ΡΥΘΜΙΣΤΙΚΗ ΑΡΧΗ ΕΝΕΡΓΕΙΑΣ
REGULATORY AUTHORITY FOR ENERGY

National Report 2022

Regulation and performance of the electricity market and the natural gas market in Greece, in 2021.

Regulatory Authority for Energy (RAE)

Athens, June 2022.

REGULATORY AUTHORITY FOR ENERGY

132, Piraeus str., 118 54 Athens, Greece

Tel.: +30 210 372 7400,

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

Board composition

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1 FOREWORD

Dear Readers,

In 2021, in view of its institutional role and its statutory competences, RAE remained firmly committed to its core values and actively pursued its mission towards the creation of a secure, competitive and sustainable energy market at national, regional and EU level.

Throughout the year, RAE was faced with numerous challenges that had arisen from the implementation of the Target Model, which was first put in operation in November 2020, the effects on the energy markets by the unprecedented COVID pandemic as well as the high energy prices that were recorded from the summer of 2021. RAE continued to monitor the timely execution of the network operators' development plans and strategic interconnections, the establishment of the new electricity market design as per the EU Target Model and the market coupling process, the successful implementation of the RES auctions, the effective monitoring of the energy markets and the empowerment of the final consumers.

Ahead of the energy transition process in the EU and worldwide, by implementing these reforms, Greece ensures its adequate participation in the integrated European energy market while safeguarding the country's security of energy supply, and securing affordable prices for households, businesses and industry that are key drivers of growth for the national economy.

In this framework, and in compliance with the responsibilities assigned by the Energy Law 4001/2011, RAE proceeded in 2021 with the adoption of a set of key regulatory decisions, opinions, and recommendations, the most significant of which are summarized hereafter and analyzed further in detail in this National Report.

The President of RAE

Assoc. Prof. Athanasios Dagoumas

2 MAIN DEVELOPMENTS IN THE ELECTRICITY AND GAS MARKETS

2.1 Electricity Sector

A. Wholesale Electricity Market

Significant progress was registered in the year 2021 regarding the operation of the three electricity spot markets (Day-ahead, Intra-day, Balancing) in Greece advancing market coupling with neighboring European markets.

Following the launch of the coupled operation of the Day-ahead Market at the Greece-Italy border in December 2020, the coupling of the Day-ahead Market of Greece with the Bulgarian market was achieved on May 12, 2021. Regarding the operation of the Intraday Market, following close cooperation between RAE and HENEX S.A. and IPTO S.A., as well as with the Regulatory Authorities and operators of Italy and Slovenia, the participation of the Greek Bidding Zone in the Complementary Regional Intra-Day Auctions (CRIDAs) was ensured as of 22 September 2021, in order to lead to a more efficient allocation of the HVDC interconnection capacity at the Greece-Italy bidding zone border, to enhance the liquidity of the Intraday Market and to provide additional tools to the participants of the Greek Electricity Market to correct their positions.

With regards to the Balancing Market and in response to a continuous increase in the costs observed in this market in the first two months of its operation RAE adopted some transitional measures to enhance the operation of the Balancing Market (Decision 54/2021), following a relevant public consultation, including the suspension of the possibility to submit Balancing Energy bids with negative prices for the period that the network in the Peloponnese System is congested.

Two key decisions to further improve the operation of the electricity markets in Greece include the following:

- Decision 703/2021 on the main principles of a methodology to distinguish balancing energy bids activated for balancing purposes from balancing energy bids activated for non-balancing purposes, i.e. for purposes related to "System constraints". Given that there was no impact assessment submitted by the TSO should the methodology proposed be implemented, RAE decided for a trial period to examine the effects of the methodology proposed and associated remuneration options.
- Decision 1014/2021 on the maximum allowable limit of validated "Physical offtake nominations", corresponding to quantities of energy traded on the forward market (either through organized markets such as the one operated by HENEX SA or through bilateral contracts), in order to give suppliers, other than the dominant supplier, a greater possibility to mitigate the effects of a strong short-term price volatility.

Also, a significant milestone was reached with the completion of the electricity interconnection of Crete to the continental Interconnected System after the completion of Phase 1 of the interconnection and the start of the operation of the Cretan market as a Small Interconnected System from 1 November

2021. RAE, after a series of intensive consultations with the relevant network operators and stakeholders, designed a hybrid model for the operation of the market of the Small Interconnected System of Crete for the transitional period from Phase I until Phase II (when the full interconnection of the island is completed). It must be noted that only 35% of Crete's load can be covered by the completion of the Phase I of the interconnection, and the direct participation of the market participants of Crete in the Interconnected System markets would result in a significant redispatching cost due to the technical congestion in the interconnection.

In 2021, RAE has also evaluated and approved the proposals of IPTO S.A. regarding the imbalances' charges applied in the Balancing Market, the Maximum and Minimum Security Level of hydroelectric power plant reservoirs, the amendment of the methodology for calculating the Balancing Energy Activated, the values of the Unit Charges of the Deviation Component and the Energy Component of the Balancing Market Charge.

RAE also adopted five implementing decisions according to the provisions of the Day-ahead Market Trading Rulebook regarding the access of Participants to specific types of Orders, the parameters for their submission, as well as the technical details regarding their content, the approval of the regulatory parameters for the calculation of the non-compliance charges imposed by HENEX for 2022 and the amendment of the methodology for the calculation of charges for the operation of the Day-ahead Market.

Finally, in order to improve the regulatory framework for the coupled operation of the wholesale electricity Market, RAE in 2021 issued a series of decisions in accordance with the provisions of European Regulations on electricity market issues (CACM, EBGL and FCA).

It is also worth noting the Authority's significant assistance to the Ministry of Energy for the preparation of the Greek Electricity Market Reform Plan, i.e. a plan for the implementation - within a specified timeframe - of actions to eliminate identified regulatory or market issues in the electricity market.

In addition to the above, RAE exercises on a continuous basis the responsibility of monitoring and supervising the energy markets and the market participants. In 2021, it laid the groundwork for the creation of automated market monitoring tools under the "Monitoring and Supervision Mechanism" promoted by RAE, to effectively monitor the competitive conditions and the behaviour of energy companies. The automated data collection by HENEX and the IPTO will be gradually enriched with automated reports and indicators/notifications.

B. Retail Electricity Market

Following the adoption Decision 409/2020 with guidelines on the transparency and verifiability of charges in the competitive part of the tariffs and RAE's Opinion 5A/2020 to the Ministry of Energy for the amendment of the Electricity Supply Code, in 2021 RAE moved along four axes to support electricity consumers in addressing the problems that have arisen due to the activation of suppliers' price adjustment clauses due to high prices recorded in the wholesale electricity markets:

A) Created an online application for submission of complaints (MyRAE), where electricity consumers can easily and quickly submit their requests or complaints to their supplier/network operator, which are automatically communicated to the responsible entity in order to be settled promptly and efficiently. RAE is automatically aware of and monitors the response of the suppliers/operators to consumers' requests and may intervene at any moment.

b) On the basis of the European Directives, it elaborated and set out for public consultation the establishment of standards for the supply contracts and the consumers' bills. The relevant standardisation, as reflected in Decision 967/2021, focuses on providing the necessary information to consumers in a clear, accurate, understandable and consumer-friendly manner.

c) It has started the systematic monitoring of Suppliers regarding their compliance with the obligations of transparency and proper information of consumers as provided for in the Electricity Supply Code in the event of a change in their contractual terms, in particular regarding the conversion of their tariffs from fixed price to a variable tariff with the introduction of a price adjustment clause. In this regard, RAE issued recommendations and invited a Supplier to a written hearing to provide explanations for its non-compliance with the above rules.

d) It strengthened its cooperation both with the Consumer Ombudsman and with consumer organisations, to inform consumers as much as possible and empower them to be able to freely exercise their right to choose a supplier.

