51% of LV and MV customers changed their supplier in 2018 (3.96% of total consumption in the LV and MV market). The greatest level of supplier switching is observed at MV (commercial and industrial) customers in terms of both number of customers and consumption volume. The overall rates showed a rise in switching by 60.5% with respect to the number of customers and by 107% with respect to consumption volume. The rise is reasonable taking into account the competition dynamic in the electricity supply market in 2018 and the mechanism of auctioning of forward products (NOME) that continued to occur.

The following table includes data regarding customer switching (LV and MV) in the Interconnected system for 2018 (data of HEDNO):

Customer Category	Number of Customers in the Interconnected System in 31.12.2018	Number of customers that switched supplier in 2018	Switching rates (% in number of customers)	Total Consumption in 2018 (MWh)	Consumption of customers that switched supplier in 2018 (MWh)	Switching rates (% of consumption volume)
Household customers	5.267.262	238.582	4,53%	14.766.728	416.115	2,82%
Small industrial and LV Customers	1.164.486	64.588	5,55%	9.324.446	445.035	4,77%
Oher LV customers	308.887	424	0,14%	2.983.262	3.312	0,11%
Total LV customers	**6.740.635**	**303.594**	**4,50%**	**27.074.436**	**864.462**	**3,19%**
Commercial and Industrial MV customers	8.841	952	10,77%	9.049.083	612.678	6,77%
Oher MV customers	1.647	22	1,34%	1.486.323	11.102	0,75%
Total MV customers	**10.488**	**974**	**9,29%**	**10.535.406**	**623.780**	**5,92%**
Total no of LV and MV customers	**6.751.123**	**304.568**	**4,51%**	**37.609.843**	**1.488.242**	**3,96%**

Table 18: Consumer switching (LV and MV) in the Interconnected system (2018)

3.2.2.1. Price monitoring

Prices for all electricity consumers 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.

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.

RAE, in the context of its responsibilities for monitoring and supervision of energy market (Article 22 of Law 4001/2011) and in particular in the context of monitoring the conduction of activities and the compliance with suppliers licenses' obligations (Article 13 of Law 4001/2011, Codes of Electricity and Natural Gas Supply to Customers), as well as given that from 1st January 2018 both electricity retail market in the Non-Interconnected Islands and natural gas retail market have been fully liberated, has enhanced the monitoring of energy markets, by collecting and processing data of supply and distribution activities of electricity and gas retail energy markets. RAE collects periodically data by active Electricity and Gas Suppliers and Operators on:

- Supply activity of active suppliers of electricity and natural gas
- Distribution activity of operators of electricity and natural gas
- Sustainability financial data of supply and production activities (for enterprises that are active both in production and supply activity)
- Information on complaints and consumer requests

Even more, RAE, at the end of 2018 has undertaken the development of a financial-methodological tool / application (retail monitoring tool) in order to automate the process of collecting and processing data from suppliers and operators, which is expected to become operational within 2019.

Tariff deficit

RAE through 2018 intensified its effort to monitor the financial transactions of Retail Market Participants emphasizing on electricity supply (considering that natural gas market was liberalized in the beginning of 2018), and more specifically the implementation of obligations of Suppliers for Fixed Tariffs attribution to the relevant Operators. Such tariffs are the RES Levy, the Public Service Obligations (PSO) and the Distribution and Transmission Network Tariffs.

RAE examined by sampling overdue payments of Retail Market Participants towards Market Operators in order to evaluate the cash flow between Operators, Producers, Suppliers and Traders. From that assessment RAE discovered that 8 companies were holding a high rate of overdue payments. Those companies were called for hearing on the grounds of not attributing the Fixed Tariffs as they should.

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, 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 Load Representatives' Additional charge of Special Account of RES and CHP 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 enough 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.

Separate Financial Accounts of Supply Activity of Horizontal Integrated Enterprises

RAE, in the context of its responsibilities for monitoring and supervision of energy market (Article 22 of Law 4001/2011) and, in order to avoid discriminations, cross-subsidies and distortions of competition in retail markets of Electricity and Natural Gas, conducted a public consultation regarding the 'Guidelines on the Standard Rules of distribution of Assets and Liabilities, as well as Expenditures and Revenues, for the Preparation of Separate Accounts of Supply Activity in Electrical Energy and Natural Gas of Horizontal Integrated Enterprises, according to provisions of Law. 4001/2011'. More precisely, a Horizontally Integrated Enterprise undertaking both the supply activity of gas and electricity, is subject to the obligation of maintaining separate financial statements for the performance of these two business segments of supply, being also subject to the rules established by RAE, while having the possibility to maintain consolidated accounts for activities other than supply of electricity and gas. The results of the public consultation will be announced at the beginning of 2019 and the relevant Decision on the Guidelines will be issued within the first quarter of 2019.

Electromobility in Greece

The Regulatory Framework for the establishment of an adequate Electrical-Vehicle Charging infrastructure, both in terms of quantity of charging points as well as their density in terms of spatial location, is a regulatory challenge for the development of a national electric vehicle market.

Since 2014, the institutional framework for recharging infrastructure has significantly evolved in Europe. Regarding the main legal & Regulatory framework, the EU Directive 2014/94/EU on the deployment of alternative fuels infrastructure (AFID) foresees that (a) Operators of recharging points accessible to the public are free to purchase electricity from any supplier, (b) Operators of publicly accessible recharging points can provide recharging services to customers on a contractual basis, on behalf of other service providers and (c) Smart metering systems are used, if it is technically feasible and economically reasonable, for recharging in publicly accessible recharging points. During the past few years, a number of legislative provisions on electromobility has been established in Greece, starting with Law 4277/2014 (amendment of Law 4001/2011) that includes the definition of Charging Point Operator. This Law foresees the adoption of a Joint Ministerial Decision following an opinion of the Regulatory Authority for Energy (RAE) on the role and obligations of operators of recharging points.

Law 4439/2016 incorporated the European Directive (EU Directive 2014/94/EU) into the Greek legislation and Law 4513/2018 allowed the installation of EV charging points in public areas. On 31 October 2017, by Joint Ministerial Decision No 77226/1, the National Policy Framework for the Development of Alternative Fuels Infrastructure Market in the transportation sector was established as required by Article 3 of Directive 2014/94/EU.

RAE, in the light of its responsibility for issuing an opinion to the relevant Ministers, raised several key issues for public consultation in order to clarify and delineate the institutional and operational framework for the integration of electric vehicle recharging infrastructure in Greece. Fifteen (15) participants submitted comments to RAE on the above public consultation. RAE, after processing the comments submitted and considering the provisions of parag. 2, Article 134 of Law 4001/2011, as amended by Article 53, parag. 3 of Law 4277/2014, as well as provisions of Law 4493/2016, is expected to issue an Opinion on the conditions and operation of Electric Vehicle Recharging Infrastructure, within the first quarter of 2019.

In addition, in the context of further strengthening the electromobility sector, RAE submitted a recommendation to the Minister of Environment and Energy towards amending provisions of Law 4001/2011, by adding a subparagraph after the second subparagraph of Article 81, par. 1, according to which no supply license would be required for the sale of natural gas from fuel stations to vehicles' electric motors end-use.

3.3. Security of supply

According to article 12, Law 4001, 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 19 presents the evolution of annual electricity consumption and peak load in the interconnected system, since 2009, as reported by the TSO, ADMIE S.A. In 2018, the amount of electricity demand reached 51,46 TWh which is a decrease of 0,91% comparing to 2017 demand.

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Total electricity consumption excluding pump storage (GWh)	53.490	53.545	52.915	52.611	50.664	50.228	51.355	51.212	51.932	51.460
Peak load (MW)	9.809	9.872	10.105	10438	9.161	9.263	9.813	9.207	9.674	9.100

Table 19: Energy and peak electricity demand in the interconnected system (2009-2018)

Table 20 presents a forecast of the evolution of annual electricity consumption and peak demand in the interconnected system for the period 2018 - 2027, according to the Ten-Year Network Development Plan (TYNDP) of the TSO for the period 2018-2027, which approved by 256/2018 RAE Decision.

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total electricity consumption excluding pump storage (GWh)	54310	55840	57325	57750	58180	60250	60740	61230	61730	62230
Peak load (MW)	10.190	10.510	10.625	10.700	10.780	11.370	11.460	1.550	11.650	11.740

Table 20: Energy and peak electricity demand forecast in the interconnected system, for the period 2019-2028

In 2018 the total electricity demand was decreased by 1% compared to 2017. The high-voltage electricity consumption continued its recovery trend for the fourth consecutive year (1.13% versus 2.96% in 2017, 3.76% in 2016 and 0.47% in 2015). In fact, it is worth noting that in January and July 2018 the change in demand in high voltage was up by 8.35% and 5.98% respectively, compared to the previous year. The maximum annual rate of electricity consumption was recorded in July and it amounted to 656 GWh against 646 GWh in 2017, 621 GWh in 2016 and 589 GWh in 2015. In the coming decade an average increase in electricity demand is expected of about 0.85% per year.

On the list with the main risks for security of supply, on a short term, 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

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 September 2018 to RAE, a Generation Adequacy Report[9] for the period 2019-2030. 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. The 2018 Generation Adequacy Report examined alternative demand and generation scenarios, which were formed based on relevant estimates-forecasts by the Transmission System Operator. Specifically, the adequacy of the Greek power system was estimated through probabilistic methods, by calculating the LOLE (Loss of Load Expectation) and EUE (Expected Unserved Energy) reliability indices, considering many decommissioning scenarios of thermal capacity, growth in power demand, renewable and cross-border transmission capacities and hydraulic conditions. The basic methodology and assumptions used by the TSO in the national adequacy study have been aligned to a large extent with the methodology used in ENTSOE' s European Midterm Adequacy Forecast (MAF), issued in 2016. In this light, the assessment of the effect of climate factors (air, sunshine and temperatures) on the adequacy of the power system was taken into consideration. Specifically, for each demand evolution scenario and year, different time series of loads and RES generation were developed

[9] http://www.ypeka.gr/LinkClick.aspx?fileticket=W%2FLndQ4wluo%3D&tabid=232&language=el-GR

using the available historical data of the PECD 2.0 database maintained by ENTSO-E. These time series correspond to different climatic conditions, covering a wide range of potential, both "normal" and "extreme".

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 2019-2030 is set. This scenario includes the new entries and withdrawals of thermal plants. The adequacy analysis presents the reliability indices for the period 2019 – 2030, 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, for mild RES penetration, the LOLE average values for most of the cases, over the 2019-2030 period, do not satisfy the reliability criterion, except of some specific, favorable, conditions (especially of high hydraulicity) only for the two years 2024-2025. Scenarios that are based on higher RES penetration lead to improved reliability indices (compared to the mild RES scenario), but in most cases the reliability criterion is still not met, except of the particularly favorable case of high hydraulicity for the years 2022-2026. Considering the EUE indices, it seems that in most of cases the power system is expected to have a high risk of inadequate peak coverage. Furthermore, at the end of the period under consideration, EUE indices reveal an increased risk of inadequate coverage also for the non-peak loads.
- The simultaneous withdrawal of the units of Kardia and Amydaio (end of 2018, early 2019), jeopardize the adequacy of the power system over the next two years 2019-2020 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 mid of 2021 seems to compensate for the loss of the units of the Kardia and Amydaio, improving the values of the LOLE indicator until 2023, despite the integration of all Crete's demand to the mainland power generation system.
- The significant increase of the LOLE and EUE values since 2026 is due the withdrawal of Megalopolis III at the end of 2025.
- The simultaneous withdrawal of the units of Agios Dimitrios I and Agios Dimitrios II at the end of 2029 lead to a significant increase of reliability indicators.
- The assumed hydraulic scenario affects significantly the values of LOLE indicator.
- The Reference Scenario of the adequacy analysis presumes no premature retirement of thermal power plants takes place. However, current market conditions appear to place considerable challenges on CCGTS and lignite plants – i.e. increased CO_2 prices, high RES penetration etc., - which are much needed for achieving the above adequacy standards.
- It should not be ignored that the contribution from the interconnections may be quite uncertain during scarcity periods (coincident peaks, cold spells, gas supply crises etc.), therefore the adequacy of the power system could be even worse.

Taking into consideration the above findings of the Adequacy Study assessment of interconnected electricity System for the period 2019-2030, the situation of the Greek electricity market, the EU legislative environment (European Commission’s Guidelines for State Aid in the sectors of Environment and Energy for 2014-2020 [2014/C 200/01) and the approved Decisions from the European Commission for the implementation of Adequacy Mechanisms in other countries, RAE submitted in 2018 a suggestion to the Ministry of Environment and Energy for a Long Term Capacity Remuneration Mechanism design.

3.3.2. Monitoring investment in generation capacities

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 2018 are presented in section 3.2.1.3.

Furthermore, according to the latest TYNDP for the period 2018-2027 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.

On 7 February 2018, the Commission adopted a decision approving the prolongation of the interruptibility scheme for the Greek electricity system (2018) 604 final/7.2.2018 in State aid case "SA 4870" - Prolongation of the Greek interruptibility scheme). Under the measure, the TSO contracts large energy consumers to be available to reduce their consumption at times of system stress, also referred to as demand response.

In exchange for being available to be disconnected, the beneficiaries are remunerated with a fixed payment which is determined by means of three-monthly auctions. Beneficiaries can bid to provide two different services, summarized in Table below. In order to be eligible for participation in the tenders for the interruptibility scheme, the minimum threshold is a capacity of 3 MW. The installations must moreover be connected to the transmission grid or the medium voltage network.

Types of Interruptible load services (ILS)	**Warning time**	**Maximum time of order**	**Maximum time per year**
Type 1*	5 minutes	48 hours	288 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.

Table 21: Interruptible load services (ILS)

In the above Decision, the duration of the measure was set at 2 years, i.e. until 31.12.2019 and beneficiaries of this are customers whose premises are connected to HV and MV with intermittent power of at least 3MW, 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. In total, the Greek TSO can contract up to 1600 MW of so-called interruptible loads, i.e. demand response from medium-sized and large energy users with a stable load profile. The 1600 MW are split in two separate segments: 1000 MW of capacity can be contracted for ILS1 and 600 MW for ILS2. The maximum price at which the auction can clear is EUR 70000/MW for ILS1 and EUR 50000/MW for ILS2.

In 2018 the Greek TSO (ADMIE) organized five pairs of auctions (one auction for each type of ILS). The four pairs of auctions covered the period from January 17th to December 31^{e} 2018 and the fifth pair of auctions covered the first quarter of 2019. For ILS1 auctions the capacity asked by the TSO ranged from 600MW to 620MW. For ILS2 auctions the capacity asked by the TSO ranged from 430MW to 450MW. The results of the auctions are summarized in the tables below.

Month of Auction	Period of Auctions	Marginal price (€/MW-year)	Number of participants succeeded in auction	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)
January	17.01.2018 - 28.02.2018	55.000	24	680,5	600	80,5
February	01.03.2018 - 31.05.2018	56.900	24	711,4	620	91,4
March	01.06.2018 - 30.09.2018	59.700	23	681,5	600	81,5
April	01.10.2018 - 31.12.2018	60.450	22	696,9	600	96,9
December	01.01.2019 - 31.03.2019	59.350	23	661	600	61

Table 22: Type 1 of Interruptible load capacity services (ILS 1 services) Auctions in 2018

Month of Auction	Period of Auctions	Marginal price (€/MW-year)	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)
January	17.01.2018 -28.02.2018	42.000	501,4	450	51,4
February	01.03.2018 -31.05.2018	44.000	510,5	450	60,5
March	01.06.2018 -30.09.2018	43.000	507,6	430	77,6
April	01.10.2018 -31.12.2018	49.000	529	430	99
December	01.01.2019 -31.03.2019	49.800	482,1	430	52,1

Table 23: Type 2 of Interruptible load capacity services (ILS 2 services) Auctions in 2018

3.4. The Non-Interconnected islands system (NIIs)

The completion of Phase 1 of Cyclades interconnection (Syros, Mykonos, Paros) with the interconnected system in 2018, was a turning point for the Greek electricity system. Nevertheless, a great number of islands are still electrified from local production units of PPC which operate on oil products[10].

The contribution of RES is important (wind turbines and PVs) which operate on those islands. RES share in the non-interconnected systems amounted to 17.2% of total power consumption in 2018. In Crete, this percentage touched 21.32% of total power consumption. However, until power stocking through hybrid units reaches a level where they can guarantee energy autonomy for those islands, the non-interconnected systems will still rely mainly on thermal units that use oil as fuel.

All remaining Greek Non-Interconnected Islands (NNIs) are electrified by autonomous electrical units. Renewable energy sources (wind parks and small photovoltaic stations), most of which are owned by independent producers (other than PPC S.A.), contribute with a significant percentage in the total NII electricity production per year (not exceeding 15-20% for each NII).

3.4.1. Electricity Supply Structure

In the non – interconnected islands 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 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

[10] 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 derogation is valid until 1 January 2021. 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: (1) 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.

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. All suppliers that are active in NII can buy the produced electricity.

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.

The description of the retail electricity market in the Non-Interconnected Islands is distinguished from the Interconnected System in 2018, as of 01.01.2018 and, according to RAE Decision No. 908/2017 (Government Gazette 4461 B '/ 19.12.2017), the full liberalization of electricity supply in the Non-Interconnected Islands was enacted.

By the end of 2018, 15 suppliers (including the Universal Service Provider) were active in the Non-Interconnected Islands:

Supplier Name:

1. PPC
2. ECONOMIC GROWTH
3. ELTA
4. ELPEDISON
5. NATURAL GAS ATTICA
6. GREEN
7. HERON
8. KEN
9. NRG
10. OTE ESTATE
11. UNIVERSAL SERVICE PROVIDER
12. PROTERGIA
13. VOLTERRA
14. VOLTON
15. WATT & VOLT

PPC remained the main supplier in the retail electricity market of the NIIs in 2018, representing 93.30% of the total number of customers in the NIIs at the end of 2018 (84.50% of total consumption in LV and MV).

The Herfindahl-Hirschman Index (HHI), measuring market concentration, amounted to 7,179 for the NIIs (measured by volume). This figure exceeds by far the limit of 2,000 (limit for highly concentrated markets). All in all, the retail electricity market of the NIIs is rightly characterized as still very concentrated and, as shown above, even more concentrated compared to the Interconnected System of the country.

Regarding supplier switching in the NNIs, according to HEDNO's data 4.28% of LV and MV customers changed their supplier in 2018 (3.72% of total consumption in the LV and MV market). The greatest level of supplier switching is observed at MV (commercial and industrial) customers in terms of both number of customers and consumption volume.