Furthermore, RAE, noting that the unfavourable economic situation combined with the observed practice of consumers with overdue debts deliberately choosing another supplier without taking care to settle their debts before switching to the new supplier, created a cash flow squeeze and difficulty in managing their consumers' debts, reassessed the institutional framework governing the switching procedure and the mutual rights of the parties to the supply contract, in particular in the case of overdue debts, by issuing an opinion on the relevant amendment to Article 42 of the Electricity Supply Code to the Minister of Environment and Energy on the implementation of a debt flagging mechanism.

Finally, in 2021, the regulatory control and systematic monitoring of the financial transactions of retail market participants continued, with the issuance of 11 regulatory decisions to summon electricity suppliers to a written hearing, on the management of overdue regulated charges of electricity suppliers and issued 6 sanction decisions for outstanding debts that had accumulated in previous periods.

C. Electricity networks

Following Decision 1431/2020, which revised the Methodology for calculating the Allowed Revenue and Required Revenue of the HEDNO, RAE amended the methodology for calculating the Allowable and Required Revenue of the IPTO to gradually harmonize the revenue methodologies for both electricity and gas transmission and distribution activities, obviously taking into account their specificities, towards a more modern incentives' methodology and to strengthen the criteria for improving the efficient operation of the transmission system.

The new Regulation: a) Redefines the methodology to calculate the return on capital employed for Major Importance Projects. b) Defines a distinct parameter for increasing or decreasing the Required Revenue, as a result of the application of incentives to ensure the efficient and safe operation of the System and the network operator, the stability of the System, as well as the reliable, qualitative and continuous supply of electricity, taking into account Key Performance Indicators (KPIs).

Furthermore, Decision 590/2021 defined the conditions for the classification of "Significant Transmission Projects" for which there is an obligation to carry out a Cost-Benefit Analysis (CBA), as well as the conditions for their classification as "Major Importance Projects".

Decisions 707/2021 and 707A/2021 established for the first time a complete methodology for the calculation of the Network Charges of the HEDN, based on the principles established in the Distribution Network Code, with the adoption of the Network Charges Manual. The new methodology improves the cost-effectiveness and fairness of the distribution charges, while exploiting the modern electricity consumption metering capabilities to provide effective economic signals to the users of the distribution network, with the aim of limiting peak loads and postponing or limiting investments in the Network to increase network capacity, while ensuring predictability and firmness of the Operator's revenues.

For the modernisation of the Distribution Network, the Authority has designated four Major Projects of the HEDNO and identified them as having an additional return on investment, due to the significant benefit they are expected to bring to consumers and society in general, most importantly the installation of smart metering systems ("smart meters") and the extension of telemetering.

Finally, for the first time, a Methodology for the Calculation of Guarantees for Distribution Use of Network Charges for Consumers in the Interconnected Network of the HEDN was adopted. The relevant guarantee amounts were approved from 1.10.2021 and up to the end of 2022.

Also, in 2021, RAE proceeded to issue decisions regarding: a) The consolidation of operational safety in the Continental Europe Synchronous Area, b) The establishment of the Regional Coordination Centre in Thessaloniki, c) The approval of loss factors of the distribution network, d) The approval of the Transmission Use of System Charges, e) The approval of the Ten-Year Network Development Plan (TYNDP) of the Hellenic Electricity Transmission System for the period 2021 – 2030, f) The approval of the Distribution Network Development Plan (DNDP) for the period 2021-2025, g) the adoption of the Manual of Distribution Use of Network Charges of the distribution network code, h) the adoption of the Transmission Use of System Charges Manual of the Transmission System Code.

2.2 Gas Sector

With international gas prices remaining low until summer 2021, domestic consumption increased by 11% compared to 2020 and amounted to 69.94 TWh, making it the highest demand ever recorded in Greece. Under these circumstances, interest in new infrastructure remained elevated. With the start of commercial operation of the TAP on 30 December 2020, the competition between gas importers increased, since already in the first year of operation, the gas imported through the TAP covered 19% of the country's gas needs.

In this context, the operation of a Trading Platform in the framework of building an organised gas market in the country is particularly important. During 2021, RAE worked closely with the Nominated Electricity Market Operator (HENEX) and the single gas TSO (DESFA) to establish the framework for the operation of the gas Trading Platform, on the basis of Regulation (EU) 312/2014.

By Decision 1060/2021, in consultation with the NNGS Operator (DESFA), the NNGS Code was amended so that the purchase and sale of short-term standardised products for balancing purposes would take place at the Trading Platform, upon its entry into operation, replacing the Balancing Platform. The development of the regulatory framework to achieve sufficient communication between the Trading Platform and DESFA was also required, so that the network operator is informed of the transactions made in the Platform, as it is the responsible party for the physical delivery of the gas.

By the virtue of Article 39 of Regulation (EU) 312/2014, RAE Decision 70/2021 appointed DESFA as the Forecasting Party for the NNGTS balancing zone. DESFA will receive the necessary information and consumption estimates from the Distribution System Operators, which will be processed using a specific model that will be developed, with the aim of a more accurate forecast of the daily flows to better inform users about the balancing of their portfolio.

Furthermore, after the first year of implementation of the auction scheme, the process of conducting the Annual LNG Planning at Revithoussa was evaluated, which led to an amendment of the NNGS Code and the LNG Auction Manual.

At the same time, RAE in cooperation with the Italian NRA, ARERA, and the Albanian NRA, ERE, elaborated and approved the joint proposal of the TAP Operators, DESFA and SNAM to increase the capacity of the TAP pipeline from 10 bcm to up to 20 bcm and subsequently the required projects to reinforce the national transport systems of Greece and Italy.

The construction of the IGB pipeline was not completed according to schedule, resulting in the Greek and Bulgarian Regulatory Authorities amending the Exemption Decision to postpone the start of commercial operation of the pipeline to July 2022. Until then, the gas flows from the TAP pipeline to Bulgaria via the Nea Mesimvria IP and then it is forwarded to Bulgaria through reverse flows at the Sidirokastro IP. This was a key reason for issuing two regulatory decisions to allocate the products of Conditional Capacity at the Nea Mesimvria and Kipi Entry Points, where the capacity is allocated through competitive tenders.

Regarding new infrastructure, DIORIGA GAS submitted to RAE an application for Exemption from Articles 32 and 41 of Directive 2009/73/EC, and in this context RAE approved (a) the Guidelines and (b) the call for expressions of interest for the non-binding Market Test stage, which, following an extension requested by the company, was completed on 14 January 2022.

Two NNGS projects of great importance for the regional development of the country, a high-pressure pipeline to Western Macedonia and a high-pressure pipeline to Patras, were approved in the Network Development Plan 2021-2030. Also, with the same decision, RAE requested DESFA to carry out a cost-benefit study for the extension of the NNGS in Western Greece (Epirus).

In 2021 the company HENGAS started its operation as Distribution Network Operator and was granted a Distribution License for the construction of gas distribution networks in 9 municipalities of the country, in Central and Western Macedonia, as well as in the Peloponnese. HENGAS was certified as an Ownership Unbundled operator and subsequently obtained a Gas Distribution License. The 2022-2026 Network Development Plan of HENGAS was approved. In this light, RAE also amended appropriately the Distribution Networks Code, the Tariff Regulation and the Metering Regulation.

Furthermore, it became necessary to amend Decision 643/2018, which regulated the way of supplying the Remote Distribution Networks, i.e. the networks that are not close to the NNGS and therefore have to be supplied with Compressed (CNG) or Liquefied Natural Gas (LNG) using trucks, in order to extend the concept of a 'Virtual Pipeline', which connects the Remote Network with a central network of the same Operator, to a 'Virtual Interconnection', where the CNG may come from another Distribution Network, possibly of a different Operator. In addition, the regulatory foundations were laid for the supply of LNG to the Remote Networks in view of the completion of the construction of the first LNG Truck Loading Station at Revithoussa.

RAE as the Competent Authority for the Security of Gas Supply of the country, in cooperation with the Italian Competent Authority, has taken the coordinating role for the preparation of the Joint Risk Assessment Study in the Southern Gas Corridor - Caspian risk group, in which Bulgaria, Greece, Croatia, Italy, Hungary, Malta, Austria, Greece, Croatia, Italy, Malta, Romania, Slovenia and Slovakia participate. In addition, following a proposal from the European Commission, RAE has been appointed as the coordinating authority for the preparation of the Joint Risk Assessment Study in the Trans-Balkan risk group, which includes Greece, Bulgaria, Romania and Ukraine. In this context, RAE coordinated the preparation of Joint Risk Assessment Studies for these groups.

Based on the results of the National Risk Assessment Study conducted in May 2020, RAE prepared a Preventive Action Plan (PAP), as an update of the PAP previously prepared in 2018. The Plan listed a set of measures and obligations that will contribute to further strengthening the country’s energy security in a proactive manner.

2.3 Renewable Energy Sources Sector

The increased number of new applications for the granting of Electricity Producer Certificates, as well as the intensification of RAE's licensing work, especially after the development of the special information system from December 2020, as provided for in Law No. 4685/2020 and the Regulation on Producer Certificates for Electricity from RES and HECHP (Gazette B' 5291/1.12.2020), resulted in a very large number of acts being issued by RAE, namely 4,151 decisions, despite the successive amendments to the legal framework to facilitate the licensing procedure.

In addition, in May 2021, a competitive procedure for RES generation plants took place. The auction concerned wind installations with a maximum generation capacity of up to 50 MW and photovoltaic installations with a capacity of up to 20 MW. The procedure was considered to have been particularly successful with strong competition, as the capacity tendered was exhausted and, most importantly, there was a significant price reduction from the starting prices of up to 30.2%, to the benefit of consumers and the national economy. The average weighted price of the selected projects was 37.60 €/MWh, compared to the maximum price of 53.86 €/MWh.

Finally, it should be noted that there was a very strong interest in licensing storage units. In 2021, 200 applications for storage licenses with a total capacity of about 15 GW were awarded.

2.4 Report on the implementation of the Clean Energy Package

The Clean Energy for all Europeans package, or as commonly referred to as the Clean Energy Package (CEP), is a set of eight legislative acts on electricity market design, renewable energy, energy performance of buildings and governance which was officially published in the Journal of the European Union in June 2019. In this regard, Greece has been progressively implementing the CEP by transposing the relevant EU legislation into the national legal framework.

Under the Governance Regulation (EU) 2018/1999, each EU country is required to establish an integrated 10-year National Energy and Climate Plans for 2021-30. In December 2019 the National Energy and Climate Plan (NECP), the Greek government's strategic plan for climate and energy issues, was published. The Plan sets out priorities and policy measures in respect of a wide range of development and economic activities intended to benefit Greek society, and therefore it is a reference text for the forthcoming decade. Greece, having already attained the RES objectives of 2030, is currently reviewing the NECP with the view of setting more ambitious and comprehensive goals. In October 2023, Greece notified the European Commission of the suggested NECP. Furthermore, the NECP is required to incorporate the targets of the National Climate Law 4936/2022 (Gazette A' 105/2022), the targets of the EU policy (REPowerEU and Fit-for-55) and the new trends of technology evolution (f.e. hydrogen, storage etc).

The Directive (EU) 2018/844 of the European Parliament and of the Council amending Directive 2010/31/EU on the energy performance of buildings and Directive 2012/27/EU on energy efficiency (EPBD), was fully transposed into national legislation with the Laws 4685/2020 (Gazette A' 92/2020) and 4710/2020 (Gazette A' 142/2020) in May and July of 2020 respectively.

Furthermore, in November 2020, the Ministry of Energy held a public consultation for the transposition of the Directive (EU) 2018/2002 of the European Parliament and of the Council of 11 December 2018 amending Directive 2012/27/EU on energy efficiency (EED). This Directive was transposed into the national legislation with Law 4843/2021 (Gazette A' 193/2021) in October 2021.

As of December 2021, the recast Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources (REDI) has not yet been transposed into national legislation while the Ministry of Energy is still elaboration on a draft legislative act. A public consultation is expected to be held in the first quarter of 2022 to transpose the Directive.

On 20 October 2021, Law 4843/2021 (Gazette A 193/20.10.2021) was published and among other things, transposed Directive (EU) 2018/2002 amending Directive 2012/27/EU on energy efficiency. The law regulates energy efficiency issues, the removal of barriers in the energy market, the elimination of market failures that prevent efficiency in the supply and use of energy, and the setting of indicative targets for the use of energy. Furthermore, Law 4843/2021, amending certain provisions of Law 4513/2018, facilitates the establishment of energy communities.

An important development in the RES sector is also provided for by Law 4819/2021, which introduces the obligation to provide the Regulatory Authority for Energy (RAE) with a letter of guarantee as a condition of the issuance of a producer certificate or a special projects production certificate.

Regarding the recast Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU, there was only a partial transposition while most of the articles will be transposed within 2022. In August

2021, RAE held a public consultation[1] with the energy market stakeholders to examine possible legislative and regulatory interventions to harmonize the national legislative framework with Directive (EU) 2019/944, focusing in particular on the empowerment of electricity consumers, the promotion of healthy competition between suppliers, such as providing consumers with adequate information, safeguarding their fundamental rights, strengthening the transparency as well as achieving greater comparability of the tariffs of electricity supply.

[1] For more information refer to https://www.rae.gr/diavoulefseis/12637/.