The following table includes data of customer switching (LV and MV) in the NIIs for 2018 (data of HEDNO):

Customer Category	Number of Customers in the NIIs in 31.12.2018	Number of customers that switched supplier in 2018	Switching rates (% in number of customers)	Total Consumption in 2018 (MWh)	Consumption of customers that switched supplier in 2018 (MWh)	Switching rates (% of consumption volume)
Household customers	591.095	23.894	4,04%	1.648.415	45.285	2,75%
Small industrial and LV Customers	153.478	9.708	6,33%	1.706.118	78.078	4,58%
Oher LV customers	43.027	28	0,07%	473.208	158	0,03%
Total LV customers	**787.600**	**33.630**	**4,27%**	**3.827.742**	**123.521**	**3,23%**
Commercial and Industrial MV customers	995	120	12,06%	1.111.453	67.253	6,05%
Oher MV customers	181	0	0,00%	188.390	7	0,00%
Total MV customers	**1.176**	**120**	**10,20%**	**1.299.843**	**67.260**	**5,17%**
Total LV and MV customers in the NIIs	**788.776**	**33.750**	**4,28%**	**5.127.586**	**190.781**	**3,72%**

Table 24: Consumer Switching (LV and MV) in NIIs (2018)

3.4.2. Electricity Generation Capacity and Electricity Demand

The share of RES' generation in the total electricity generation of the 29-autonomous power system was 17,7% in 2018. In Crete, the largest island of the non- interconnected system the share of RES in total generation was 21,97%. The level of demand of the 29 autonomous non-interconnected islands varies significantly:

- 19 out of 29 have a peak demand level not more than 10MW.
- 8 out of 29 have a peak demand level from 10 MW up to 100MW.
- And only 2 autonomous non-interconnected islands have a peak demand level over 100MW (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).

	Non-interconnected autonomous power systems (islands)	**Final Electricity Production from Conventional Plants (MWh)**	**Electricity Produced from RES and rooftop PV's (MWh)**	**Electricity Injected to the electricity systems using Net Metering (MWh)**
1	St Eustratios	1,124.01	0.00	0.00
2	Agathonisi	717.56	0.00	0.00
3	Amorgos	10,742.21	468.36	0.00
4	Anafi	1,370.58	0.00	0.00
5	Antikythera	274.30	0.00	0.00
6	Arkie	397.05	0.00	0.00
7	Astepalaia	6,545.19	559.85	0.00
8	Gavdos	491.02	0.00	0.00
9	Donoussa	1,118.38	0.00	0.00
10	Erikoussa	894.94	0.00	0.00
11	Thira	199,310.89	953.27	0.00
12	Ikaria	24,920.00	3,097.62	0.58
13	Karpathos	35,000.23	3,494.49	0.00
14	Crete	2,404,160.02	676,768.25	71.54
15	Kythnos	9,179.02	399.30	0.00
16	Kos	342,429.64	51,886.19	12.38
17	Lesbos	256,655.48	42,778.14	7.33
18	Lemnos	50,352.64	10,062.71	2.56
19	Megisti	3,761.56	0.00	0.00
20	Melos	43,722.87	6,945.93	0.00
21	Mykonos*	30,642.00	1,556.49	2.34

22	Othonei	639.65	0.00	0.00
23	Paros*	25,719.81	10,886.78	0.00
24	Patmos	15,977.55	2,964.36	0.00
25	Rhodes	744,677.29	121,670.48	3.75
26	Samos	114,555.87	25,736.03	9.76
27	Serifos	8,536.34	219.41	0.00
28	Sifnos	18,741.58	577.62	0.00
29	Skeros	15,221.05	481.49	0.00
30	Semi	14,417.45	255.16	0.00
31	Syros*	16,871.11	1,174.41	6.29
32	Chios	187,122.09	20,872.82	0.00
	TOTAL	4,586,289.38	983,809.16	116.53

Table 25: Electricity Generation in Non-Interconnected Islands (NII) for 2018

Non-interconnected islands	2011	2012	2013	2014	2015	2016	2017	2018
St Eustrations	1.066	1.102	1.075	1.115	1.118	1.096	1.095	1.124
Agathonisi	542	599	642	650	702	749	727	718
Amorgos	9.633	9.354	9.129	9.334	9.865	10.069	10.710	11.188
Anafe	1.137	1.199	1.179	1.223	1.259	1.277	1.298	1.371
Antikythera	238	216	241	243	261	255	276	274
Astepalaia	7.022	7.089	6.670	6.599	6.772	6.856	7.008	7.064
Donoussa	717	667	690	721	810	841	1.016	1.118
HEreikousa	664	746	746	697	795	832	879	895
Thera	120.057	120.817	120.199	135.772	152.375	164.060	181.674	199.744
Ikaria	29.096	28.977	27.613	27.423	28.658	27.129	28.047	27.878
Karpathos	38.784	38.988	36.931	36.928	37.966	37.799	37.319	38.455
Kythnos	8.719	8.672	7.991	8.240	8.607	9.005	9.586	9.578
Kos-Kalemnos	361.514	361.681	352.984	351.942	367.337	368.521	382.075	392.964
Lesvos	307.864	300.822	288.230	285.542	296.582	297.670	299.860	299.177
Lemnos	61.795	61.743	59.672	58.486	60.244	59.831	60.411	60.378
Megisti	2.973	3.126	3.005	3.152	3.207	3.479	3.549	3.762
Melos	48.272	49.952	45.402	47.885	49.834	47.642	49.181	50.573
Othonoi	709	688	632	634	634	601	645	640
Patmos	17.825	17.475	17.020	17.019	17.788	17.477	18.438	18.894
Samos	150.604	146.503	137.315	136.178	138.186	138.050	140.447	140.252
Serifos	8.299	8.153	7.654	8.178	8.358	8.202	8.680	8.701
Sifnos	17.905	17.364	16.521	17.047	17.617	17.984	18.633	19.069
Skeros	15.698	15.549	14.782	15.073	15.955	15.663	16.266	15.666
Semei	15.031	15.275	14.662	14.132	14.649	15.175	14.285	14.673
Chios	215.739	212.476	200.042	196.993	202.519	205.833	210.435	204.987
Rhodos	780.413	790.593	760.658	760.187	791.768	814.488	836.397	864.624
Crete	2.945.881	2.944.351	2.825.132	2.866.699	2.898.169	2.975.755	3.027.253	3.055.605
Note: Most of the 29 autonomous power systems include more than one island (micro islands)								

Table 26: Non-interconnected autonomous power systems (islands) - Annual Electricity Consumption (Demand) 2011 – 2018 (MWh)

3.4.3. Other regulatory developments in NIIs

Economic efficiency criteria for the electrification of the NNIs

Pursuant to Article 4 of the operative part of the Deviation Decision, RAE with the Decision no. 469/2015 which was later amended with the Decision 169/2018, 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[11]. In December 2017, the Committee 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, was submitted in December 2018. 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 and the second part, which are of 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.
3. The cost for the interconnection of all the examined autonomous electricity systems of the North-East Aegean with the interconnected network (including the interconnection of Skyros and the development of an autonomous electricity system of Ag. Efstratios) is lower than to supply those non-interconnected islands with either natural gas (although marginally) or oil.

In this framework, after holding a public consultation, RAE adopted the recommendation of the above Committee by issuing Decision No. 651/2018 concerning the methodology to be used to determine the interconnection method of certain NII based on several criteria (ex. security of supply, cost efficiency etc.) excluding those already included in the TYNDP of the TSO.

Emergency response system

In the context of implementing the provisions of the NIIs Code for Emergency Response, RAE held a public consultation for the amendment of articles 152 and 155 of the Electrical System Network Code of Non-Interconnected Islands to address emergencies.

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

[11] 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 Committee’s work continued in 2017, with a test of autonomous interconnection systems of the southern and northern Aegean islands.

1. The NIIs Operator shall immediately notify RAE in accordance with the NIIs Code, by the end of the next day of the event.
2. The NIIs Operator shall submit to RAE within the above specified time period a suggestion to grant a production license if an additional potential authorization is required by specifying: the amount of additional capacity, its cost, and the time required to repair the damage.
3. The Producer, based on a recommendation of the NIIs Operator, should submit within a reasonable time period 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 be able to prove (through an adequacy study etc) the necessity for renting additional capacity before RAE approves that extra cost.

Emergency response plan

Pursuant to Article 154 of the NIIs Code the Operator submits to RAE for approval, and updates every five years or earlier, the Emergency Response Plan for the NIIs. With Decision 368/2018 (OJ B' 5666/17.12.2018) the Plan was approved by RAE with certain additional conditions regarding mainly the costs of the measures prescribed therein.

2017 crisis management report

RAE, within the framework of the Non-Interconnected Islands' Operation Code, was informed for the different ways of crisis management by the Operator of NIIs in 2017. Those incidents concerned damaged underwater cables between islands that happened in 2017. RAE will evaluate this crisis management process, the cost of covering those needs, the clearance of Network Tariffs and NIIs Public Service Obligations for 2018 which will take place in 2019.

Opinion for the prevention of delays in the implementation of interconnections

In 2018, RAE, within its remit, as provided in the provisions of the Article 108A of Law 4001/2011 and in the Decision No. 256/2018 for the approval of the TYNDP of ADMIE for 2018-2027, submitted Opinion 14/2018 to the Ministry of Environment and Energy concerning the procedure for calculating and enforcing a clause for the prevention of delays in the implementation of the interconnection of NIIs with the mainland electricity system based on the Non-Avoidable Cost of Public Service Obligation Tariff.

In essence, and with reference to specific timetable for the implementation of each project, penalties may be imposed in cases of delays in the implementation of different stages of each project to the Organization which bears the responsibility of implementing the relevant project.

Infringement procedure against the NIIs Operator regarding the PSO_NIIs administration

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 enforcement of the legislative framework for the proper functioning of the market, and eliminates any distortions or other practices exercised by the Participants and the relevant Operators causing malfunction of the market transactions. 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 Public Service Obligation Account in the Non-Interconnected Islands, and in particular in accordance with Articles 170, 179 and 183 of the NIIs Code, applies certain procedures for the clearance of transactions on a Monthly and Yearly basis, for all Load Representatives in the Market of NIIs, including the issuance of the relevant invoices.

However, with the allegation that the NIIs Operator did not follow the relevant process of the NIIs Code of monthly clearance of transactions for the provision of Public Service Obligations in the Non-Interconnected Islands from July 2016 until the end of the year, (but only asserted amounts to the Load Representatives of the NIIs), RAE invited first the NIIs Operator to a hearing and finally adopted Decisions 212/2018 and 268/2018 imposing penalties against the NIIs Operator.

3.4.4. Environmental Directives

On 31 July 2017, Decision (EU) 2017/1442 of the Commission was published in order to set the conclusions for the Best Available Techniques based on Directive 2010/75/EU of the European Parliament and Council concerning big thermal units. This Decision along with Directive 2015/2193 of the European Parliament and Council for the reduction of certain pollutants in the atmosphere coming from middle-size thermal units and Directive 2010/75 concerning industrial pollutants which reduce the limits for atmospheric pollution.

The Directives mentioned above provided new stricter limits for pollution by generation units and together with strict application deadlines lead to significant reduction of generated capacity especially in Non-Interconnected Islands.

RAE, after taking into consideration those Directives, has called Network Operators to assess their implications on Greece's Security of Supply in cooperation with the Producers and the Commission calculating the efficiency of NIIs electrification.

3.4.5. Security of supply in Crete

The security of supply of Crete has emerged as a major national priority over the past few years because of the EU environmental limitations and the termination of the exemption decision 2014/536/EU of the European Commission at the end of 2019. To this end, RAE has coordinated the relevant actions between the network operators and producer PPC S.A. trying to reach the most effective intermediate solution until the full interconnection of the island with the National Transmission Network.

In this framework, RAE adopted decisions 260/2018 and 1250/2018, issued Opinion 4/2018 to the Ministry of Energy, and addressed the Operators with several letters aiming to address pending technical and regulatory issues.

3.5. RES

3.5.1. RES Installed capacity and generation

The installed capacity of RES units at the end of 2018 amounted to 5,828 MW (including those in NIIs), showing an increase of approximately 5.6% compared to the one recorded at the end of 2017 (5,521MW). This slight increase, which is approximately at the same level compared to the corresponding period of 2016-2017 (then +5.1%), is mainly due to the installation of new wind power plants with a total capacity of 235.9 MW (increase by 9% compared to 2017) as shown by the breakdown by technology at the table below.

Additionally, there has been an increase of the biomass units by 21.7MW (35.2% increase compared to 2017). In 2018 there was also an increase of the installed capacity of photovoltaics by 39.7MW, which was the result of the completion of the projects that received operating aid during the pilot competitive tender procedure held by RAE in 2016. This incremental capacity as absolute figures may not be significant, but a stable investment activity in these sectors is established compared to 2015, 2016 and 2017, and this is true in particular for biomass/biogas technology and mostly for wind power plants; a trend that is expected to continue during the following years due to the operating aid given to new photovoltaic power units and wind power plants that were successful during the 2018 competitive tender procedures held by RAE, but also because of the favorable investment conditions in the country. Furthermore, it should be noted that in the light of a change in the institutional framework with Law 4414/2016 a remarkable increase occurred in the development of small hydroelectric plants with 9.2 MW new installed capacity in 2018.

RES Technology	Installed Capacity in 2016 (MW)	Installed Capacity in 2017 (MW)	Installed Capacity in 2018 (MW)	% Change 2016-2017	% Change 2017-2018
Wind	2,370	2,625	2,860	10.7%	9.0%
PV	2,229	2,230	2,270	0.00%	1.8%
PV on roof	375	375	375	0.00%	0.00%
Hydro Small	223	231	240	3.4%	4.0%
Biomass - Biogas	58	62	83	6.0%	35.2%
Total	5,255	5,521	5,828	5.1%	5.6%
Note: Large Hydro are not included in the calculation of the installed capacity of this table					

Table 27: Total RES installed capacity and percentage change (2016-2018)

In 2018, RES production in Greece amounted to 11,1 TWh in total, which was increased compared to 10,3 TWh in 2017, and represented a share of 20.4% of the total electricity consumption in the country.

	2013	2014	2015	2016	2017	2018
Biomass	210	206	222	253	280.3	297.97
Small Hydro <10MW	772	661	707	722	586.5	718.45
PV on roofs <10Kw	480	520	494	512	511.5	488.75
PV	3,168	3,458	3,409	3,418	3,480	3,304
Wind	4,139	3,757	4,621	5,146	5,515.4	6,300.26
Total (excluding large hydro)	8,769	8,602	9,453	10,051	10,373.7	11,109.43

Table 28: RES Generation excluding large hydroelectric plants (2013-2018) GWh

3.5.2. RES and the electricity Market

Until the full implementation of the target model, there is no intra-day electricity market in Greece (a precondition for the development of RES market). RAE in cooperation with the Ministry of Energy and all relevant stakeholders 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 are still not subject to standard balancing responsibilities.

3.5.3. RES projects' licensing

During 2018 there has been no amendments to the relevant legislative framework. RAE issued a total of 779 administrative acts and sent 133 letters for supplementary elements as part of the evaluation process. It is noteworthy that photovoltaics showed a remarkable increase in terms of applications received by RAE (around 1400% compared to 2017). The total number of licenses and the number of RAE decisions per category in 2018 are presented in the tables below.

Technology	No of Licenses	Capacity Power (MW)
Wind	1,096	22,639.30
PV	589	3065.8
Hydro (small)	404	908.8
Geothermal	1	8
Biomass	106	424.9
Solar	82	442.2
Hybrid	20	428.7
Co-generation (electricity & heat)	57	341.55
Total	2,333	28,070.96

Table 29: Projects with a license/permission of generation (non- operational) approved by RAE, end of year 2018

Technology	2017				2018			
	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	175	1,845.88	14	222.5	294	2,621.6	55	776
P/V	23	199.45	23	173.5	341	4,050.3	14	164
Hydro small	16	50,40	18	49.66	23	54.7	1	0.9
Biomass	6	14.87	9	19	5	15.3	12	55
Cogeneration electricity& heat	1	4	1	4.36	1	1.2	1	4
Hybrid	96	389.82	0	0	11	69.9	0	0
(Tele) heating	0	0	1	9,8	0	0	0	0
Total	317	2500,2	66	478.82	675	6,813	83	999.9

Table 30: Number of RES applications and number of generation licenses

3.5.4. RES 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 main change in the new RES support financial scheme is the abolition of the Feed in Tariff financial support mechanism for new RES projects, wind farms larger than 3 MW and other RES projects larger than 0.5 MW now receive operating aid based on the new mechanism of sliding Feed in Premium[12].

[12] Energy Communities are exempted from that rule. Specifically, wind farms up to 6 MW and PVs up to 1 MW, that are operated by Energy Communities, may still receive operating aid based on feed-in-tariffs

Renewable technologies and project categories	RT (€/MWh)	Project IRR
Onshore wind parks in the Interconnected System	98	9%
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%

Table 31: Reference Tariffs of Law 4412/2016, Table 1 of Article 4.1(b)

In fact, 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 inject into 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 DAPPEP, 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 DAPPEP and the opinion of the Greek Regulatory Authority for Energy. The duration of the Operating Aid is 20 years for all RES and HECHP technologies, apart from small rooftop PV installations up to 10 kW and CSP installations for which the duration is set to 25 years.

The auctioning procedure, which includes an electronic submission of applications and their evaluation by RAE followed by an electronic auction, is innovating, transparent, simplified, valid and reliable process, is regarded as best practice by many European countries. The innovative electronic procedure of bidding procedures on RES and CHP power plants was of the Yankee Reverse auction type and was conducted in two phases: online submission of the applications' supporting documents and conduct of the auctions on the same custom developed platform for all the relevant categories of the projects.

Early 2018 RAE's Opinion to the Ministry of Energy included the following 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:

YEAR	TECHNOLOGY	**Maximum Auctioned Capacity (MW)**
2018	PV	300 (July & December)
	WIND	300 (July & December)
2019	PV	300 MW (July & December)
	WIND	300 MW (July & December)
	PILOT COMMON COMPETITIVE PROCEDURES	400 MW (April)
2020	PV	Remaining capacity of PV technology of 2019 plus 300 MW
	WIND	Remaining capacity of Wind technology of 2019 plus 300 MW
	COMMON COMPETITIVE PROCEDURES	500 MW
Total Capacity to be auctioned between 2018 - 2020		2,700 MW

Table 32: Electricity Generation per Technology type and Auctioned Power

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.