3 THE ELECTRICITY MARKET

3.1 Network regulation and technical functioning

3.1.1 Unbundling

3.1.1.1 Transmission System Operators

The Independent Power Transmission Operator (IPTO S.A.) is the single electricity Transmission System Operator (TSO) acting in Greece. In 2017 IPTO S.A. changed from the Independent Transmission Operator (ITO) model to the Ownership Unbundling (OU) model as a consequence of its changed ownership structure from 100% Public Power Corporation S.A. (PPC) to 51% ADMIE SYMMETOCHON S.A. (Energiaki Holding), 25% DES ADMIE S.A. and 24% STATE GRID EUROPE LIMITED (SGID).

The new certification procedure regarding the certification of TSOs in relation to 3rd countries under Article 11 of the Electricity Directive 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 IPTO including the obligation that any future development[2] would need to be notified to RAE underpinned also by adequate reasoning for continuous compliance with the unbundling requirements, such as security of supply criteria.

RAE continued monitoring the correct application by IPTO of the aforementioned conditions throughout 2021 with IPTO submitting an annual report concerning its compliance with the Electricity Directive.

3.1.1.2 Distribution System Operators

Currently, in Greece there is only one DSO, the Hellenic Electricity Distribution Network Operator (HEDNO S.A. or DEDDIE S.A.), which is a 100% subsidiary of PPC S.A. and is responsible for the development, operation and maintenance of the Hellenic Electricity Distribution Network (HEDN). PPC S.A. remains the owner of the Distribution Network assets. HEDNO is also the Power System and Market Operator for the Non-Interconnected Islands of the country.

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. 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 "HEDNO S.A.".

[2] For example, regarding the activities of SGID, its mother company and in general Chinese projects in Greece and Europe, or any change in control over IPTO.

3.1.2 Network extension and optimization

In July 2020, IPTO S.A. submitted to both RAE and the Bulgarian Regulatory Authority a proposal for the creation of the Regional Coordination Center (RCC) for the South-East Europe (SEE) System Operation Region (SOR), to replace the existing RSC SEIeNeCC, as defined in article 35 of Regulation (EU) 2019/943.

RAE, with Decision 117/2021 (Gazette B' 832/03.03.2021), approved TSOs' proposal to establish a RCC in the Southeastern European region where the TSOs of Bulgaria, Greece, Italy and Romania will participate (ESO-EAD, IPTO S.A., Terna SpA and Transelectrica). Following the provisions of Regulation (EU) 2019/943, TSOs establish, at first, Regional Security Coordinators (RSCs), which are companies owned by the former and ensure operational security of the electricity system at European level.

RAE, with its Decision 590/2021 (Gazette B' 4774/18.10.2021), approved the Manual for National Electricity Transmission System operation "Guidelines for drafting Cost-Benefit Analyses (CBA) for projects to be incorporated into the National Electricity Transmission System". With the aforementioned Decision, the conditions for the designation of "Important Transmission Projects" for which there is an obligation to prepare a Cost-Benefit Study, as well as the conditions for the designation of Projects of Utmost Importance (PUI), were defined.

RAE, with its Decision 611/2021 (Gazette B' 410/03.02.2022), approved the revised Ten-Year Network Development Plan (TYNDP) 2021-2030, as submitted by IPTO S.A. in June 2021. More specifically, this Decision includes conditions and amendments concerning specific projects of the TYNDP, their construction schedule and some of their properties. Concerning the new international interconnection projects proposed by the TSO with Italy, Turkey, Albania and the upgrading of the existing interconnection with North Macedonia, it is emphasized that they will be approved in order to be included in the National Electricity Transmission System, on the condition of submitting a CBA, according to RAE's Decision 590/2021.

RAE, with its Decision 631/2021 (Gazette B' 410/16.09.2021), approved the Network Development Plan 2021-2025. With this Plan, multiple important modernization projects are planned for the National Electricity Distribution Network, such as the installation of smart meters for all LV consumers, strengthening network's resilience in forested areas and other projects, which will increase RES generation. Network Development Plan 2021-2025 includes projects with a total budget of 2.5 billion euros, with planned investments of 1.7 billion euros during that period.

3.1.3 Network tariffs

RAE has been approving the tariffs for access to both the national distribution and transmission electricity networks since 2011 under the auspices of Law 4001/2011, article 140. The approval decision occurs one month before the tariffs enter into force, based on the proposals submitted to the Regulator by the Electricity Transmission Network and Distribution System Operators, IPTO S.A. and HEDNO S.A. respectively.

3.1.3.1 Transmission Network Operator – IPTO S.A.

In the process of approving the Allowed Revenue, RAE validates TSO's proposal based on historic performance, future trends and approved development plans (TYNDP). The Required Revenue, which is based on the Allowed Revenue adjusted with any deviations from the initial estimated amounts, is then allocated to the different consumer categories. RAE, with its Decision 179/2021 and according to the approved Allowed Revenue (AR) for 2021 (Decision 235/2018) set the TSO's Required Revenue (RR) for 2021 at 211.6 million euro.

in €	2021
Allowed Revenue (AR)	285,895,000
Under/Over Recovery (P1)	142,810
Adjustments due to over/under investment (depreciation and allowed return) of previous years (P2)	-6,141,261
Revenues from Interconnection Capacity Rights (P3)	-66,179,594
Inter-Transmission System Operator Compensation mechanism -ITC (P4)	1,906,410
Revenues from Non-Regulatory Activities (P6)	-9,699,060
ARIADNE Interconnection expenses (OPEX during construction)	5,672,640
Required Revenue 2021 (RR)	**211,596,945**

Table 1: Required Revenue of National Transmission System 2021 in real terms based on RAE Decision 179/2021 (amounts in €)

RAE with its Decision 178/2021, approved the use of the congestion income (36,369,871.74 €) according to Regulation 943/2019 based on the methodology of the Allowed Revenue, Decision 340/2014 for 2021.

The key financial figures of IPTO in the last 5 years (actual amounts for 2017-2021), according to annual financial statements and RAE Decisions for the approval of the Required and Allowed Revenue are the following:

in million €	2017	2018	2019	2020	2021
Revenues from Use of System Charges	236.9	194.9	229.1	273.6	270.36
Net Revenues before tax	82.9	108.9	134.8	122.1	88.99
Approved Allowed Revenue of Transmission System	260.9	233.9	252.4	281	285.9
Approved Required Revenue of Transmission System	202.6	197.5	198.9	198.5	211.6

Table 2: Key financial figures of IPTO S.A.

In June 2021, the methodology for calculating the Allowed and Required Revenue of the Electricity Transmission Network Operator was amended (Decision 495/2021). The most critical changes, in comparison to the previous applied cost-plus methodology (Decision 340/2014) were the:

- Calculation of TSO's Allowed Revenue (AR) in nominal terms.
- Operational expenditures (OPEX) were distinguished into controllable and non-controllable.
- Rate of return based on nominal pre-tax Weighted Average Cost of Capital (WACC).
- Amendments regarding the framework of incentives to Major Importance Projects (MIPs).

After taking into account the conditions in the energy market and the developments taking place in the last years, such as RES integration and changes in the system load, RAE deemed necessary to update the methodologies which determine the Transmission Use of System Charges. This change will help towards the better implementation of the cost-reflectivity principle and will provide more efficient signals for the consumers, to help limit the peak load and thus reduce the need for reinforcing the System and its long-term cost. However, the procedure for amending and updating the methodologies was completed at the end of 2021, therefore tariffs for 2021 were based on the same methodology that applied also in previous years. According to this methodology:

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

- Tariffs for HV consumers follow a €/MW structure, charged on the consumer's average hourly demand during the following three hours: system summer peak, system winter peak and the maximum of the two.
- For the purposes of the transmission use of system charging (TUoS), the following four (4) consumer categories are classified: 1. Medium Voltage (MV) consumer, 2. Household consumer, 3. Household consumer 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 consumers, 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 Household consumers with KOT are charged a simple €/MWh energy charge (no capacity-based charge for TUoS). For Household consumers (except for Household consumers 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 consumers, 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.

The following table presents the Transmission System user tariffs based on the Required Revenue of 2021 (RAE Decision 179/2021), based on IPTO's proposal. Those charges have been applied since 1st August 2021 based on Decision 492/2021.

Consumers Category	**Capacity charge**	**Energy charge**
Large Consumers HV	23,560 €/MW /per year	-
Consumers MV	1,384 €/MW Peak time/ month	-
Households LV	0.13 €/kVA per year	0.0056 €/ kWh
LV – Vulnerable consumers	-	0.0062 €/ kWh
LV others*	0.51 €/kVA per year	0.0052 €/ kWh
**This category includes street lighting*		

Table 3: Regulated Tariffs applied for the use of the transmission system in 2021.

The Weighted Average Cost of Capital (WACC) parameters were thoroughly analyzed in compliance with Article 10 of the Tariffs' Methodology. RAE carefully considered vital market data, data repositories monitoring key market indicators, drawing insights from international best practices and reliable sources, and estimates from esteemed entities like the International Monetary Fund (IMF), the European Commission, and the Hellenic Statistical Office. The main parameters of WACC are presented in Table 4.

	2018	2019	2020	2021
Risk-free rate	0.7%	0.7%	0.7%	0.7%
Market Risk Premium	5.0%	5.0%	5.0%	5.0%
Asset Beta	0.43	0.43	0.43	0.43
Gearing ratio (loan)	36.3%	41.35%	36.27%	40.30%
Equity Beta	0.68	0.73	0.67	0.72
Equity Return	4.1%	4.4%	4.1%	4.3%
Country Risk Premium	2.3%	2.0%	1.8%	1.5%
Cost of equity (post-tax)	6.4%	6.4%	5.9%	5.8%
Tax rate	29%	29%	29%	29%
Cost of equity (pre-tax)	9.0%	9.0%	8.3%	8.2%
Debt rate	5.28%	5.6%	5.04%	5.13%
Total WACC (nominal, pre-tax)	7.64%	7.6%	7.1%	6.95%
Inflation	0.6%			
Total WACC (real, pre-tax)	7.0%	6.9%	6.5%	6.3%

Table 4: Main parameters of WACC- IPTO S.A. - 2018-2021 (Decision 235/2018)

3.1.3.2 Distribution System Operator – HEDNO S.A.

The Methodology for calculating the Allowed Revenue and Required Revenue of HEDNO was approved by RAE with its Decision 1431/2020. In this Methodology incentive mechanisms were introduced to improve the efficiency of the DSO. In particular, an incentive mechanism for controllable operational expenditure (Opex efficiency incentive mechanism) is introduced, commencing from the 1st Regulatory Period, that aims to gradually reduce the operating costs for HEDN users between Regulatory Periods, as well as sharing the relevant benefit from the expenditure saving between the Operator and HEDN users within the Regulatory Period in which the saving occurs. Also, the parameters affecting the outcome of the incentive mechanisms foreseen in the HEDN Code for the reduction of Network energy losses and the improvement of Distribution service quality were considered in the methodology. Another significant methodological matter that was considered is the characterization of Major Importance Projects (MIPs), that is based on a fully justified proposal (cost-benefit analysis) and the provision of an incentive in the form of a return premium, which may range from 0.5% to 2% for a period of 4 to 7 years.

Taking into consideration that the Required Revenue methodology for the Regulatory Period 2021-2024, established with RAE's Decision 1431/2020, is applied on a transitional basis, the previous methodology, prescribed in RAE's Decision 840/2012, remains in force.

RAE, with its Decision 632/2021, approved the Allowed and the Required Revenue of the Distribution Network Operator for 2021 setting the Allowed Revenue at 776 million € (2020: 758 million €) and the Required Revenue at 777.3 million € (2020: 751.4 million €). Furthermore, RAE Decision 1566/2020 set the WACC for HEDNO at 6.7%, in accordance with Articles 15 and 140(3) of Law 4001/2011, as well as the stipulations outlined in Article 125 of the HEDN Code, Article 180 of the NII Code and Article 16 of the HEDN Tariffs' Methodology.

The key financial figures of HEDNO in the last 5 years (2017-2021), according to annual financial statements and RAE Decisions for the approval of the Required and Allowed Revenue are the following:

in mil €	**2017**	**2018**	**2019**	**2020**	**2021**
Revenues from Network Use Charging	740.9	711.1	727.8	710.8	727.1
Net Revenues before tax	36.7	-17.83[4]	99.4	26.03	19.12
Approved Allowed Revenue of Distribution System	753.7	743.6	753.4	758	776
Approved Required Revenue of Distribution System	741.7	752.8	743.6	751.4	777.3

Table 5: Key financial figures of HEDNO S.A.

in k. €	**2021**	**2022**	**2023**	**2024**
Controllable OPEX	450,015	448,568	440,171	444,796
Non-Controllable OPEX	6,596	8,576	7,870	7,682
Depreciation	143,772	148,488	152,516	163,484
Allowed Return on RAB	194,917	193,834	194,197	197,062
Allowed return on the capital employed by the Distribution activity for Major Importance Projects	696	2,563	6,518	12,507
Revenues from other regulated and non regulated activities	-20,011	-20,178	-20,376	-20,693
Total Allowed Revenue	**775,984**	**781,851**	**780,897**	**804,837**

Table 6: Allowed Revenue 2021-2024 for HEDNO S.A.

[4] Financial Statements HEDNO 2018. The significant decrease of net revenues before tax compared to 2017 is attributed to provision of 58.1 million euros for compensation of departing staff (Law 4533/2018).

	2021	2022	2023	2024
Risk-free rate	0.45%	0.45%	0.45%	0.45%
Market Risk Premium	5.50%	5.50%	5.50%	5.50%
Gearing ratio (loan)	39.10%	39.10%	39.10%	39.10%
Equity Beta	0.80%	0.80%	0.80%	0.80%
Equity Return	4.85%	4.85%	4.85%	4.85%
Country Risk Premium	1.50%	1.50%	1.50%	1.50%
Cost of equity (post-tax)	6.35%	6.35%	6.35%	6.35%
Tax rate	24%	24%	24%	24%
Cost of equity (pre-tax)	8.36%	8.36%	8.36%	8.36%
Debt rate (pre-tax)	4.11%	4.11%	4.11%	4.11%
Total WACC (nominal, pre-tax)	6.69%	6.69%	6.69%	6.69%

Table 7: Main parameters of WACC- HEDNO S.A. - 2021-2024 (Decision 1566/2020)

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

For calculating charges on consumers using the Distribution Network code, 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 household consumers, and other non-household LV consumers.