In 2018, six (6) RES auctions were held in Greece:

Three competitive bidding procedures for RES projects were conducted on July 2, 2018 for three categories of projects as set out in RAE's Decision No. 321/2018. Specifically: The first auction was held for PVs with installed capacity of PPV ≤ 1MW, the second for PVs with installed capacity of 1MW < PPV ≤ 20MW and the third for onshore wind power stations with installed capacity of 3MW < PWIND ≤ 50MW. The maximum auctioned capacity for the first category was set at 70MW. The starting bidding price was € 85/MWh, while the Reference Prices ranged from € 75.87/MWh to € 80/MWh and the weighted average price was € 78.42/MWh. The final auctioned capacity operating aidin the first category amounted to 53.52 MW while the auctioned capacity that was granted operating aid was 53.48 MW. The maximum auctioned capacity for the second category was set at 230MW. The starting bidding price was € 80/MWh, while the Reference Prices ranged from € 62.97/MWh to € 71/MWh and the weighted average price was € 63.81/MWh. The final auctioned capacity that was chosen to receive operating aid in the second category was amounted to 53.40 MW while the auctioned capacity that was chosen to receive operating aid was 52.92MW. The maximum auctioned capacity for the third category was set at 300MW. The starting bidding price was € 90/MWh, while the Reference Prices ranged from € 68.18/MWh to € 71.93/MWh and the weighted average price was € 69.53/MWh. The final auctioned capacity for the third category amounted to 176.39 MW and the auctioned capacity that was chosen to receive operating aid was 170.93 MW.

The rest three competitive bidding procedures for 2018 for RES projects were conducted on 10 December 2018 for three categories of projects as set out in RAE Decision No. 1026/2018. Specifically: The first auction was held for PVs with installed capacity of PPV ≤ 1MW, the second for PVs with installed capacity of 1MW < PPV ≤ 20MW and the third for onshore wind power stations with installed capacity of 3MW < PWIND ≤ 50MW. The maximum auctioned capacity for the first category was set at 90MW. The starting bidding price was € 81.71/MWh, while the Reference Prices ranged from € 63/MWh to € 68.99/MWh and the weighted average price was € 66.66/MWh. The final auctioned capacity was 61.95MW while the capacity that was chosen to receive operating aid in the first category was amounted to 61.94MW. The maximum auctioned capacity for the second category was set at 100MW. The starting bidding price was € 71.91/MWh, while the Reference Prices ranged from € 63/MWh to € 71.91/MWh and the weighted average price was € 70.39/MWh. The results of the auction for the second category of projects, have shown a distortion of competition. This was caused fifteen projects who had failed to submit bids and consequently their non-participation in the competitive process which resulted in the manipulation of the results of the auction, in violation of the 75% rule for competition. For this reason, RAE with the Decision No 1230/2018 announced the cancelation of the auction for second category. The maximum auctioned capacity for the third category was set at 229MW. The starting bidding price was € 79,77/MWh, while the Reference Prices ranged from € 55/MWh to € 65,37/MWh and the weighted average price was € 58,58/MWh. The final auctioned capacity for the third category amounted to 160.94 MW while the capacity that was selected to receive operating aid was 159.65 MW.

The main conclusions of the RES Auctions in Greece can be summarized as follows:

- **The whole process was innovative, simplified, transparent, valid and reliable.**
- A specific online platform was modified according to the decisions of RAE.
- **Achievement of significant reduction in prices.**
- The minimum level of competition 75% drive to a significant reduction of the prices (July 2018 & December 2018)
- There were no problems understanding and using the applications during the users' training.
- The "virtual auctions" solved any questions about the procedure of the tenders.
- No mistakes in participants' registration process, procedure of application and suspension supporting documents in the online platform.
- The electronic submission of the applications → This made possible the immediate beginning of the evaluation of applications by RAE, by significantly reducing the time which would be required under any other conditions
- **Approximately 100% of the auctioned Capacity was covered according to the tender procedure**
- All selected candidates comply with the Rule of 4% about Performance Guarantees
- All the Projects connected to the grid according to the timetables of the proclamation.

3.5.5. RES Financing

Several instruments are in place to support the financing of RES, including a revenue from the operation of the day ahead market, a revenue from the market clearing and settlement procedures of the day ahead market, a revenue equal to the average variable cost of conventional Generation units (this is important especially for NIIS), a revenue from the energy cost a revenue for CO2 emission rights and Levy on CO2 emission of conventional generation units.

In 2016 RES account appeared an estimated deficit of 238.48 million Euro. However, in 2017 RAE with its decision on 22 December 2016 (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 and a surplus of 191.24 million Euro in the end of the year 2018.

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%

Table 33: RES Levy Change of Unit Pricing and percentage change (2017-2018)

	2017	2018
Total Revenue (in million euros)	2,132.91	2,020.61
Day Ahead Market	485.61	583.51
Market Clearing and Settlements	10.60	8.08
Average Variable Cost of Generation	21.96	54.91
Average Variable cost of generation (NIIs)	123.82	141.61
RES Levy (ETMEAR)	888.92	631.09
Energy Charge (Suppliers)	411.46	237.93
Levy on CO2	32.77	29.81
CO2 emission Rights	151.85	328.34
Other (licences fee)	-	-
Total Expenditure (in million euros)	-1,848.74	-1,871.87
Account Balance (end of year)	284.17	148.75

Table 34: RES' Financing Account (2017-2018)

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.

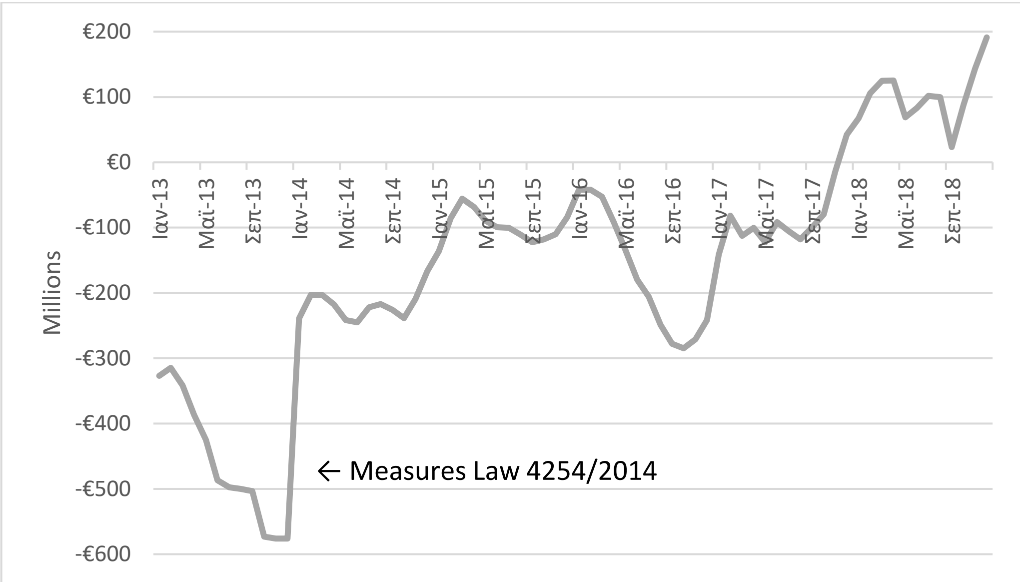


Figure 16: Special Account's Progress

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).

3.5.6. New RES legislation

There were three important legislative initiatives undertaken in 2018 as Law No 4512/2018, Law No 4513/2018 and Law 4585/2018 were adopted.

In the context of the reorganization of the Greek electricity market, in line with EU rules for the completion of a single European energy market, the Greek government adopted the Law No 4512/2018 in January 2018 which, inter alia, amended the Law 4425/2016. This law made a significant change in the structure and the operation of the Electricity Market Operator (LAGIE SA). Specifically, the law provided for a special procedure under which the Electricity Market Operator transferred its responsibilities for the operation of the existing energy market to the Hellenic Energy Exchange S.A.

(HEnEX S.A.). The responsibilities transferred to HEnEX S.A. include, inter alia, the following tasks: carrying out the DAS, scheduling electricity injections into the national electricity network as well as electricity absorptions and the calculation of the SMP. After the transfer of the responsibilities, LAGIE S.A. was renamed to Operator of RES and Guarantees of Origin (DAPEEP S.A.) and it is responsible, inter alia, for the conclusion of Operating aid contracts as provided under the Law No 4414/2016, the recovery of revenue from the contracting producers of RES and CHP power plants to cover its operating and investment costs, the submission bids for the amount of energy expected to be injected into the national electricity system by the Roof Photovoltaics network and the RES and CHP power plants under the provisions provided in the Article 12 of Law 3468/2006 and the Feed-in-Tariff operating aid contracts regulated by the article 10 of Law 4414/2016, as well as the management of the RES Special Account.

The law No 4513/2018 created a specific regulatory framework for the establishment and operation of the Energy Communities, with special emphasis on RES. In this regard, the Greek State gave particular incentives to Energy Communities such as the priority management of their applications for the production licenses and the environmental licensing of their projects. Certain categories of projects (wind and photovoltaic power stations, of Energy Communities were also exempted from the participation in competitive tenders. In addition, Energy Communities were exempted from the obligation to pay the annual fee to maintain their production license under the Law 4152/2013 and their guarantee fee obligation for the acceptance of the final/binding connection offer to the network was halved. Finally, power plants of installed capacity up to 1MW, operated by Energy Communities, may participate in the current Net-Metering scheme.

The Law 4585/2018 brought about the following significant changes in the field of RES:

The Paragraph 1(a) of Article 3 of the Law 4585/2018 waives the exemption of large photovoltaic power plants, over 20MW, to submit the special charge levy to RES producers, in the light of the two joint competitive tender procedures for wind and photovoltaic power plants. In addition, this special fee is also paid by Hybrid Power Plants which is charged on the revenue from the sale of electricity injected into the national electricity network or originated from the Controlled Hybrid Power Generation Units.

According to the provisions of the article 4 of Law 4585/2018, as of April 1, 2019, the responsibilities of IPTO S.A regarding the management of the revenues of the Special RES Account of the Article 143 of Law 4001/2011 related to the Special Emissions Reduction Fee (ETMEAR), the Average Weighted Variable Costs of Conventional Thermal Stations and the Special Lignite Fee are transferred to DAPPEP S.A. In addition, the Suppliers Charge (ΠΧΕΦΕΛ) that was charged to Electricity Suppliers as well as the Special Lignite Production Fee charged to lignite electricity producers will be abolished starting from January 1, 2019. Article 4 also sets forth the appropriate regulatory framework in order to put into effect the new scheme of reduced charges of ETMEAR starting from 1 January 2019 as required by the European Commission Communication on State Aid Guidelines for the Environment and Energy (2014 to 2020) (Official Journal of the European Union, 2014 / C200 / 01).

3.5.7. Other regulatory developments in RES

Hybrid stations in NIIs

In 2018, RAE concentrated its efforts in the finalization of a new tariffs framework to encourage the installment of hybrid stations in NIIs. To this end, with the assistance of an external consultant for the calculation of relevant cost, issued Opinion 7/2018 to the Minister of Energy in July 2018 with specific suggestions regarding the regulatory parameters of the new framework.

Total renewal of RES plants

RAE issued Opinion 6/2018 to the Minister of Energy pursuant to par. 19 and 22 of art. 3 of Law 4414/2016 with specific suggestions concerning the terms and conditions for the operation of renewed RES plants, following which the Minister issued decision 179746/02-10-2018 (OJ B' 4716/22.10.2018) in particular for wind parks.

Regulatory framework for the installation of RES plants from self-producers through net-metering and virtual net-metering

RAE submitted to the Minister of Energy Opinion 15/2018 regarding the completion of the regulatory framework for the installation of RES plants from self-producers through net-metering and virtual net-metering, to accommodate mostly for the new provisions of Law 4513/2018 for the Energy Communities.

Study for the development of offshore wind parks in the Greek seas

Acknowledging the high wind potential of the Greek seas, and in view of achieving the high RES shares in the national mix of electricity production, assigned in 2018 to an external consultant the production of such study, upon the main conclusions of which a feasibility study was then conducted.

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

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	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

are informed about their right of withdrawal when the notice is given		change. In any case, customers have the right to withdraw from the contract at no cost if they do not agree with the new terms.
Customers must receive transparent information on applicable prices and tariffs and on standard terms and conditions in respect of access to and use of electricity services.	c)	The Electricity Supply Code stipulates that contracts must contain a section which clearly summarizes the costs borne by customers for the supply of electricity.
Customers are offered a wide choice of payment methods.	d)	This obligation is derived from the Electricity Supply Code with the additional term that at least one payment method offered by each Supplier must be cost free
General terms and conditions shall be fair and transparent, and given in clear, comprehensible language. Customers shall be protected against unfair or misleading selling methods	d)	The Electricity Supply Code contains the minimum “Principles of information and contact with clients” that cover all the required obligations. Suppliers are obliged to introduce a Code of Contact based on at least the above referred principles.
Customers are not charged for changing supplier.	e)	Supplier switching is free of charge according to the Electricity Supply Code.
Consumers benefit from transparent, simple and inexpensive procedures for dealing with their complaints.	f)	The Electricity Supply Code stipulates that Suppliers must operate a Consumer service department that handles customer complaints according to at least the minimum “Standards of complaints handling” included as a separate section of the Code. Written complaints / enquires must receive a first or final response within 10 working days.

Consumers benefit from information about their rights regarding universal service (electricity customers) of their right to be supplied at reasonable prices	g)	The relevant information for consumers can be found on the Authority's website (www.rae.gr)
Consumers can have at their disposal their consumption data and shall be able to allow any registered supply undertaking to access, by explicit agreement and free of charge, their metering data	h)	Consumers are adequately informed of actual consumption, quarterly or every four months through their bills. In addition, an application form is available at their Supplier's site and/or customer service centers, to request for historical consumption data.
Consumers receive a final closure account following any change of supplier, no later than six months after the change of supplier has taken place.	j)	Energy Suppliers are obliged to issue a final closure account, within 6 weeks after the contract termination/change of supplier.
PARAGRAPH 2		
Member States shall ensure the implementation of intelligent metering systems that shall assist **the active participation of consumers in the electricity and natural gas supply markets**		In the electricity sector, the timeframe for the roll-out of smart meters is set by Law no. 4001/2011 for the replacement of at least 80% of old meters by 2020.

Table 35: State of implementation of measures set out in Annex 1 (Directive 2009/72/EC)

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 - The Price Comparison Tool (PCT)

On the basis of European practice, principles of transparency, accessibility to information, independence and consumer protection, the consumers should be able to choose Suppliers of electricity and gas on the basis of objective and comparable data on the services they offer in order to the best choice for them. These choices can be ensured by the creation of a comparison tool, an internet application, that will enable the proper monitoring and comparison of the products offered by the Suppliers and the retail energy market prices (electricity and gas).

These can be ensured by creating an independent price comparison tool, i.e. an online application of special purpose that monitors and compares the prices and the products of the retail energy markets (electricity and natural Gas). This price comparison tool is intended to facilitate the provision of information and to allow final consumers, as far as feasible, to independently assess the cost of the supply and the choice of supplier.

This effort is also part of the monitoring of the functioning of the retail market and the better information of consumers and is in line with the requirements of Directive 2009/72/EC and of the guidelines specifically adopted on this subject (Guidelines of Good Practice on Price Comparison Tools, Ref: C12-CEM-54-03 10 July 2012). According to the guidelines, the creation of an energy price comparison tool is a good practice and an important means of transparency of consumer transactions with electricity and gas providers, which enhances healthy competition in the energy sector and is vital for the further development of European energy markets.

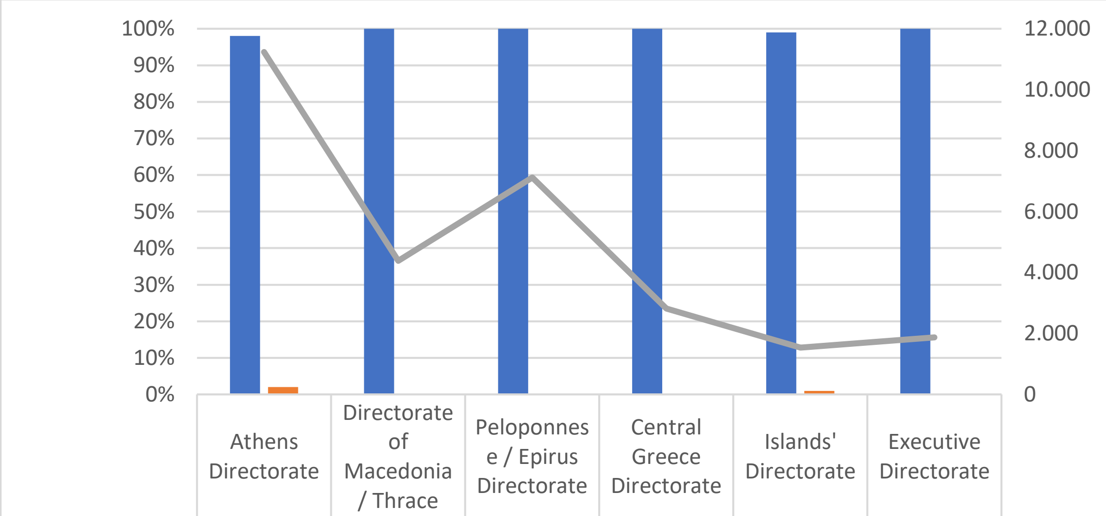
RAE in the context of its competences, under the provisions of articles 22-24, 27 and 49 of law 4001/2011 and article 7 of the supply codes to customers (for gas GAZETTE B ' 1969/2018 and for electricity FEK Β΄ 832/2013 respectively, as applicable) and, taking into account the provisions of Directive 2009/72 and the guidelines, focused on the creation of a fully functionable a price comparison tool for electricity and gas, which started as a process in the last quarter of 2018 and is expected to be completed after the end of the 2nd semester of 2019.

In fact, RAE is developing a web application in order to monitor and compare all the available products of the Retail Energy Markets (electricity and natural gas). This application is separated in three distinct areas and entities: a) Area A: Consumers’ portal (Observatory), A public access area, where consumers can be informed for all the available data offered by suppliers, b) Area B: Suppliers’ portal (Repository), Suppliers’ registration/identification and data entry area, c) Area C: Admin area, An internal/intranet area, where Regulator can monitor and manage areas A & B.