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

Tariffs were not updated in 2021, therefore the tariffs set by RAE's Decision 2/2020, applied since 1st April 2020, remained in effect throughout the year (see Table 8).

Consumers Category	Capacity Charge	Energy charge
Consumers MV	1,097 €/MW Peak Demand /month	0.0028 €/kWh
Consumers LV (over 25 kVA), based on the calculation of the maximum supply and taking into consideration the non-used power	3.98€/kVA subscribed capacity, charged per year	0.0173 €/kWh
Consumers LV (over 25 kVA), based on the calculation of the maximum supply and non-taking into consideration the non-used power	2.72€/kVA subscribed capacity, charged per year	0.019 €/kWh
Consumers LV	0.52 €/kVA subscribed capacity, charged per year	0.0213 €/kWh
Consumers (vulnerable consumers)	-	0.0237 €/kWh
Others LV (maximum 25 kVA)	1.46 €/kVA subscribed capacity, charged per year	0.019 €/kWh

Table 8: Regulated tariffs applied for the use of the distribution system in 2020 and 2021 (from 1st April 2020)

3.1.4 Security and reliability regulation

To safeguard grid operation and the competences of national regulatory authorities, the Regulation establishing a guideline on electricity transmission system operation (SOGL) offers comprehensive rules: (a) Defining criteria and principles for ensuring operational security, (b) Establishing protocols and obligations for TSOs to coordinate and share data with each other, with DSOs, and with SGUs during both planning and real-time grid operations, (c) Setting benchmarks and procedures for training and certifying personnel responsible for operating the system, (d) Requiring adherence to specific protocols for coordinating outages to minimize disruptions, (e) Specifying requirements for coordinating scheduling activities between control areas managed by different TSOs, (f) Introducing regulations for establishing a Union-wide framework for managing load-frequency control and reserves. Under this framework, each national regulatory authority holds the responsibility of approving the terms, conditions, or methodologies developed by TSOs to ensure compliance with these regulations.

In this context, following a public consultation that was held between 27 October 2020 and 13 November 2020, RAE implemented Decision 77/2021, addressing the essential additional characteristics of the FCR necessary to uphold operational security within the synchronous area, as outlined in Article 154(2) of Commission Regulation (EU) 2017/1485. The FCR additional properties as determined in Decision 77/2021 supplement the requirements of Article 154 of the SO Regulation for FCR providing units and FCR providing groups.

3.1.5 Monitoring balance of supply and demand

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 Consumers), 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 further strengthened its 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:

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

In this context, RAE, at the end of 2018 developed a financial-methodological tool/application (retail monitoring tool) in order to automate the process of collecting and processing data from suppliers and operators. The tool was completed in the end of 2019 accompanied by the relevant letters and usage manuals which were shared to the Suppliers and electricity and natural gas Operators in 2020. This Tool collects:

1. The supply of electricity and natural gas in the retail market, including detailed information on the bill charges, overdue debts, switching and disconnection applications.
2. Financial viability (total revenues and costs) from the supply and production of electricity, aiming at controlling the profitability of the participants in the relevant retail market.
3. Electricity and natural gas distribution data from the DSOs (number of metering points, consumption per supplier, switching and disconnection applications and order execution for the DSO given by the Suppliers).

4. Data on consumers' complaints and management of requests

The main objective of the retail monitoring tool is to validate that the Suppliers' tariffs reflect the real cost of supply plus a reasonable profit, to identify any cross-subsidies between tariffs of different consumer categories, to avoid discrimination between consumers of the same category in order to avoid competition distortion and ensure healthy growth in the energy retail markets. The first implementation of the Tool took place in 2020 when its interoperability was tested and its main strengths and weaknesses were designated. In the last quarter of 2020, the Tool's required updating procedures were initiated which will be concluded in 2021 when its second edition will be shared to the relevant bodies (electricity and natural gas Suppliers and Operators) with the updated usage manuals.

3.1.6 Cross-border issues

In 2021, RAE published its Decision 384/2021 on the interpretation and application of RAE's Decision 847/2017 "Cross-Border Cost Allocation (CBCA) of the Project of Common Interest "EUROASIA Interconnector" between Greece and Cyprus", following the update of the European Union List of Projects of Common Interest, with Regulation 2020/389.

This update concerns:

- The reformulation of term definitions "Project" or "PCI" of the CBCA agreement of October 10, 2017
- The implementation schedule of PCI 3.10.2
- Ensuring the interoperability of PCI 3.10.2 with the National Transmission System

The confirmation of the already agreed cross-border cost allocation, which means that 37% of the agreed implementation costs (according to the CBCA Agreement of 10 October 2017) of this sub-project are distributed to Greece and 63% to Cyprus, assuming that the project will be subsidized by 50% from third parties.

3.1.7 Implementation of Network Codes and guidelines

(A) In 2021, RAE, within the framework of Regulation (EU) 2015/1222 concerning the capacity allocation guidelines and congestion management (CACM), published the following Decisions:

1. Decision 55/2021 on the approval of the common capacity calculation methodology in GRIT CCR, according to Articles 20 and 21 of Regulation (EU) 2015/1222 of the Commission of 24 July 2015, concerning the guidelines setting for capacity allocation and congestion management.

2. Decision 123/2021 on the amendment of the common SEE CCR capacity calculation methodology, according to Articles 20 and 21 of Regulation (EU) 2015/1222 of the Commission of 24 July 2015, concerning the guidelines setting for capacity allocation and congestion management.

3. Decision 239/2021 concerning the determination of fallback procedures for GRIT CCR, according to Article 44 of Regulation (EU) 2015/1222 of the Commission of 24 July 2015, concerning the guidelines setting for capacity allocation and congestion management.

(B) In 2021, RAE, within the framework of Regulation (EU) 2016/1719 establishing a guideline on forward capacity allocation (FCA), published the following Decisions:

1. Decision 861/2021 concerning the approval of GRIT CCR TSOs' common proposal for the regional requirements for the harmonized allocations rules according to Articles 51 and 52 (3) of Regulation (EU) 2016/1719 of the Commission of 26 September 2016 concerning the guidelines setting for future capacity allocation.

(C) In 2021, RAE, within the framework of Regulation (EU) 2017/2195 concerning the establishing of a guideline on electricity balancing (EB), published the following Decisions:

1. Decision 519/2021 on the approval of the GRIT CCR TSOs joint proposal for a methodology on a market-based allocation process of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves, pursuant to Article 41 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing.

2. Decision 520/2021 on the amendment of the GRIT CCR TSOs joint proposal for a methodology for the allocation of cross-zonal capacity based on an economic efficiency analysis, pursuant to Article 42 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing.

(D) In 2021, RAE, within the framework of Regulation (EU) 2017/1485 concerning the establishing of a guideline on electricity transmission system operation (SOGL), published the following Decision:

1. Decision 77/2021 on common additional properties of the FCR required to ensure operational security in the synchronous area pursuant to Article 154 (2) of Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation.

3.2 Competition and market functioning

3.2.1 Wholesale markets

3.2.1.1 Description of the wholesale market

The electricity spot market in Greece was reformed starting the 1st of November 2020, according to the provisions of RAE's Decision 1298/2020[5] (Gazette B'4415/07.10.2020). A new wholesale electricity market design, in line with the European Target Model, replaced the day-ahead mandatory pool system, which was in operation since 2005.

Following proposals made by RAE and the competent Operators, in cooperation with the Ministry of Energy, Law 4425/2016, as amended by Law 4512/2018, came into force, according to which the following four separate markets have been established: A) Energy Derivatives Market, B) Day-Ahead Market, C) Intra-Day Market, and D) Reserves and Energy Balancing Markets.

The Energy Derivatives Market started operation in March 2020 and the three spot electricity markets started operation on November 1, 2020. The first three markets are operated by the Hellenic Energy Exchange (HENEX SA), whereas the Balancing Market is the exclusive responsibility of IPTO. The Hellenic Energy Exchange has been designated as the Nominated Electricity Market Operator (NEMO) for the coupling of the day ahead market and the coupling of the single intraday electricity market (RAE Decision 1124/2019).

A) Energy Derivatives Market: The Energy Derivatives Market's organization and support of its transactions is carried out by HENEX SA, while the settlement of transactions, having the role of the central counterparty (CCP), is carried out by ATHEXClear, one of the member companies of the Hellenic Energy Exchange. The futures contracts are traded in the Energy Derivatives Market, which relate to the exchange of electricity by determining the time, quantity and price of the transaction with physical delivery obligation as an option and can be concluded either bilaterally (OTC) or through an organized Energy Exchange (Forward Market). The futures market is a useful tool for participants in order to mitigate their exposure to price volatility in energy markets where there is a physical delivery obligation.

B) Day-Ahead Market (DAM): The DAM is an hourly spot market balancing demand and supply via electricity prices, reflecting the highest generation bid needed to meet the lowest willingness to pay of load representatives. Participants submit electricity transaction (buy/ sell) orders (per unit in the case of conventional producers, per portfolio in the case of RES producers or aggregators and per Bidding Zone or Border in the case of other Market Participants) with the obligation of physical delivery on the next day. Participants declare the energy quantities to be delivered physically corresponding to forward-market product transactions. Producers are obliged to submit orders for capacity that has not been allocated via the forward contracts with physical delivery nominations. The outcome of the DAM is a market schedule submitted to the system operator for physical implementation the next day either at a unit/ entity level (for conventional thermal, hydro units and interconnections) or portfolio (for suppliers and aggregators).

C) Intraday market (IDM): This market allows participants (same participants as in the DAM and for traders under the existence of relevant explicit Physical Transmission Rights) to place transaction orders for physical delivery in order to modify their position in the generation schedule, load declarations, etc., close to the time of the physical delivery, taking into consideration the energy quantities committed through forward electricity products, the DAM schedule as well as any events and deviations and limitations emerging from the balancing market, in an aim to reduce their

[5] See http://www.rae.gr/site/categories_new/about_rae/factsheets/2020/gen/1109.csp.

exposure to imbalances costs. The transactions in the IDM concern upward and downward changes, and their financial settlement is based on market equilibrium prices that are common for upward and downward changes. The IDM launched in 2020 included three local intra-day auctions (LIDAs) per day and participation is voluntary.

D) Balancing Market (BM): The Balancing Market includes the following: i) the Balancing Capacity Market (BCM) to ensure that sufficient reserves are available, ii) the Balancing Energy Market (BEM) to activate energy in real time to ensure that the system is in balance while meeting demand for energy and reserves and respects all technical plant operation constraints, and iii) the Imbalance Settlement (IS) to allocate the costs of the Balancing Market to market participants. Generators are required to submit bids with a physical delivery obligation for their total available capacity, both in the Balancing Energy market and the Balancing Capacity Market. The following table presents an overview of the main elements in the design of the Balancing Markets.

Name of the procedure	Integrated Scheduling Process (ISP algorithm)	Balancing Energy Market (RTBM algorithm)	Settlement of Balancing Energy & Capacity, and Imbalances
Time resolution	30 minutes	15 minutes	15 minutes
Objective	Balancing capacity procurement	Balancing energy procurement	Metering and Settlement
Ancillary services	FCR, aFRR, mFRR	aFRR, mFRR	
Remuneration rule	Capacity remunerated pay-as-bid	aFRR remunerated pay-as-bid mFRR remunerated at market clearing prices	Single Imbalance price Volumes, prices and settlement amounts calculated
Real time operation	Unit Commitment Schedule (from the ISP)		

Table 9: Overview of the design of the Balancing Market in Greece

Participation and bids in the BCM take place day-ahead. The TSO defines the volume of reserve requirements for each balancing capacity (reserve) product, namely for FCR (Frequency Containment Reserve), up and down, aFRR (automatic Frequency Restoration Reserve), up and down, mFRR (manual Frequency Restoration Reserve), up and down, except for RR (Replacement Reserve) which does not apply in Greece. The participants submit their offers for balancing capacities in the ISP. The ISP procedure runs at least three times daily, namely once after clearing the DAM and after the first LIDA, and twice after the other two LIDAs. For balancing capacity awarded to them, the bidders receive as compensation an amount calculated using their offer price; i.e. a pay-as-bid auction applies. Upon selection, they have an obligation to commit to the respective capacity as a reserve. Otherwise, they are not compensated for the awarded capacities resulting from the ISP results since the remuneration considers the real-time availability as indicated from the real-time operation (SCADA system).

The result of the ISP procedure is a commitment schedule of the power plants, the awarded capacities and an indicative generation schedule. The ISP algorithm applies a central scheduling – central dispatch design. It takes as given the market schedule (generation schedule of the DAM as modified by the IDM), considers in detail the technical plant operation constraints, the reserve requirements, the network constraints and the load and RES forecasts, and produces a commitment schedule that meets the calculated imbalances (also for RES and load forecasts that differ from RES and load amounts included in the DAM and the intra-day trading) and the reserve requirements at a minimum total cost, based on the participants' bids.

Close to real-time, the IPTO estimates the need for upward or downward balancing energy to activate, depending on events that drive a frequency restoration process. The activation for both the automatic and manual frequency restoration reserves is based on the balancing energy merit order, i.e. ascending (descending) prices corresponding to upward (downward) balancing energy bids. Thus, the activation of balancing energy combined with system operation constraints implies changes in electricity generation (re-dispatching), upwards and downwards, for which generators receive remuneration, defined at a market-clearing marginal price for the activated balancing energy needed to meet mFRR, and according to a pay-as-bid rule for the aFRR. More specifically, the higher (lower) accepted bid in the mFRR procedure sets the marginal price for the upward (downward) mFRR balancing energy. Regarding the aFRR, the BSPs receive at least the price of the mFRR balancing energy (of the same direction) or the price of the offer of the last accepted bid step if higher.

The Imbalance Settlement is an ex-post market procedure, which determines the settlement values (revenues and/or payments) of Balancing Responsible Parties (BRPs) and Balancing Service Providers (BSPs). The imbalance settlement period has already been set to 15 minutes since 1st November 2020. The imbalance price is the weighted average price of activated balancing energy in the relevant direction (upward or downward) for manual and automatic frequency restoration reserve. The Imbalance Price per Imbalance Settlement Period is calculated as the weighted average price of the activated Balancing Energy for manual and automatic FRR for that Imbalance Settlement Period in the predominant direction (upward or downward). If there has been no activation of balancing energy, the imbalance price reflects the value of avoiding balancing energy activation. Bids accepted for non-energy balancing purposes in real-time (e.g. re-dispatching or for voltage control) are not taken into account in the imbalance price calculation and are paid-as-bid. Any additional cost (difference of bid price and imbalance price) is recovered through an uplift account that ensures financial neutrality of the TSO.