This tool is designed to reflect and compare as fully as possible, on the basis of the principles of transparency, accessibility, completeness of information and independence in updating, the overall estimated cost of the Competitive part of the invoices offered, while also calculating the corresponding cost of the regulated strand related to consumption and use of energy. This price comparison tool is targeted to the electricity low-voltage small customers, and domestic and commercial customers of natural gas as defined in article 3 of the respective supply codes.

3.6.4. Quality of DSO Services

Another key direction of RAE was related to the improvement of the customer services of the electricity DSO.

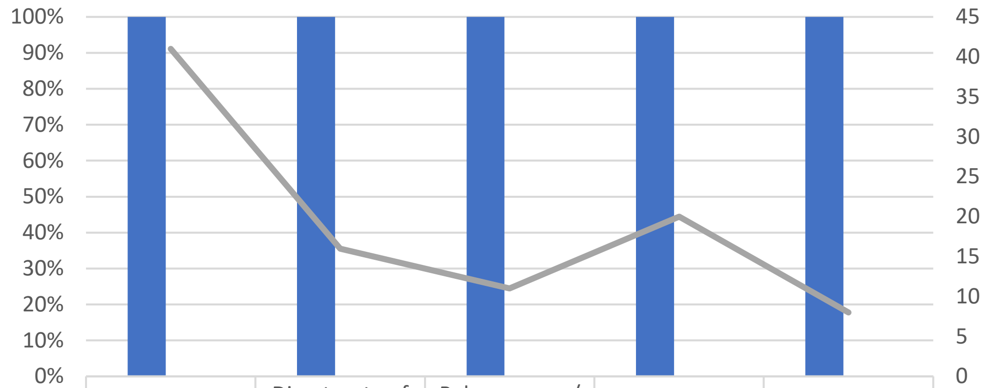


	Athens Directorate	Directorate of Macedonia / Thrace	Peloponnese / Epirus Directorate	Central Greece Directorate	Islands' Directorate	Executive Directorate
In-time	98%	100%	100%	100%	99%	100%
Delayed	2%	0%	0%	0%	1%	0%
Total	11.237	4.381	7.113	2.819	1.536	1.875

Figure 17: Response to Guaranteed Consumer Services by HEDNO (2018)

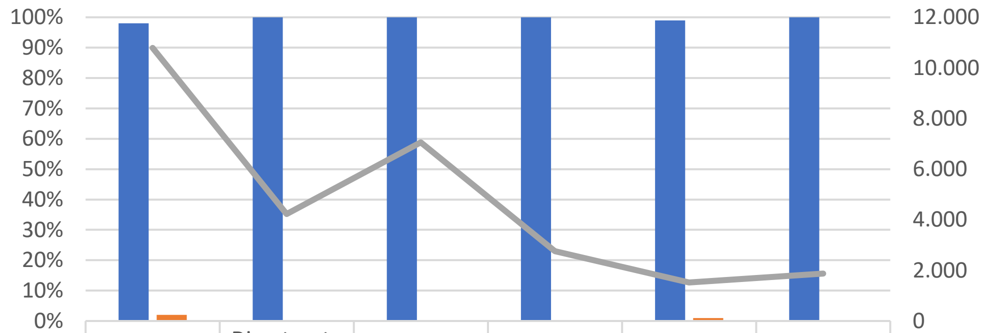
As shown in the Figure above, the DSO reacts within the set periods up to a satisfactory level. However, RAE, in cooperation with the DSO, has already prepared for the further upgrading of the guaranteed services in order for more crucial services to be included within them such as the installation of night time meters etc., and further to implement a system of gradual monetary restitution in cases of important diversions from the set timelines.

In particular, the results per category of the Guaranteed Services for 2018 is depicted in the Figures below:



	Athens Directorate	Directorate of Macedonia / Thrace	Peloponnese / Epirus Directorate	Central Greece Directorate	Islands' Directorate
In-time	100%	100%	100%	100%	100%
Delayed	0%	0%	0%	0%	0%
Total	41	16	11	20	8

Figure 18: Response to complaints concerning voltage quality by HEDNO (2018)



	Athens Directorate	Directorate of Macedonia / Thrace	Peloponnese / Epirus Directorate	Central Greece Directorate	Islands' Directorate	Executive Directorate
In-time	98%	100%	100%	100%	99%	100%
Delayed	2%	0%	0%	0%	1%	0%
Total	10.790	4.227	7.055	2.761	1.522	1.872

Figure 19: Response to complaints or requests without the need for an on-spot transition by HEDNO

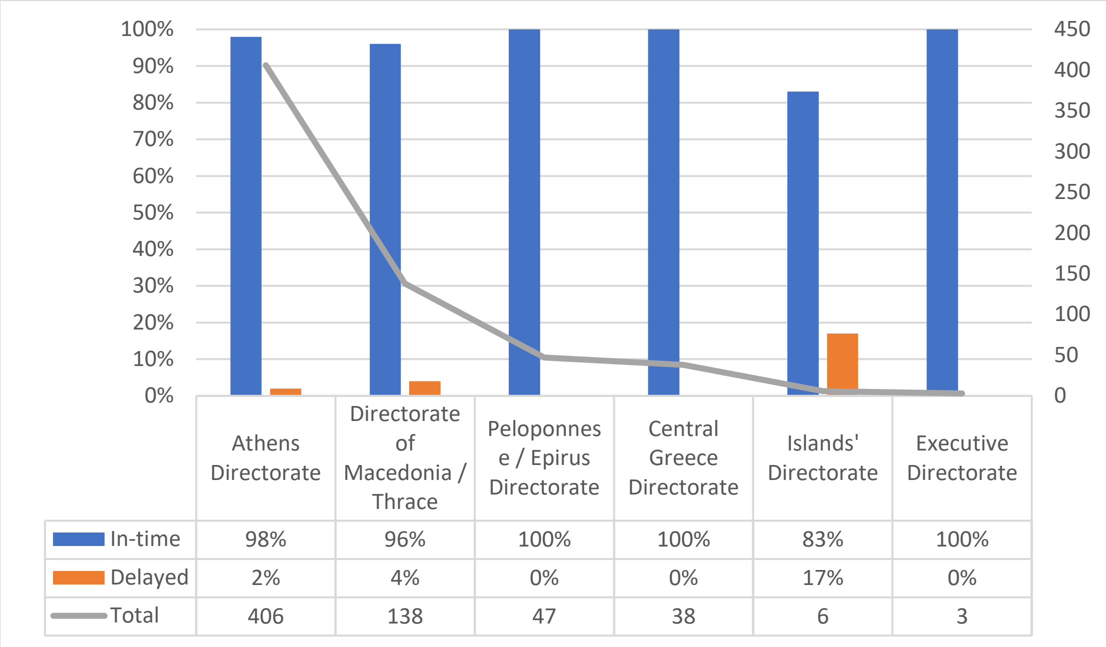


Figure 20: Response to a request with the need for an on-the-spot transition by HEDNO (2018)

3.6.5. Vulnerable customers and Energy poverty

In 2018, the ministerial decision published in the Government Gazette B '242 / 01.02.2018 amended the categories of the beneficiaries of the Residential Social Tariff (KOT), the criteria for its application and the discount granted.

	Residential Social Tariff 2011 - 2018		**Economic crisis Program**	
Year	Number of customers	Total Energy (TWh)	Number of customers	Total Energy (kWh)
2011	247,666	548		
2012	250,568	404		
2013	412,883	1,582		
2014	522,760	1,251		
2015	656,834	1,315	70,002	232,886,076
2016	578,311	1,549	46,562	244,020,079
2017	693,487	1,651	NA	NA
2018	471,706	0,999	NA	NA

Table 36: Number of customers and total consumption - Residential Social tariff 2011 – 2018

3.6.6. 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.

RAE also has on its website an online form for consumer complaints and enquires which can be filled and automatically sent to RAE together with all necessary attachments.

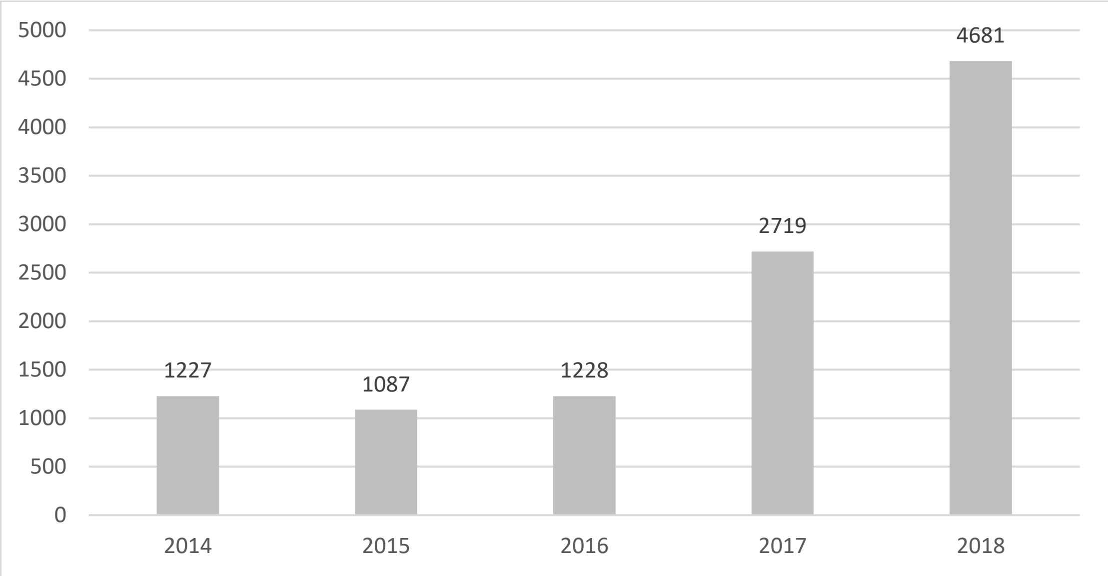


Figure 21: Consumer Complaints submitted to RAE (2014-2018)

The total number of reports submitted to the Authority in 2018, amounted to 4681, significantly increased (by approximately 72,15%) compared to 2017, reaching the highest level of the last decade. The activation of many 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.

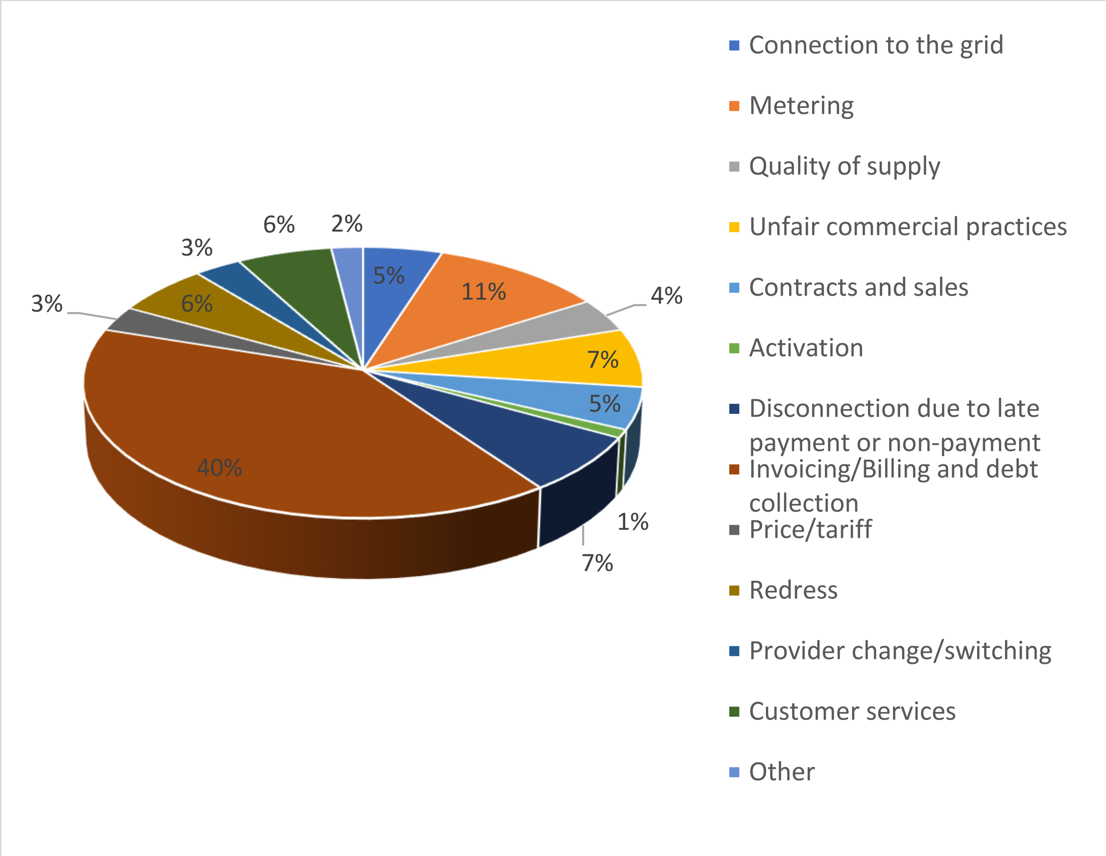


Figure 22: Total Number of consumers' complaints (Electricity)

In 2018 there is a relative reduction in complaints about consumption meters in comparison with the data from 2017 (from 18.5% to 11%). For many years, the main subject of complaints remains the analysis and explanation of the consumption bills (40%) even though this percentage was lowered compared to 2017 where the complaints about consumption bills were around 50% of the total number.

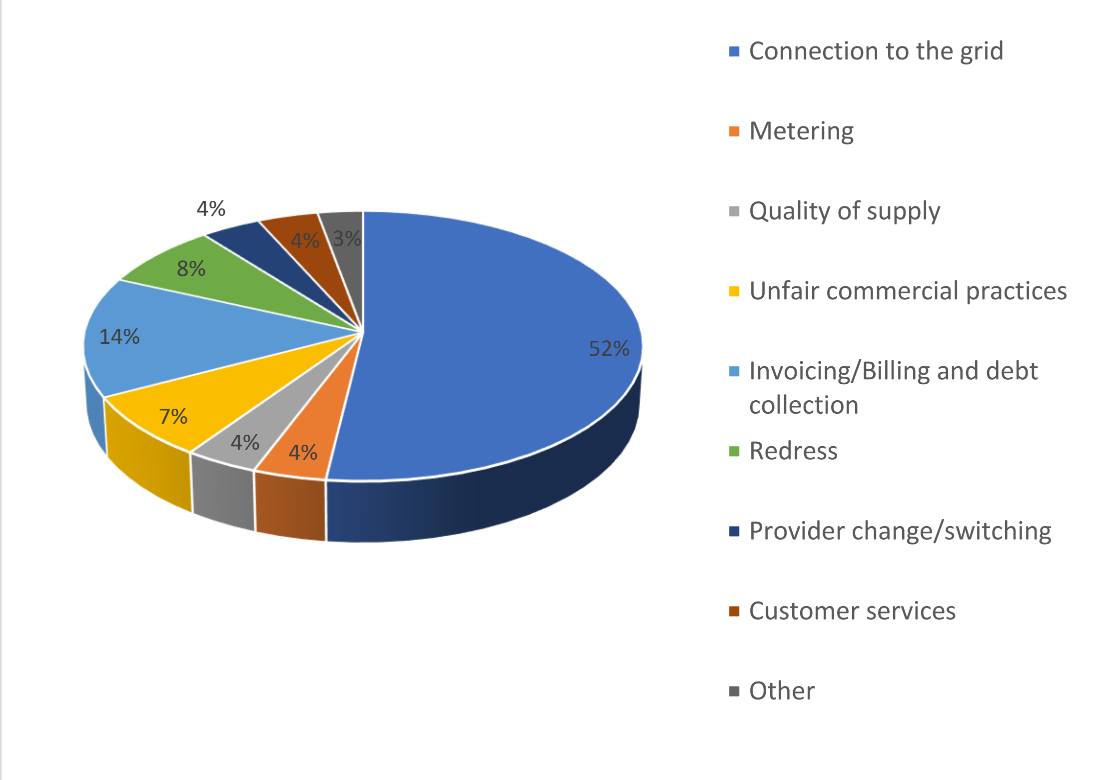


Figure 23: Total Number of consumers' complaints (Gas)

For the first time in 2018 RAE introduced a weighted index for the number of consumer complaints per supplier, based on the market share of each supply company and the number of complaints received by the company and in total.

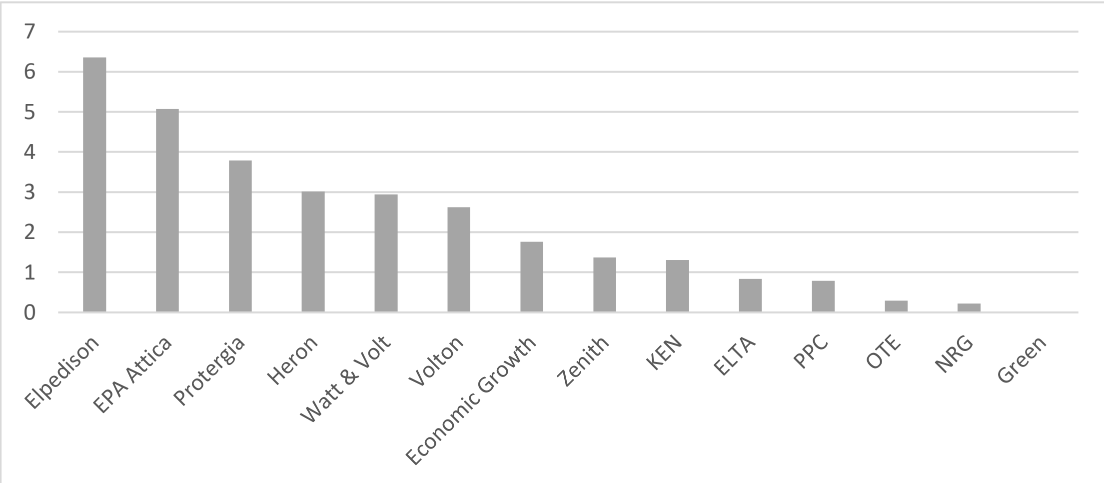


Figure 24: Weighted Complaint Index per Supplier (2018)

3.6.7. 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.

3.6.8. Regulatory Decisions and Opinions of RAE

RAE Opinion No 16/2018 on the reform of the Services of general interest for the nighttime consumption

The legislative framework concerning the "Services of general interest" charges in nighttime electricity consumption changed from 1 January 2018 (Government Gazette A 200/22.12.2017), both in terms of the unit charges and the method of calculating the charges. In particular, the new calculation method provided for tiered charges depending on the energy consumed in each tier, while the previous calculation method had provided for charging all the energy consumed based on the unit price of the tier that it belonged. The introduction of tiered charges in the "Services of general interest" is compatible with the Directive 2012/27/EU on Energy Efficiency and Law 4342/2015 which transposed the above Directive into national law, as they are a clear incentive for energy savings and energy efficiency. The new nighttime consumer charges have slightly reduced the burden of the "Services of general interest" to the lower tier, in which most consumers belong. Compared to the previous charging scheme, the consumers that had a nighttime consumption of over 1,700kWh had a disproportionate burden due to the introduction of that tiered charge.

RAE, following the implementation of the above charging regime, received many complaints from both consumers and various consumer organizations about the "Services of general interest" excessive nighttime charges since most of the consumers fell into the two largest billing tiers.

After taking into account the status of the "Services of general interest" account, as well as the income recovered from the nighttime consumption, it provided an opinion to the Minister of Energy (Opinion No 16/2018 on "Reforming the framework of Services of general interest for the nighttime consumption"), for the reduction of the "Services of general interest" charges for the nighttime consumption in order to rationalize the charges on the households. Furthermore, RAE advised for the above charges to have a retroactive effect from 1.11.2018 in order to cover the 2018-2019 winter season.

Opinion No. 10/2018 on the imposition of maximum selling prices of petroleum products pursuant to Law 3054/2012

With the no. 79056 / 23.07.2018 (RAE I-243313 / 23.07.2018) letter from the Secretary-General of Commerce & Consumer Protection, RAE was called to give an opinion regarding the possibility for the imposition of a ceiling price on petroleum products in the Dodecanese. RAE, within its competence, and in particular as set forth in paragraph 2 of section 20 of Law 3054/2002, given the significantly higher prices of petroleum products at a large number of petroleum stations in certain municipalities of the country compared to other municipalities and especially the region of Attica, in combination with the general economic situation of the country, after receiving appropriate petroleum pricing data from the Ministry of Development, considered it appropriate to take measures in order to avoid market distortion and risks to healthy competition caused by certain parties that could exploit the current regime and set the retail prices of petroleum products that were not based on real costs. For the above-mentioned reason, RAE gave a positive Opinion to the Minister of Energy and the Minister of Economy and Development (No. 10/2018) on the imposition of maximum prices on the sale of petroleum products to consumers in certain regions of the country that met specific criteria and a detailed methodology, that were set in the same opinion, in order to be included in the regime. RAE also referred the matter to the Competition Commission for potentially further actions.

Regulatory intervention for the proper implementation of the Residential Social Tariff (KOT) and the Humanitarian Crisis Program

In 2018, RAE received consumer complaints for the way the Residential Social Tariff in conjunction with the Humanitarian Crisis Program was implemented in practice by the supply company WATT & VOLT S.A. In this context, the Authority identified the need for a proper implementation of the two schemes in combination with each other and subsequently it made a suggestion to the company, which fully cooperated. The result of this regulatory intervention was the return of 42.000€ to the affected consumers.

Consumer abusive behaviour in overdue electricity bills and its handling by RAE

RAE within the scope of its competencies, is responsible to monitor the internal energy market. In 2018, following letters of Suppliers' to RAE on increasing cases of abusive behaviour of consumers who, in order to avoid paying their obligations to their Supplier apply for a succession of their connection to an affiliate or a family member either with a new supply contract with the same Supplier or by switching to a new Supplier. The critical issues that have arisen are identified in cases where the debt contract provision to deactivate the connection was not activated or where the connection deactivation order was not submitted to HEDNO, in which case the latter was not informed about the existence of the debt in order to prevent the switching of the Supplier. RAE cooperates extensively with the DSO and other entities in order to ensure the compliance with Article 42 of the Supply Code to cancel the succession of a consumer's contract in case there are any outstanding debts towards its Supplier.

In 2018, RAE by considering all the existing information, proceeded with a letter to all Suppliers, to the correct interpretation and application of the Article 42 (2) of the Supply Code. In particular, it recognised the ability of the consumer with overdue debts to switch its Supplier after the termination of the Supply Agreement with the old Supplier, pointing out that, in this way, the consumer is not exempted from his obligation to repay his debts that have arisen from the old contract, in accordance with Article 47 of Law 4001/2011 and Article 42 (4) of the Supply Code. Also, RAE, established the right of the old Supplier to request the deactivation of the consumer's connection in the event that no debt settlement agreement was reached between them even after the termination of their supply contract and a new contract with a new Supplier, pursuant to Article 42 (1) of the Supply Code. Furthermore, RAE examined but ultimately didn't establish the possibility of a limited time period deactivation of the consumers' connection with overdue debts.

Regulatory interventions concerning the Supplier of Last Resort and the Universal Service Provider

RAE, in 2018, as required by law, invited all interested Suppliers to participate in a tender in order to provide Services of General Interest under the Supplier of Last Resort and the Universal Service Provider model for a period of three years (23.03.2018 – 22.03.2021). The deadline for submissions expired without any expression of interest. Accordingly, the two relevant tenders were declared barren under RAE Decisions No 1089/2017 and No 1090/2017. In the first quarter of 2018, following the procedure described in Articles 57 and 58 of Law 4001/2011, regarding the designation of the largest market share per customer category Supplier, as the Supplier of the Last Resort and the Universal Service Provider for the period 23.03.2018 – 22.03.2021, RAE, with its Decisions 240/2018 and 241/2018 (Government Gazette B 1148 / 29.03.2018) appointed PPC as the Supplier of the Last Resort and as the Universal Service Provider.

The Universal Service is provided to the consumers, in accordance with the provisions of Article 58 of Law 4001/2011 and Article 44 of the Electricity Supply Code, without any time restrictions to the provision of the Service. RAE, in the context of dealing with abusive consumers' behaviours and the abuse of the Universal Service Regulations and the data provided by PPC as the Universal Service Provider, considered it necessary to advice the Minister of Environment and Energy to modify the relevant legislature framework governing the provision of this Service. The recommendation concerned an amendment of the Article 52 of Law 4001/2011 that introduced a maximum limitation of three months stay on this Service for the consumers in order to give them appropriate time to negotiate a new contract with the Supplier of their choice but also to tackle any abusive consumer behaviour during the utilisation of the Universal Service.

Furthermore, considering that the retail gas market differs from the electricity market, as the activity of the Gas Suppliers is linked to both geographical data and consumption characteristics (commercial, industrial and household consumers), it was considered that the provisions governing the "Electricity Supplier of Last Resort" do not meet the specifics of the natural gas market. Therefore, in the light of the conclusions reached, RAE highlighted, to the Minister of Environment and Energy, the importance of drafting the relevant legislative framework which will complete the current legislation that governs the Supplier of the Last Resort of the natural gas market.

4. Regulation and Performance of the Natural Gas Market

4.1. Network Regulation

4.1.1. Unbundling

A) TSO Unbundling

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 2018, according to the provisions of paragraph 4 of article 64 of Law 4001/2011, DESFA SA announced to RAE the sale of 66% of its share capital in the joint venture of Snam S.p.A, Enagas Internacional S.L.U. και Fluxys S.A. In fact, in July 2018 DESFA S.A. applied to RAE for a new certification this time under the model of Ownership Unbundling.

Following the assessment of DESFA's application, RAE issued its first certification Decision No. 767/2018 with which DESFA S.A. was preliminarily certified under the model of ownership unbundling as it is defined in Law 4001/2011 ensuring de jure and de facto compliance with the requirements of Article 9 and 10 of Directive 2009/73 and Article 62 of Law 4001/2011. Subsequently, the Authority, taking due account of the opinion of the European Commission and following a thorough analysis, with its final Decision 1220/2018 (Government Gazette B '5740 / 19.12.2018) certified DESFA S.A. under the model of ownership unbundling. The Decision established the compliance framework of DESFA S.A. and it specifically included that any breach of national or EU law or the conditions set under the Ownership Unbundling model would dead to a revision of the certification decision.

In December 2018, 66% of DESFA's shares were transferred to Senfluga S.A., with the Government of Greece holding the remaining 34% of its shares.

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.

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 are eligible as of 1/1/2018, a measure that contributes to the full opening of the retail market.

Following the unbundling of distribution activities from the supply of natural gas, according to the provisions of Law 4336/2015, the three new natural gas distribution companies (EDA Attikis, EDA Thessalonikis and DEDA) submitted requests to RAE for the issuance of a natural gas distribution license and natural gas operation license. RAE evaluated the applications of the above companies and approved their licenses after the amendment of the Natural Gas Licensing Regulation in 2018. The approved five-year Distribution Development plans were included in the Decisions No 1314/2018, 1316/2018 and 1318/2018 of RAE that approved the distribution licenses of those three companies.

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

Sidirokastro (Greece Bulgaria border)	34,746,416	65.9%
Kipi (Greece - Turkey border)	7,159,338	13.6%
Agia Triada (Greece - Revithoussa border)	10,834,137	20.5%
Total	**52,739,891**	**100%**

Table 37: Natural gas import deliveries to the interconnection points (borders) Greece, in 2018 (MWh)

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 through the balancing platform, 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 1210/2018 (OJ B 5892/2018), RAE approved the annual balancing plan submitted by DESFA S.A. to the Regulator for the year 2019, which included TSO's estimated balancing the network natural gas needs as well as an evaluation of possible balancing gas supply sources for 2019. 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 2019, TSO estimated that the balancing natural gas needs will be recorded to 2% 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 also responsible for approving the balancing costs and the methodology for allocating these costs to the Transmission System users. With its Decision 486/2018, 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 2017. Furthermore, with its Decision 1119/2018, RAE approved the parameters that are involved in the calculation of the balancing gas cost for the year 2018. 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.

Regarding the application of the European Network Code on Balancing 312/2014 (NC on BAL), 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 above Network Code, 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.

Moreover, on 31 January 2018, RAE issued Decision 123/2018 with which it approved the 4th amendment of the Gas Network Code (Government Gazette B' 788/7.3.2018). The main arrangements of the 4th amendment concern the following issues:

A) Operation of the Balancing Platform in which the TSO will execute, based on market mechanisms, the purchase and sell of the required natural gas for load balancing of the national gas system.
   The Balancing Platform gives both the TSO and the users the ability of functional balancing in the national gas system, reducing in this way their imbalance charges. Furthermore, it provides the balancing ability through market mechanisms and not just a plain contract with one or more Suppliers (which is now only activated as the last option of the TSO in the case that the market fails to meet the functional balancing needs of the System. Finally, the Balancing Platform provides a price signal on the Greek market, thus it shapes the conditions for the creation of an organized gas hub in the country in the near future.

   Users are now responsible for balancing their portfolio on a daily basis through the submissions of Statements, Reports and Trade Notices, while the TSO is responsible for the residual balancing. The balancing operations that the TSO can perform are now based on merit order: 1. Purchase / Sale of balancing gas in the form of Short Term Standardised Products through market mechanisms (auctions) available in the Balancing Platform. Depending on the operational needs of the Natural Gas System for balancing, a maximum of one day-ahead (single-round, pay as bid) and eighteen within-day auctions may be carried out. 2. Through "Contractual Balancing Services", only in the event that the Short Term Standardised Products is not possible or is insufficient for the functional balancing of the System.

   Therefore, the Balancing Platform is a Short-Term Standard Products trading platform and one of traders is always the TSO.

The Balance Clearing Account includes any income or expense from the balancing process, while individual charges to the Users are annulled (recovery of balancing costs, balancing fixed asset balancing contracts). The Balance Clearing Account is cleared on a monthly basis.

The Balancing Platform determines the Marginal Daily Buying Price and the Marginal Daily Selling Price of balancing natural gas to settle the Daily Imbalances of the Users (Article 68 of Law 4001/2011 as amended by Law 4513/2018). The details of the daily imbalances were included in the “Balancing Manual”, which was approved by RAE’s Decision No 546/19.6.2018 (Government Gazette B 2523 / 29.6.2018), upon the recommendation of the TSO.

B) The creation of a Virtual Trading Point (VTP) in which the System Users can purchase and/or sell quantities of gas without having to reserve capacity for it. The VTP replaces the old Virtual Nomination Point (VNP) where only Users that had bound capacity in the System. A scheme for conducting transactions in the VTP with a parallel notification to the TSO is established. The VTP access service will now be included as a separate service provided by the TSO in the Standard Framework Agreement for Transmission of natural gas. The VTP operation is seen as a crucial step to increase liquidity in the natural gas market.

C) The auctioning of intraday Firm Capacity Products at Interconnection Points, completes the range of Auctioned Standardised Products to be provided by the TSO, in accordance with the European Capacity Allocation Regulation, enabling, in this way, the Users to temporarily reserve capacity within a specific day of gas flow until the end of that day and therefore exploiting every possible chance of cross-border trade. This provision entered into force with the amendment of the 4th amendment of the Gas Network Code, in which the starting bid price for intraday products was set.

Furthermore, with the same Decision No 123/2018 of RAE, it was decided to apply the process of capacity allocation, in accordance with the provisions set in Regulation (EU) 2017/459 of 16 March 2017 on establishing a network code on capacity allocation mechanisms in gas transmission systems, at the “Kipi” entry point from a third country (Turkey) and therefore it does not automatically fall within the scope of this Regulation, but it may be subject to a decision by the competent Regulator. Consequently, on the Greek side of the “Kipi” point, the capacity reservation is now made through the auctions of the Regional Booking Platform (RBP) and the first-come, first served rule is abolished, with the proper amendments to the Gas Network Code.

Finally, with RAE’s Decision 507/2018 (Government Gazette B '2473 / 27.6.2018), there was an amendment to the Standard Framework Agreement for Transmission of natural gas, which is concluded by the TSO and the Users that are registered in the NNGTS User Registry, in order for them to act as System Users. The operation of the Balancing Platform and the VTP required the adaptation of the Standard Framework Agreement for Transmission of natural gas as:

A) The TSO had to provide the new service in the VTP. The User wishing to be active in the VTP shall submit an Access Application under the Article 20K of the Code. The Application states the date of commencement of the service and it has indefinite duration. In order to provide VTP Access Services, the User must pay a guarantee equal to € 100,000, which is the lowest threshold established for the guarantee.
B) With the start of operation of the Balancing Platform, the Daily Imbalances Settlement is now based on the prices that result from the trading on the Platform (Marginal Buying Price and the Marginal Selling Price of balancing natural gas), as it is defined in the Gas Network Code

and the “Balancing Manual”. Therefore, the basis for calculating the guarantee, as it is set out in the Standard Framework Agreement for Transmission of natural gas, that the Users must pay to the TSO for the balancing service, was adjusted accordingly.

	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
61	VOLTERRA S.A.	Natural Gas Supplier
62	SINTEZ GREEN ENERGY CYPRUS LTD	Natural Gas Supplier
63	ELINOIL Hellenic Petroleum Company S.A.	Natural Gas Supplier
64	EFA Energy S.A.	Natural Gas Supplier
65	KEN S.A.	Natural Gas Supplier
66	Kavala Oil S.A.	Eligible Customer
67	MET ENERGY TRADING BULGARIA EAD	Eligible Customer

Table 38: Companies officially registered as NNGS users

DESFA's TYNDP

RAE with Decision No. 1086/2018 approved the Ten-Year Development Plan under specific conditions and called on DESFA to resubmit the Final Development Plan under the terms of the Decision. The consistency of the NDP was checked against both the regional and the European TYNDP.

4.1.3. Network and LNG Tariffs for Connection and Access

A. Transmission System and LNG terminal access tariffs

In 2018, RAE held a public consultation on DESFA's proposal regarding the 3rd amendment of the gas transmission tariff regulation, in accordance with the provisions of Regulation (EU) 2017/460 on the establishment of a network code on harmonised transmission tariff structures for gas.

The most important amendments concerned: A) The merge of System Exits (ie the Northeast, North and South Exit Zones) into a single Exit Zone, modification that allows the methodology to be characterized as "postage stamp". B) The calculation of the Allowed Revenue, as the sum of 50% of the Required Transmission Revenue and any (new) Recoverable Difference of those Revenues. C) The calculation of the Allowed Expenditure, as the sum of 50% of the Required Transmission Income, of any (new) Recoverable Difference of those Expenditures, the amount of the socialization of the Required Revenue of the LNG facility at Revithoussa. D) The recovery of Allowed Revenue of Incomes and Expenditures, minus the sum of the Old Recoverable difference, in full, from capacity-based transmission tariffs. The amount that is referenced in the Old Recoverable Difference is recoverable in full, from commodity-based transmission tariffs. Under the current Pricing Regulation, the allocation between capacity and quantity is 80% - 20% for all the above cases.

The revision of the tariff regulation was completed in 2019 (Decision 539/2019), after a second Public Consultation and taking into account ACER Report for Greece. The decision for transmission tariffs according to the new tariff regulation (566/2019) will be in force from 1.1.2020.

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

Transmission System for each Entry and Exit	MMSi$_i$ (€/kWh GCV /Day/Year)	TQEi$_i$ (€/kWh GCV)
Entry Sidirokastro	0.1920327	0.0001566
Entry Kipi	0.1919085	0.0001648
Entry Ag. Triada	0.0531502	0.0000673
Exit Northeast Zone	0.2864327	0.0003219
Exit North Zone	0.2750764	0.0003140
Exit South Zone	0.4870562	0.0005833
LNG TARIFFS	LCE (€/kWh GCV /Day/Year)	LQE (€/kWh GCV)
LNG Facility	0.1379529	0.0001746

Table 39: Natural Gas Transmission Tariffs coefficients for the Year 2018

B. Distribution System access tariffs

In 2016, RAE approved the gas distribution tariff regulation (RAE's Decision 328/2016) which provided the methodology for calculating gas distribution tariffs for the distribution system operators (covering a regulated period of 4 years, starting in 2017). The calculation of the regulated tariff is based on the methodology of the Allowed Revenue [Allowed Revenue = Allowed Return on the Regulated Asset Base + Annual Depreciation of Assets + Operating Costs – Other Revenue + Any Under / Over Recovery].

Total WACC (nominal, pre-tax)	9.23%
Market Risk Premium	5.23%
Beta	0.42%
Gearing (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%

Table 40: Main parameters of WACC- Gas Distribution 2018 (Decisions 345,346,347,348 /2016)

In 2018, the distribution tariffs of 2017 were adjusted based on the annual Consumer Index, as per the Distribution Code provisions, which at the end of 2017 amounted to 1,011%. Therefore, the regulated distribution tariffs of 2018 were the following:

	Attica	Thessaloniki	Thessaly	Central Greece	Corfu	Central Makedonia	Eastern Macedonia-Thrace
Pricing	**Capacity charges €/MWh/h (2018)**						
Households	1,122.31	450.06	521.74	1,229.37	0.00	791.16	546.44
Commercial	1,122.31	450.06	521.74	1,240.70	0.00	828.81	597.20
Industrial	4,521.80	1,800.46	2,087.24	7,279.12	5,789.12	4,561.53	4,865.53
A/C, Cogeneration	1,121.67	0.00	0.00	0.00	0.00	0.00	0.00
	Energy charges €/MWh (2018)						
Households	14.40	11.87	12.94	13.44	0.00	11.57	11.84

Commercial	14.40	11.87	12.94	11.34	0.00	7.53	7.34
Industrial	0.69	0.29	0.35	0.56	1.18	0.42	0.49
A/C, Cogeneration	3.78	0.00	0.00	0.00	0.00	0.00	0.00

Table 41: Capacity and energy charges per distribution network per pricing category

4.1.4. Cross-border issues

During 2018, the total natural gas deliveries at NNGTS entry points amounted to 52.45 TWh compared to 53.57 TWh in 2017, 43.8 TWh in 2016 and 32.9 TWh during the year 2015. Sixty six percent (66%) of total deliveries came from the interconnection point “Sidirokastron”, fourteen percent (14%) from the interconnection point “Kipi”, and twenty (20%) percent from “Agia Triada” (including LNG for balancing purposes).

Until recently, there was no considerable competition in imports of natural gas in Greece, as the share of DEPA gas imports corresponded to more than ninety percent (90%) of total annual imports. However, this has recently changed considerably. In 2018, with the provision also of intra-day but also physical reverse flow products in the Kulata – Sidirokastro interconnection point, the total share of DEPA dropped to seventy one percent (71%). More companies beyond DEPA imported gas with their share adding to the remaining twenty four percent (29%) of total imports.

With the 4th Amendment of the Natural Gas Network Code, RAE, after TSO’s proposal, decided to apply the capacity allocation procedure in accordance with the provisions of the Regulation (EU) 2017/459 of 16 March 2017 on establishing a network code on capacity allocation mechanisms in gas transmission systems, at the “Kipi” entry point from a third country (Turkey) and therefore it does not automatically fall within the scope of this Regulation, but it may be subject to a decision by the competent Regulator. Consequently, on the Greek side of the “Kipi” point, the capacity reservation is now made through auctions and the first-come, first served rule is abolished. In this framework, pursuant to RAE Decision No. 747/31.07.2018 (Government Gazette 3810/04.09.2018) on "Auction Procedure for Bidding and Allocation of Capacity at the Kipi Interconnection Point", DESFA announced in August 2018 the launch of auctions at the Regional Booking Platform (RBP) for the Kipi Interconnection Point. The first results of the capacity auctions were encouraging as well as other Users besides the dominant player, have already booked capacity and imported gas, for the first time, from Turkey.

The IGB pipeline

The Regulatory Authorities of Greece and Bulgaria have worked together from July 2017 to May 2018 to form a Public Opinion and draft a joint text (“Joint Opinion of the Energy Regulators on the Exemption Application of ICGB AD”) which contained the necessary terms and conditions for the grant of the exemption. The text was approved by the two Authorities with their Decisions 483/2018 (RAE) and R-VO-1/2018 (EWRC) on 29 May 2018. Their Joint Decision was forwarded to the European Commission, which adopted the Decision C(2018 5058 final “on the exemption of the Interconnector Greece Bulgaria from the requirements regarding third party access, tariff regulation and ownership unbundling” as set out in paragraph 9 of Article 36 of the Directive, requiring Regulators to make minimum adjustments.

RAE and EWRC further cooperated to amend their joint decision to be in line with the Commission's Opinion and issued the final Exemption Decision in August 2018, Decision 768 / 06.08.2018 (Government Gazette 4052 / 17.09.2018) and EWRC P-BG-2 / 08.08.2018.

Pursuant to article 4.3 point 1 of the Final Exemption Decision, ICGB AD was obliged, not later than 3 months from the adoption of the decision, to submit for approval to the Regulatory Authorities a final tariff methodology (IGB Tariff Code), which they did in November 2018. The Tariff Code proposal was put under public consultation by the two Regulators together with the IGB Network Code in Q3 of 2019 and is currently under completion.

The construction of the pipeline is currently expected to start in Q4 2019, imposing a delay of its Commercial Operation Date, which is now estimated in January 2021 and not later than July 2021.

The TAP pipeline

The construction of the TAP is at a very advanced stage. TAP AG reports a completion rate of 84.1% of the total length of the pipeline at the end of 2018. This rate is much higher in the Greek territory as many projects are being completed while a significant portion of the land has already been restored. The pipeline is expected to operate commercially in 2020. The regulation of access to the TAP pipeline was set out in the "Final Joint Opinion of the Energy Regulators on TAP A.G.'s Exemption Application: Autorita per l'energia elettrica e il gas (Italy), Enti Rregullator i Energjise (Albania), Ρυθμιστική Αρχή Ενέργειας (Greece)» (FJO). This FJO is a result of collaboration of the regulatory authorities of Italy, Albania and Greece, following decision C(2013)2949_final/16.05.2013 of the European Commission and it constitutes the Exemption Decision under Article 36 of Directive 2009/73/EC and it was approved by RAE's Decision No. 269/2013. The conditions laid down for TAP operation, as a result of the cooperation between the three national Regulatory Authorities as well as the European Commission and the Energy Community, safeguard competition in the European Single Market in the best possible way.

During 2018, TAP AG continued to meet its obligations under both the FJO and the national and EU law that govern the project. In this context, RAE, in cooperation with the Regulatory Authorities of Italy and Albania, ARERA and ERE respectively, has worked on the following issues:

1. TAP network code

The code must be submitted at least 12 months prior to the commercial operation of the pipeline, which is set within 2020, to the Regulatory Authorities for approval. The network code is the main regulatory framework that will define the rules of third-party access to the pipeline for the capacity that is not exempted under the FJO.

In this context, TAP AG has already begun, since 2015, the procedures for the formulation of the regulatory text of the TAP Network code and to this end there is constant communication between the company and the national regulatory authorities of energy of Italy, Greece and Albania.

During 2018, three meeting between the representatives of TAP AG and the three Regulatory Authorities were held to resolve any network code specific issue. The draft Code was submitted by the company for public consultation from August 7 to September 18, 2018. RAE posted a notice on its website to inform interested parties about their participation in the consultation. The final TAP proposal, together with the comments made during the public consultation, were submitted to the Energy Regulators for approval in December 2018.

2. Amendment of the TAP Tariff Code

RAE Decision 708/2018 (Government Gazette B'3661 / 2018), and corresponding decisions of ARERA and ERE, approved the amendment of the TAP Tariff Code in 2013 under the authority of the FJO. TAP AG recognized the need for a limited amount of modification to the code and submitted a proposal to the Regulatory Authorities in June 2018. Specifically, the proposed amendments to the code are summarized as follows:

a. Adjusting the formula for the Required Revenue in order for it to take into account the leap year, in order for the revenue during the leap year to be a little higher so as the unit tariff to remain stable between leap years and normal years.

b. The consumer price index which is used for the annual adjustment of the Revenue to be replaced by the one adopted by the European Commission with Regulation (EU) 2016/792.

c. The redistribution of the excess Revenue to the Users to be on an annual basis rather than on a semi-annual basis

These changes were judged reasonable by the three Regulatory Authorities and o the benefit of the Users. However, as part of the TAP Tariff Code is included in the specific terms of the Gas Transportation Agreements concluded with pipeline users, following a Decision of RAE and a recommendation to the Regulatory Authorities of Italy and Albania, the Authorities requested TAP AG to contact its users in order obtain their consent for the proposed amendments.

3. New Market Test Approval

In accordance with paragraph 4.1.7 of the Exemption Decision (FJO), TAP is required to conduct Market Tests to allocate any remaining pipeline capacity at least every 2 (two) years starting from the date of its commercial operation, with the approval of the relevant Guidelines set by the Energy Regulators. These Market Tests concern the expansion capacity, ie increasing the technical capacity of the pipeline from the initial capacity of 10bcm / year to 20bcm / year by installing the necessary compressors along the pipeline. The expansion of the capacity will be conducted only if it is considered economically feasible.

The extra capacity has not been granted an exemption from third party access and will therefore operate in a fully regulated regime. In this light, the European Capacity Allocation Regulation (EU) 459/2017 (NC CAM) , which provides for a specific procedure for increasing the capacity of a regulated pipeline, should apply to the allocation of new capacity.

Following extensive discussions with the Regulatory Authorities, which took place during 2018, in autumn of the same year, TAP AG submitted a proposal for approval on how to conduct the Market Test as compatible as possible with the FJO and the NC CAM Regulation, in collaboration with the adjacent TSOs, DESFA and SNAM Rete Gas.

The processing of the proposal is expected to be completed by April 2019, with TAP conducting the first phase of the Market Test in July 2019, in application of the NC CAM Auction Calendar.

4. Obligations arising from the ITO Model

TAP AG has been certified by the Regulatory Authorities under the ITO model as it is defined in Directive 2009/73/EC (RAE Decision 45/2016, Government Gazette B '972 / 8.4.2016). Regulators have been monitoring the implementation of the company's obligations under the ITO model. During 2018, there were extensive discussions on the appointment of a Supervisory Board. Regulators made extensive comments and the final TAP proposal is expected.

5. Independent Natural Gas System License and Independent Natural Gas Operation System License

Regarding the segment of the pipeline located in Greek territory, the Natural Gas Licensing Regulation provides for the issuance of an Independent Natural Gas System license and an Independent Natural Gas Operation System License. TAP received its Independent Natural Gas System license in 2014 (Decision 431 / 30.7.2014). In December 2018, this License was requested to be amended, due to changes in the TAP AG shareholder composition, as well as a redefinition of the timetable for the commercial operation of the pipeline, which is now set for 2020. The decision on the amendment is expected within the first quarter of 2019. In December 2018, TAP AG also filed an application for an Independent Natural Gas Operation License.

The FSRU in Alexandroupolis (Gastrade)

In June 2018, Gastrade submitted to RAE a request for the exemption of the planned FSRU from certain provisions of the Gas Directive, and subsequently also an amendment of its INGS license. Following the exemption request, the first phase of the market test took place between 30 October 2018 and 31 December 2018 following the approval by RAE of both the Guidelines (Decision 911/2018) and the Notice (Decision 1027/2018) addressed to interested parties. The second and binding phase of the market test, upon the results of which RAE will adopt its decision concerning the exemption request, will take place in 2019.

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 Trading Point of the National Natural Gas System or at a physical delivery point.

To boost competition and liquidity in the Greek gas market, the Competition Commission, in November 2012, following a referral from RAE, has adopted a gas release mechanism as a commitment in an alleged abuse of dominance case against DEPA SA. Suppliers and eligible customers entitled to participate in the auctions based on DEPA's corresponding commitment to the Competition Commission. 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 wherein all major gas market players participated[13].

Amongst the innovations incorporated therein RAE was attributed the duty to validate the reserve price of the auctions. In this regard, in 2018, based on the methodology for setting the auction reserve price, by Decision 1130/21.11.2018 RAE approved DEPA's overhead cost at 0.0061 €/MWh for the annual auction (which for 4,210 TWh equals to 25.600 €) and at 0.022 €/MWh for each of the quarterly auctions (which for 2,806 TWh each equals to a total of 62.400 €) of 2019.

Also, natural gas quantities purchased in DEPA's auctions are delivered only to the Virtual Trading Point (VTP) and DEPA, since 2016, has been obliged by law to a gradual increase in total quantities available as a percentage of sales of the previous year as follows: 16% in 2017, 17% in 2018, 18% in 2019 and 20% in 2020. Additionally, the auction process has been modified as each action will now take place in two phases. In the first phase both suppliers and eligible customers have the right to participate, while in the second phase of each auction, where more than 10% of the gas is auctioned, only gas suppliers are eligible to participate.

Moreover, in July 2018, the Balancing Platform was launched, in line with provision of the 4th amendment of the Natural Gas Network Code and the "Balancing Manual". The TSO, using market mechanisms, through daily or intraday auctions, purchases and sells the quantities of natural gas required to cover the imbalances of the natural gas system.

The auctioned natural gas amount by the TSO (natural gas buying and selling balancing auctions) for the period between July and December 2018 corresponded to 247,760 MWh which is the 0.87% if the total quantities injected into the NNGTS. Nine Users have participated in the auctions so far but their number is increasing.

---

[13] Thus, to offer Suppliers and Customers the ability to put together a flexible portfolio for the supply of natural gas and in addition to the current system of quarterly auctions, DEPA has undertaken to make natural gas available on an annual basis in the electronic auctions, i.e. with an absorption period of one calendar year (annual auctions). Additionally, to further reduce dependence of DEPA Customers by DEPA and to equally treat all participants in the auctions, irrespective of the supply contract that they have concluded with DEPA (with or without transmission services), DEPA undertook (as of 01.01.2015) to make all quantities available through the annual and quarterly auctions solely at the Virtual Nomination Point (VNP) of the National Natural Gas System (NNGS).

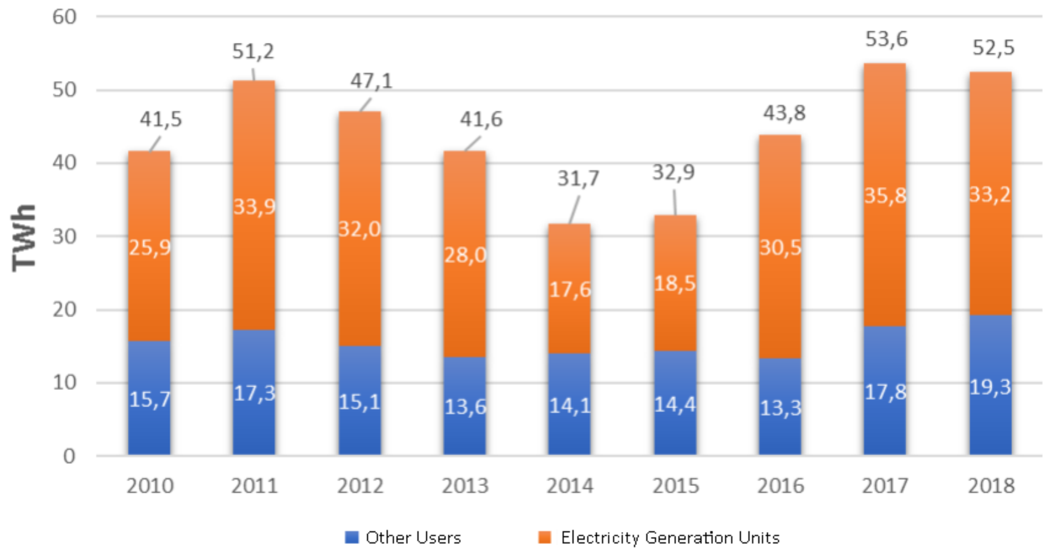


Figure 25: Natural Gas Consumption in Greece

RAE, within the framework of its competences regarding monitoring of the Greek energy market, published 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 26 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 2018 through December 2018.

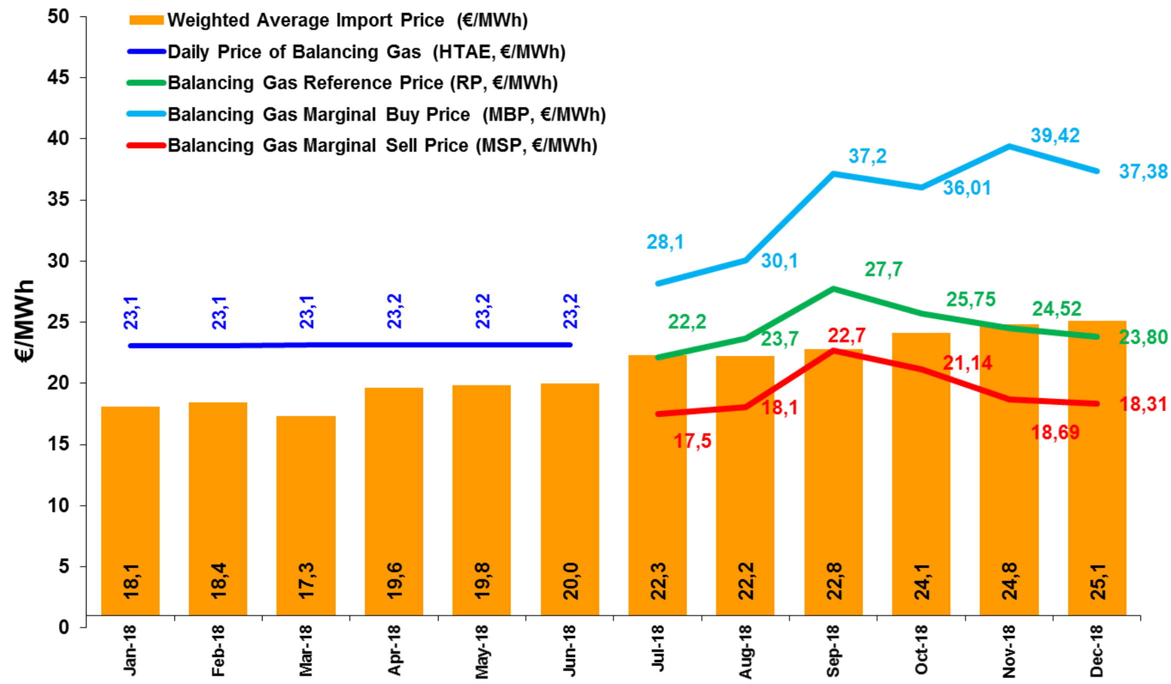


Figure 26: Price Monitoring in the Wholesale Market

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

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. This was clearly intensified after the beginning of the operation of the Virtual Trading Point 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 balancing platform also provides a "signal" for the price of natural gas in the Greek market, helping considerably in the creation of an organized gas market in the country in the near future.

4.2.2. 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 2018. 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 confirmed in 2018, the Revithoussa LNG terminal remains the main channel/opportunity for new entrants in the Greek gas market. This remains true regardless of the fact that, as already explained above, in 2018 more companies imported natural gas from the IP Kulata – Sidirokastro.

After the full liberalization of the natural gas market in early 2018 (opening up of the retail market), the publication of the weighted average import price, in combination with the balancing gas reference prices, as well as the balancing gas marginal buying and selling prices, but also the DEPA auctions prices, provide useful information on the price conditions in the Greek natural gas market which enables interested parties to pursue further business opportunities and the development of competition for the benefit of gas consumers.

4.2.3. Description of the Gas retail market

Radical reclassifications in the retail market of natural gas brought in 2018, with the complete liberalisation of the gas market. In more detail, from 01.01.2018 (law 4336/2015), the monopoly of the gas supply companies in Attica and Thessaloniki/Thessaly was abolished, and now the gas supply companies can operate on the market, supplying individual gas packages or combined electricity and gas packages, without geographical restriction, provided that there is an active network in the case of gas. At the same time, with the establishment of the gas distribution companies, the separation of the distribution activity from that of the supply of gas was implemented.

At the end of 2018, a total of 21 suppliers were active in the retail market of natural gas:

	Supplier name:
1.	ANOXAL
2.	BA GLASS
3.	CORAL
4.	DEPA
5.	ELVALCHALCOR
6.	ELPEDISON
7.	MYTILINEOS
8.	ZENITH
9.	EFA ENERGY

10.	FULGOR
11.	NATURAL GAS ATTICA
12.	GREENSTEEL
13.	HERON
14.	M & M
15.	MOTOR OIL
16.	NRG
17.	PROMETHEUS
18.	SIDENOR
19.	SOVEL
20.	VOLTERRA
21.	WATT & VOLT

Table 42: Suppliers active in the retail market of natural gas (2018)

The Herfindahl-Hirschman Index (HHI) at the end of the year is estimated at 3,511, as estimated by consumption volume. Like the electricity market, the gas market is considered to be strongly concentrated (although to a lower extent than electricity), as it exceeds the threshold of 2,000 (high market concentration limit).

The total volume of gas consumption in the year 2018 did not show any particular variations compared to 2017. Table 43 shows the evolution of consumption within the distribution networks of Attica, Thessaloniki, Thessaly and the rest of Greece for the period 2011-2018. It appears that the consumption of natural gas was at 10.25 TWh (compared with 10.42 TWh of the year 2017), i.e. it showed a small reduction of 1.6%.

Distribution networks	**Consumption (TWh)**							
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Attica	3,71	3,33	2,79	2,72	3,11	2,87	3,53	3,49
Thessaloniki	2,39	2,33	2,01	2,04	2,38	2,34	2,82	2,73
Thessalia	1,41	1,28	1,05	1,1	1,1	1,14	1,6	1,61
Rest areas of the country	2,35	2,4	2,21	2,48	2,47	2,61	2,47	2,42
Total	9,86	9,34	8,06	8,34	9,06	8,95	10,42	10,25

Table 43: Evolution of consumption within the distribution networks of Attica, Thessaloniki, Thessaly and rest of Greece for the period 2011-2018

Regarding supplier switching, with the entrance of 21 gas supply companies in the retail market, the first switching trend between suppliers appeared. Table 44 shows the number of customers who changed supplier in 2018, as well as their corresponding consumption. As it turns out, the highest switching rate was that of industrial customers (8.8% by number of customers and 9.1% by volume of consumption), followed by commercial and domestic customers (1.0 to 3.0%).

Customer Category	**Total number of active customers, 2018**	**Number of customers switching Supplier in 2018**	**Percentage of switching (Number of customers) (%)**	**Customers' total consumption in 2018 (MWh)**	**Customers' consumption switching Supplier, 2018 (MWh)**	**Percentage of switching (in volume) (%)**
Household	425.025	7.197	1,69%	4.539.913	51.126	1,13%
Commercial	15.986	386	2,41%	1.575.942	46.665	2,96%
Industrial	319	28	8,78%	4.133.237	374.757	9,07%
Total number	**441.330**	**7.611**	**1,72%**	**10.249.092**	**472.549**	**4,61%**

Table 44: Customers switching their natural gas supplier per consumer category, 2018 (Source: Natural gas Operators' data)

The companies "Zenith SA" and "Attiki Natural Gas Distribution Company SA" were the prevailing natural gas suppliers in the retail gas market (residential, commercial and industrial consumers), representing 71.01% and 26.40%[14], respectively, of the total number of connections at the end of 2018 and the 46.81% and 35.75% of the total natural gas volume consumed.

During 2018, the total gas consumption in the Distribution Networks was 10.25 TWh, showing a decrease compared to 2017 of -1.6%. A decrease 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 2018 amounted to 2.42 TWh versus 2.47 TWh in 2017, a decrease of about two percent (- 2.06%). A small percentage increase was recorded in Distribution Network of Thessaly, where consumption in 2018 amounted to 1.61 TWh, compared with 1.60 TWh in 2017, i.e. an increase of less than 1 percent (0.62%). Respectively, consumption in Thessaloniki's Distribution Network decreased by about three percent (- .29%) (2.73 TWh in 2018 compared to 2.82 TWh in 2017), the Attica Distribution Network at one percent (--1.14%) (3.49 TWh in 2018 versus 3.53 TWh in 2017).

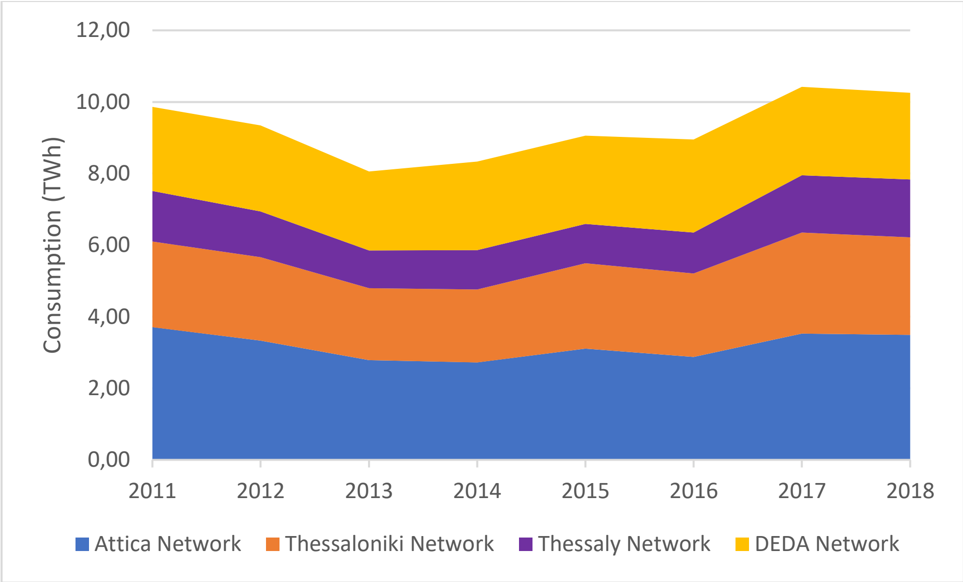


Figure 27: Total Natural Gas Consumption and per distribution network (2011-2018)

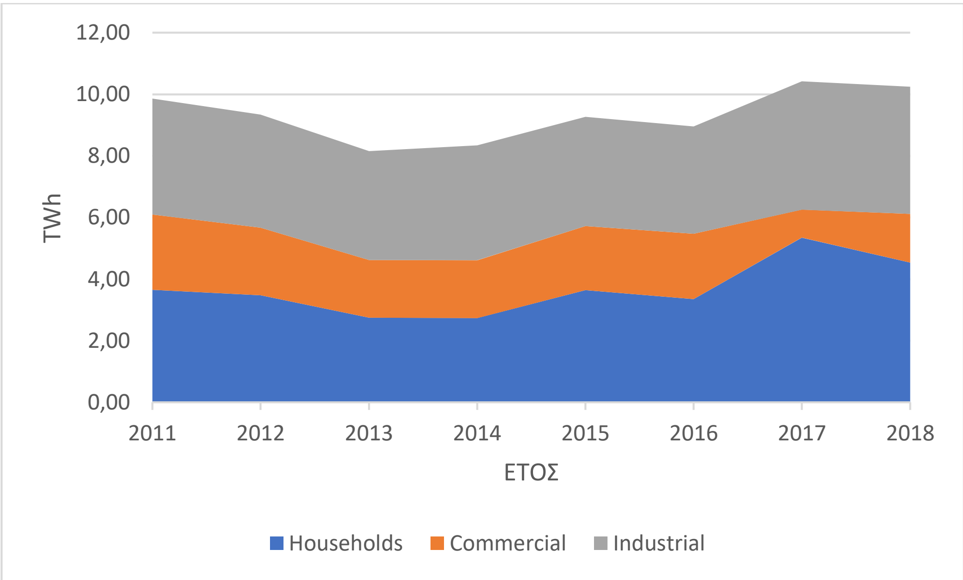


Figure 28: Natural Gas Consumption per customers' category (2011-2018)

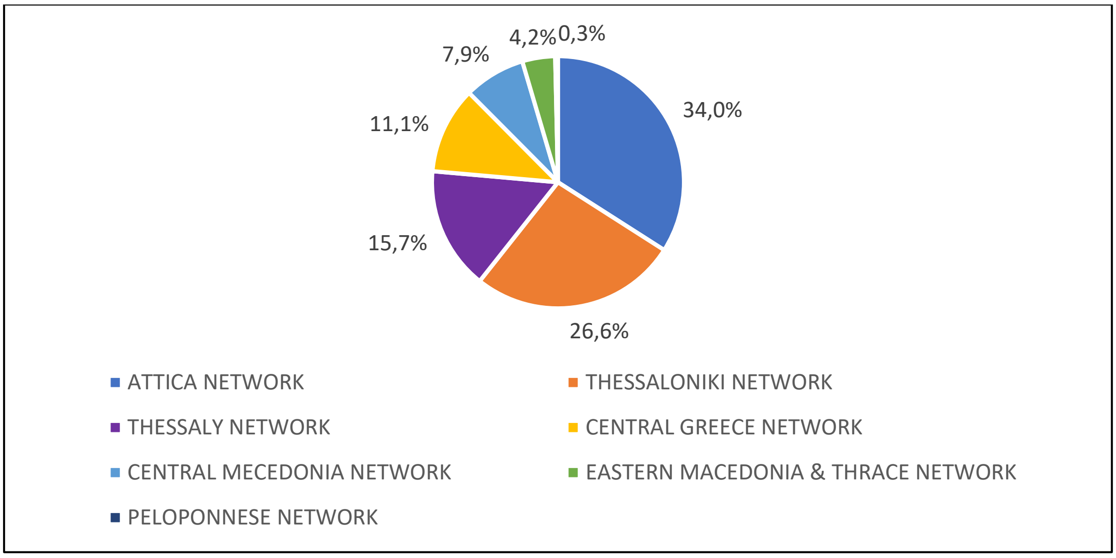


Figure 29: Natural Gas Consumption percentage per Distribution Network (2018)

The figure above shows the percentage of natural gas consumption per Distribution Network for the year 2018, with the Attica Distribution Network holding the highest percentage of Gas Distribution with 34% then follows the Distribution Network of Thessaloniki with 26.6%, the Thessaly Network with 15.7%, the Network of Central Greece with 11.1%, the Network of Central Macedonia with 7.9%, the Network of Easter Macedonia & Thrace with 4.2% and the Peloponnese Network with 0.3% which is the lowest percentage of natural gas distribution network in Greece.

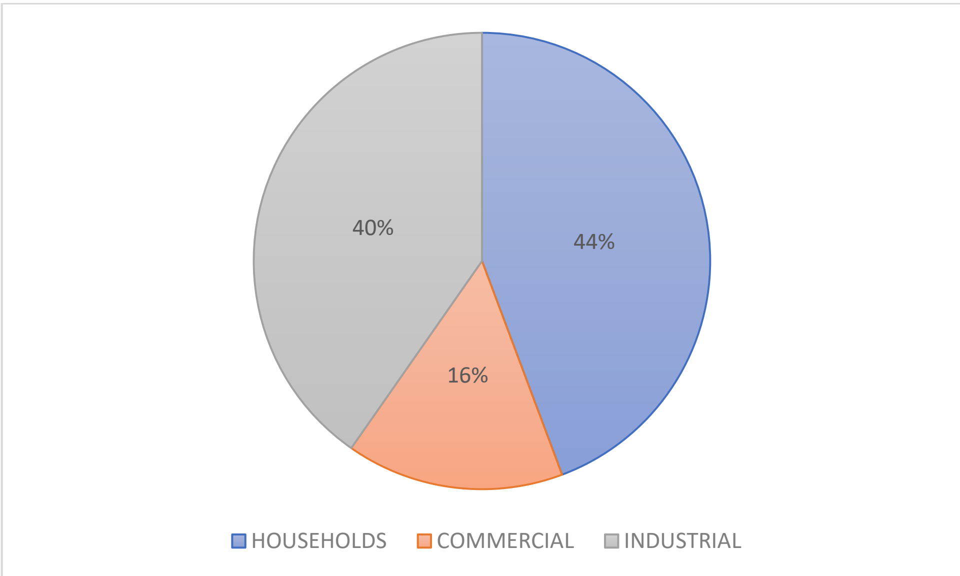


Figure 30: Natural Gas Consumption percentage per consumer category (2018)

As shown by the data presented above, households' share reaches forty-four per cent (44%), industrial users amounts to forty per cent (40%) and commercial users is up to sixteen per cent (16%) in the gas Distribution Networks in the country. More specifically, in 2018 household consumption decreased grew by fifteen per cent (-15%), from 5.34 TWh to 4.54 TWh, and the industrial sector by one per cent

(-1%) from 4.16 TWh to 4.13 TWh. The commercial sector experienced an increase in consumption by seventy three percent (73%), from 0.91 TWh to 1.58 TWh.

In 2018 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.

Table 45: Distribution tariffs per Distribution Network, 2018

Capacity Charge (€/MWh/h)							
	Attica	Thessaloniki	Thessaly	Central Greece	Corinth	Central Macedonia	Eastern Macedonia and Thrace
Residential	1,122.31	450.06	521.74	1,229.37		791.16	546.44
Commercial	1,122.31	450.06	521.74	1,240.70		828.81	597.20
Industrial	4,521.80	1,800.46	2,087.24	7,279.12	5,789.12	4,561.53	4,865.53
Cogeneration/ air conditioning	1,121.67						
Energy Charge (€/MWh)							
	Attica	Thessaloniki	Thessaly	Central Greece	Corinth	Central Macedonia	Eastern Macedonia and Thrace
Residential	14.40	11.87	12.94	13.44		11.57	11.84
Commercial	14.40	11.87	12.94	11.34		7.53	7.34
Industrial	0.69	0.29	0.35	0.56	1.18	0.42	0.49
Cogeneration/ air conditioning	3.78						

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.

	2012	2013	2014	2015	2016	2017	2018
Attica Distribution Network	78,000	81,000	86,000	94,000	98,000	106,000	120,000
Thessaloniki Distribution Network	155,000	164,000	172,000	196,000	210,000	222,000	227,000
Thessaly Distribution Network	55,000	62,000	67,000	78,000	85,000	92,000	94,000

Table 46: Total Number of active consumers per Distribution Network, 2012-2018

Natural Gas Distribution Company	Category	Number of contracts	Number of orders executed	Average implementation time (business days)
EDA Attica S.A.	Households	13.851	15.070	40,2
	Commercial	511	434	42,8
	Industrial	5	2	199,5
EDA Thessaloniki – Thessaly S.A	Households	46.656	24.887	33,5
	Commercial	1.089	507	34,0
	Industrial	10	5	31,0
DEDA S. A.	Households	143	143	30,8
	Commercial	4	4	32,0
	Industrial	5	4	151,0
Source: Natural Gas Distribution Companies				

Table 47: Statistical data of new natural gas connections (2018)

4.3.2. Definition of Vulnerable Customers

In June 2018, a new Natural Gas Supply Code was adopted (Government Gazette 1969/1.6.2018) in compliance with article 52 of Law 4001/2011 on the definition of Vulnerable Customers. Specifically, on the basis of Law 4001/2011 the following categories of Customers are defined as Vulnerable Customers:

(a) Economically weak households affected by energy poverty.

(b) Customers, or persons who are lawfully under their care, who are heavily dependent on continuous and uninterrupted power supply. This category includes customers who require mechanical support and in particular, those who require continuous supply for the operation of vital support or monitoring devices, including respiratory or cardiac support devices and any similar physical device.

(c) Elderly customers who have reached the age of 70, provided that they do not stay with another person who has not reached the age limit.

(d) Clients with serious health problems, in particular people with severe physical or mental disabilities, as well as movement, hearing and visual problems which result in their disability to negotiate their contractual relationship with the supplier.

(e) Customers in remote areas, especially in the Non-Interconnected Islands who are entitled to the same services both in terms of price, quality, security of supply and transparency of contractual terms and other conditions as the other customers.

Depending on the difficulties encountered by each category, additional measures may be taken for their protection, in particular the provision of reduced bills or discounts, the installation of metering tools with the option of prepayment, or other favorable payment terms, alternative means of access to payment services and customer services as well as the prohibition of disconnection from the network of vulnerable consumers at critical times.

The criteria, the conditions and the procedure to include a customer in the category of vulnerable customers are determined by decisions of the Minister of Environment, Energy and Climate Change. Measures related to pricing and to invoice discounts, the protection measures for each category of vulnerable consumers, both in pre-contractual level and contractual level as well as contract termination with the Supplier are determined by the relevant provisions in the Supply Code.

The new Natural Gas Supply Code lays down more provisions for vulnerable customers. Specifically, vulnerable customers are granted 30 extra days to comply with the provisions set out in their Supply Contract before the Supplier can terminate their contract. Furthermore, the deadline to pay their bills cannot be less than 40 days. The Supplier is also obligated to provide the opportunity to his vulnerable customers to pay their debts in installments without interest. Each installment may not be higher than the 50% of the monthly cost for the natural gas consumed by the vulnerable customer. However, the above option does not relieve the vulnerable customer of his responsibility for timely payments of his debts to the Supplier. For vulnerable customers who are heavily dependent on continuous power supply due to constant need for mechanical support as well as for those who have severe health issues, the Supplier may terminate the contract only in the occurrence that the customer hasn't paid six consecutive bills and has received notice of the ability to settle his debts.

Under the new code, the Supplier gives top priority to vulnerable customers. He is obliged to take all appropriate measures to inform and serve these customers. Especially in the case of disabled customers, the Supplier is required to have well-trained staff available and to maintain special accessibility specifications on his website. Physical customer service points must comply with the accessibility specifications for people with disabilities, in accordance with the applicable legislation. Additionally, the Supplier operates a dedicated hotline to serve Vulnerable customers. Calls coming from these customers are always charged as city calls and all telephone conversations are recorded after prior customer notification. The Supplier shall also provide customers with severe visual impairment the ability to choose between: Large font size accounts, voice accounts, telephone communication, written information in Braille, prior notice about planned power outages and special badges for the representatives of the Suppler so they can easily be recognized by people with disabilities. The Supplier also provides the customers with severe hearing problems, the ability to visit their home in case of emergency (power outrage etc.). The ability to be serviced by a person who knows body language or by using special devices that allow communication with deaf customers as well as sending special information via SMS and email. Specifically, for customers with mobility problems, the Supplier is obliged to provide alternative means of handling their transactions that do not require the physical presence of the Client.

4.4. Other regulatory developments

4.4.1. The regulatory framework for Remote Distribution Networks

The conditions for the development of Remote Distribution Networks and the conditions of access to a Compressed Natural Gas (CNG) or Liquefied Natural Gas (LNG), as well as any other specific issue and implementation detail were discussed on the public consultation set up by RAE on 07.05.2018, with 5 stakeholders participating therein.

The Regulatory Framework was set out in RAE's Decision No 643/2018 on the "Framework for the development of Remote Distribution Networks using Compressed Natural Gas / Liquefied Natural Gas". Specifically, the DSO of the gas network may construct Remote Distribution Networks within the area that is under its license. During the submission of the Natural Gas Distribution Network Development Program for approval, the competent Operator may recommend the construction of a Remote Distribution Network. This proposal must be accompanied by a cost-benefit study that includes the projected consumption (the number of connections per category of consumers and the volume of the natural gas), the projected construction cost of the Remote Distribution Network, the projected cost of the connection of the Remote Distribution Network to the existing Transmission or Distribution Network through a pipeline (if its technically feasible) and the evaluation results of the criterion of the Article 12 of the Pricing Regulation, and in particular the impact on the Average Distribution Charge. Provided that all distribution users have equal terms in their access to the Remote Distribution Network, it may be supplied either directly by them or by the Network Operator (Virtual Network).

As far as the access to the Remote Distribution Network through the Virtual CNG pipeline, the Compressed Natural Gas decompression station, after which the gas is fed to more than one final customer, is not a Distribution Network Entry Point but a continuation of the Distribution Network. The Operator has in his possession but doesn't own the natural gas during the entire process of compression, CNG transportation and decompression of the gas. The Operator shall, also, ensure that the natural gas imported into the Remote Distribution Network has the same properties with the existing gas in the distribution network. The Operator shall receive Compression and Transmission Services of Compressed Natural Gas following competitive tenders with natural or legal persons, based on transparent economic, objective, non-discriminatory and technical criteria.

The total cost of the Virtual Network service per Remote Distribution Network is determined by the quantities of the Natural Gas measured by the meter which is installed after the decompressor, after which, it is injected into the Remote Distribution Network. The Operator monitors any losses that occur during the compression, transmission and decompression process and informs RAE the results. RAE, in the context of the approval of the Development Program, evaluates the Operator's recommendation and decides on the Development of the Remote Distribution Network as well as the way the Remote Network is powered. In addition, in the case of the approval of supply through the virtual pipeline, RAE approves the maximum price per kWh, incrementally depending on the distance covered by the virtual CNG/LNG pipeline for the next year, it also approves the terms and conditions of the tender carried out by the Operator.

The methodology for setting the maximum price is cost oriented. The previous year's maximum price is valid up until RAE determines the maximum price for the Virtual Pipeline service for the following year. RAE may impose additional conditions on the Operator for the construction and supply of a Remote Distribution Network (e.g. installation of a second compressor, construction of an alternative Entry-Point). In case of approval of the construction of a Remote Distribution Network through Virtual Pipeline, the Operator shall immediately conduct a tender for each Remote Distribution Network separately and informs RAE of its results.

4.4.2. Methodology for setting typical consumption curves

Pursuant to par. 1 of art. 21 of the Distribution Code, after a long preparation and consultation with the relevant stakeholders and in particular with the DSOs, RAE approved a common methodology for the non-metered customers by Decision 125/2018.

4.4.3. Metering Regulation for the Distribution Networks

After several revisions of the initial draft originally submitted in 2016, RAE put in public consultation the latest draft on 7 July 2018, to which there were three participants. RAE will adopt one Metering Regulation for all distribution networks in 2019.

4.5. Security of Supply

RAE is appointed a Competent Authority for the safeguarding of fulfillment measures which are defined in the new European Regulation on the security of gas supply (2017/1938) of European Parliament and Council of 25th October 2017.

Implementation of Regulation (EU) 2017/1938

Regulation (EU) 2017/1938 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010 has introduced significant changes regarding the obligations of Competent Authorities and has enacted provisions for Regional Cooperation. Based on these provisions, RAE, as being the Competent Authority, is participating in the development of three (3) Common Risk Assessments (CRAs) of all relevant risk factors which could lead to the materialization of the major transnational risk to the security of gas supply to the Ukrainian, the Algerian and the Trans-Balkan risk groups, as listed in Annex I of the Regulation. Moreover, RAE has been designated as the coordinator for the Trans-Balkan Risk Assessment, which is currently under development in collaboration with DESFA, IPTO, JRC and the other competent authorities of the Member States of the risk group (i.e. Bulgaria and Romania). The CRA for the Algerian risk group has been completed in the end of 2018, while the CRA of the Ukrainian risk group is expected to be completed in the first quarter of 2019.

In addition, RAE, applying the relevant provisions of Regulation (EU) 2017/1938, initiated in 2018 the process of preparing an updated National Risk Assessment (NRA) of all relevant risks that may affect the security of gas supply – as defined in Article 7 of the Regulation. The NRA, according to the provisions of the Regulation, will include among others,

a) a detailed regional and national gas system description,
b) the calculation of the N – 1 formula at national and regional level for the years 2019-2021 and
c) investigation of various scenarios of exceptionally high gas demand and disruption of gas supply, considering the history, probability, season, frequency and duration of their occurrence and assessment of their likely consequences. The simulation of the scenarios is carried out taking into account the latest gas demand estimates for the years 2019-2020, 2020-2021 and 2021-2022, the completion of the second phase of the upgrade of Revithoussa LNG terminal and the entry into commercial operation of the Natural Gas Pipeline (TAP) by the year 2020.

Preventive Action Plan

During 2018, RAE's activities regarding security of supply (SoS) were mainly focused on the development of the Preventive Action Plan (PAP), which was prepared in accordance with the provisions of Articles 8 and 9 of Regulation (EU) 2017/1938 and in collaboration with DESFA, IPTO, the Ministry of Environment and Energy and the JRC of the European Commission. The Plan aims to present appropriate measures (actions) to reduce or eliminate the risks that may affect the security of supply of the country with natural gas.

The National Risk Assessment for the years 2017-2020, which was completed in September 2017, was the basis for drawing up the Plan. This study examined in detail the risks that could affect the security of gas supply and analyzed twenty (20) scenarios of potential disturbances in the supply and/or demand for natural gas. During the simulation, the deficiencies incurred in the mass balance were estimated, the impact on Electricity Generation, Industrial and Protected Customers was assessed, and the level of risk of each scenario was evaluated.

In the context of PAP, the development of new actions was examined along with the improvement of existing measures related to:

• demand-side management;

• emergency supply and temporary storage of LNG;

• increase of the level of the power sector preparedness to overcome risks/disruptions in the supply of natural gas

The methodology used to identify and evaluate the actions was based (a) on the provisions of Regulation (EU) 2017/1938 and (b) on the JRC report on Good Practices for the Development of Preventive Action Plans and Emergency Plans[15]. The main steps followed were the following:

1. Identification of the crisis scenarios that should be addressed based on the National Risk Assessment and prioritization;

2. Initial identification of actions deemed feasible and suitable to support the objectives of the Plan;

3. Re-simulation of scenarios and assessment of effectiveness of actions to reduce risk and comply with the Infrastructure and Supply Standards;

4. Assessment of the cost of the actions and their possible impact on the environment, the functioning of the market and on the security of gas supply of other Member States;

5. Development and implementation of Multi-criteria Decision Analysis for evaluating the actions;

6. Risk reduction loop and residual risk assessment.

In addition to the above, the Plan examined the ability to comply with the Infrastructure Standard (N-1) before and after the implementation of the planned actions, as well as a set of support measures and obligations that enhance the prevention and safe operation of the system.

[15] JRC, Preventive Action Plan and Emergency Plan Good Practices, 2012

Finally, the Plan presented all the infrastructure projects that are important for the country's security of supply, which are included in the third (3rd) Common Interest List (PCI List), as well as ongoing projects that have been included in the 10-year Development Plan of the NNGS.

After the approval[16] of the Plan with Decision No 500/2018 (Government Gazette B' 2672/06.07.2018 and 3329/10.08.2018), RAE issued three (3) Decisions for the implementation and the financing (through the Security of Supply Levy) of the actions and measures included in the PAP, i.e.:

a) Decision No 1287/2018 (Government Gazette B΄ 5900/31.12.2018) on "*Regulating the Management of the National Gas System for the Implementation of Action D5 of the Preventive Action Plan to Ensure Security of Natural Gas Supply*".
b) Decision No 1211/2018 (Government Gazette B΄ 5891/31.12.2018), which is an amendment of RAE's Decision 344/2014 on "*Determining the Maximum Allowed Limit of Security of Supply Account, Security of Supply Levy per Category of Gas Customer, and Standard Power Unit, in accordance with the provisions of article 73 of Law 4001/2011, as applicable*".
c) Decision No 1299/2018 (Government Gazette B΄ 164/30.01.2019) "*Amendment to the provisions of the System Operation Code* (Government Gazette B΄ 103/31.01.2012) *of the Greek Electricity Transmission System and the Electricity Transactions Code* (Government Gazette B΄ 12310/2018) *for the implementation of Action D6 of the Preventive Action Plan*".

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 has been closely monitoring the 2nd upgrade of the LNG terminal station at Revithoussa island, a project of great importance for the country for the security of gas supply. In this context, RAE issued Decisions No 257/2018, No 1088A/2018 and No 427/2018 which approved the regulatory framework that was deemed necessary for the support of the upgrade of the terminal.

4.5.1. 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 2019-2028 NNGS Development Study.

[16] RAE, in accordance with article 12 of Law 4001/2011 and paragraphs 1 and 2 of article 73 of Law 4001/2011, held a public consultation from 6/2/2018 to 26/2/2018 on draft PAP as well as with the neighboring countries, Bulgaria and Romania.

4.5.1.1. Current demand

The demand for Natural Gas in 2018 recorded 4.8bcm, out of which approximately sixty three percent (63%) came from the power generation sector, as shown in Table 48.

	bcm@15⁰C	Mtoe (HHV)
Power Generation	3,04	2.77
Industry & HP customers	0.82	0.75
Distribution Networks	0.94	0.86
TOTAL	4.8	4.38

Table 48: Natural Gas Demand per sector in 2018

As depicted in Table 48, total gas demand in 2018 (4.8 bcm) was maintained at the same level as in 2017 (slight decrease of 2%).

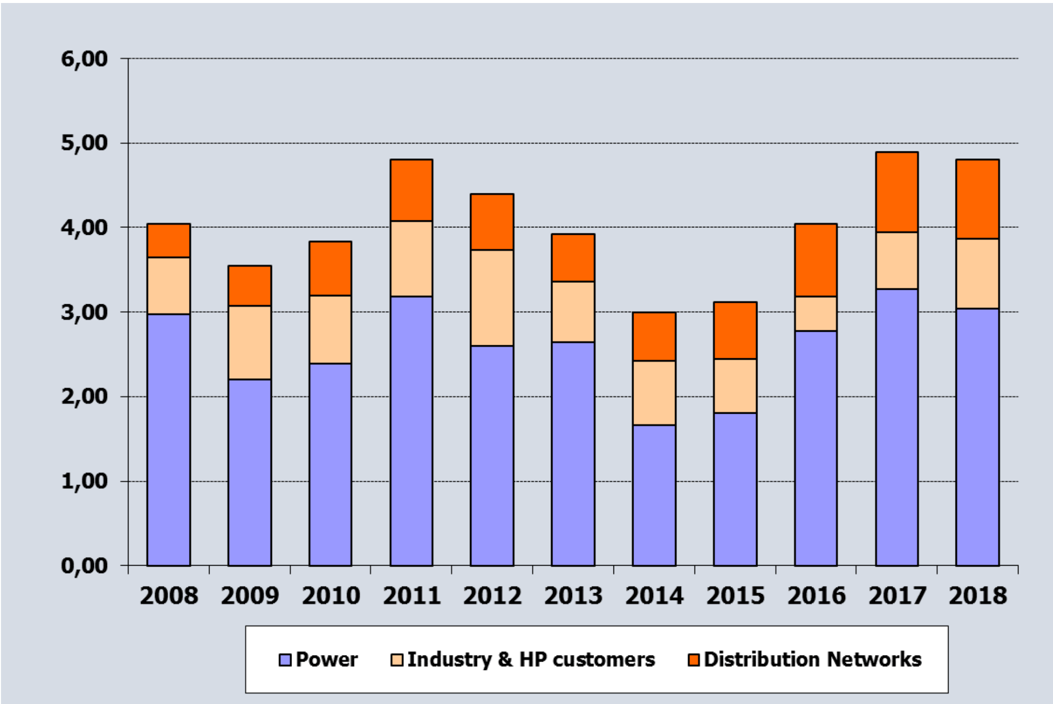


Figure 31: Evolution of natural gas consumption per sector *(2008-2018)*

There is no indigenous gas production in Greece. Figure 32 provides the share of imports of natural gas from each source during the last 11 years (2008-2018). In 2018, natural gas was imported in the National Natural Gas System through three (3) entry points. Approximately sixty five percent (65%) of the gas imported into the country came from Russia, fourteen percent (14%) was imported from Turkey and the remaining approximately twenty one percent (21%) was imported as LNG at the island of Revithoussa and was injected into the transmission system from the Agia Triada entry point.

Regarding the imports of LNG, as shown in Figure 33, 82% of the LNG was imported by Algeria, 8 % from Qatar and 10% from USA.

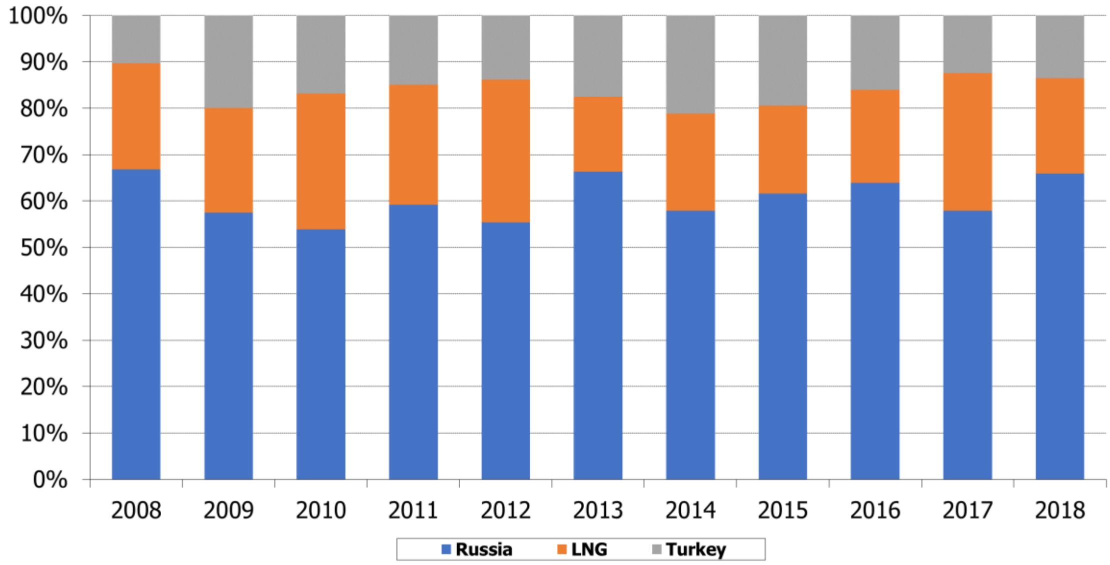


Figure 32: Share of natural gas supply sources from 2008- 2018

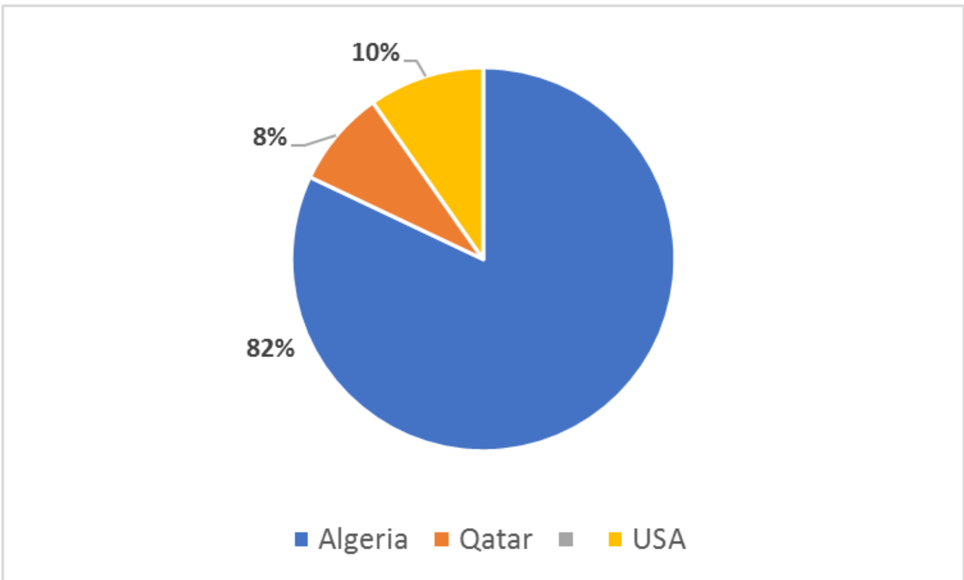


Figure 33: Share of LNG supply sources per country in 2018

4.5.1.2. Projected demand

DESFA's projections (NNGS Development Study for the period 2019-2028) of natural gas demand for the next three years (2019 to 2021) are summarized in the table below.

	2019	2020	2021
Power generation	2,69	2.85	2.58
Consumers connected to High Pressure	0.71	0,71	0.69
Distribution Networks	0.99	1,02	1,04
Transit	0.11	0.53	0.11
Small scale natural gas	0	0.21	0.63
Total	4.5	5,33	5,06

Table 49: Future natural gas demand in bcm (DESFA's estimates)