3.2.1.2 Installed Capacity and Generation

In 2021, the installed capacity in the interconnected system of Greece was increased (20,180 MW) compared to 2020 (19,756 MW), due to the increase of RES units' installed capacity from 7,470 MW in 2020 to 8,924 MW in 2021, while the natural gas units' installed capacity remained the same as in 2020 (5,213 MW). The installed capacity of lignite units amounted to 2,816 MW, while the Large Hydro capacity remained at 3,171 MW in 2021. In terms of installed capacity (excluding RES), PPC S.A. held a market share of 69.82% compared to 72.49% in 2020.

Installed capacity and production by fuel, in 2021	Installed capacity (MW)	Total annual production (TWh)	Share in produced volume, including RES (%)
Lignite	2,872	5.34	11%
Large Hydro (P > 15 MW)	3,171	5.29	11%
Natural gas	5,213	20.87	44%
Total Thermal + Large Hydro (1)	11,256	31.51	66%
Total RES (Grid + Network) (2)	8,924	16.05	34%
Total (1+2)	20,180	47.56	100%

Table 10: Installed Capacity and Production by fuel, including RES, in the Interconnected System in 2021

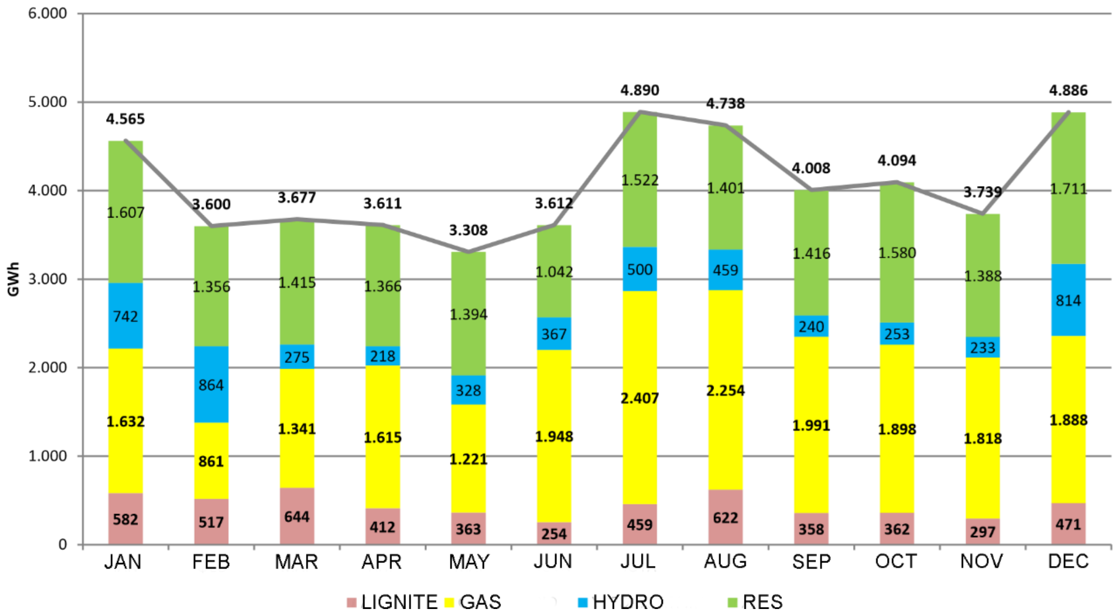


Figure 1: Monthly Production by Generation Fuel in 2021

In terms of the generation mix, in 2021 the lignite production showed a decrease of 7% (5,34 TWh) compared to 2020 (5,72 TWh). Regarding other technologies, the electricity generation from natural gas increased to 20.87 TWh (an increase of 14.7% compared to 2020, 17.81 TWh), while hydroelectric production increased by 45.2%, amounting to 5.3 TWh in 2021 (from 2.9 TWh in 2020). Finally, RES and HECHP generation continued the upward course of the previous year and reached 16.05 TWh, recording an increase of 16% compared to 2020. Overall, domestic production showed an increase of 15.44% reaching 47.56 TWh compared to 41.2 TWh in 2020.

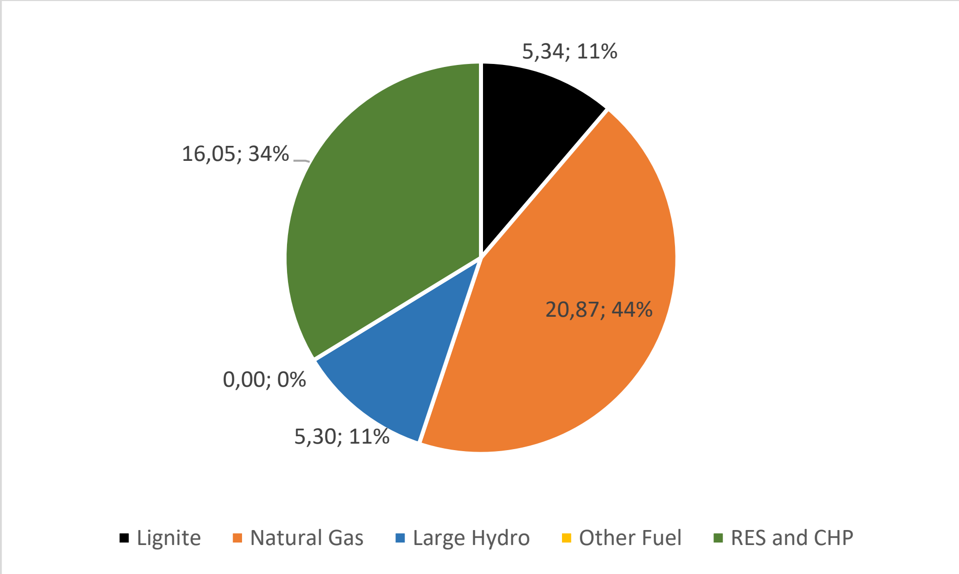


Figure 2: Electricity generation in TWh by energy source in 2021

On a monthly basis, generation from lignite showed a sharp fluctuation between 253 GWh and 644 GWh. June was the month with the lowest demand for lignite-based power while March was the month with the highest demand in 2021. Electricity generation from natural gas showed a sharp fluctuation between 860 GWh (February) and 2,406 (July) GWh. RES generation also showed greater fluctuations compared to 2020 (between 1,042 GWh in June and 1,711 GWh in December 2021). The balance of interconnections of physical electricity flows in 2021 decreased by 143% compared to 2020 and amounted to 3.6 TWh in 2021 (8.8 TWh in 2020). The fluctuations of electricity imports and exports through interconnections (Figures 3 & 4) were significant over 2021, with the lowest value being recorded in December 2021 (-175 GWh) and the highest value in July 2021 (749 GWh).

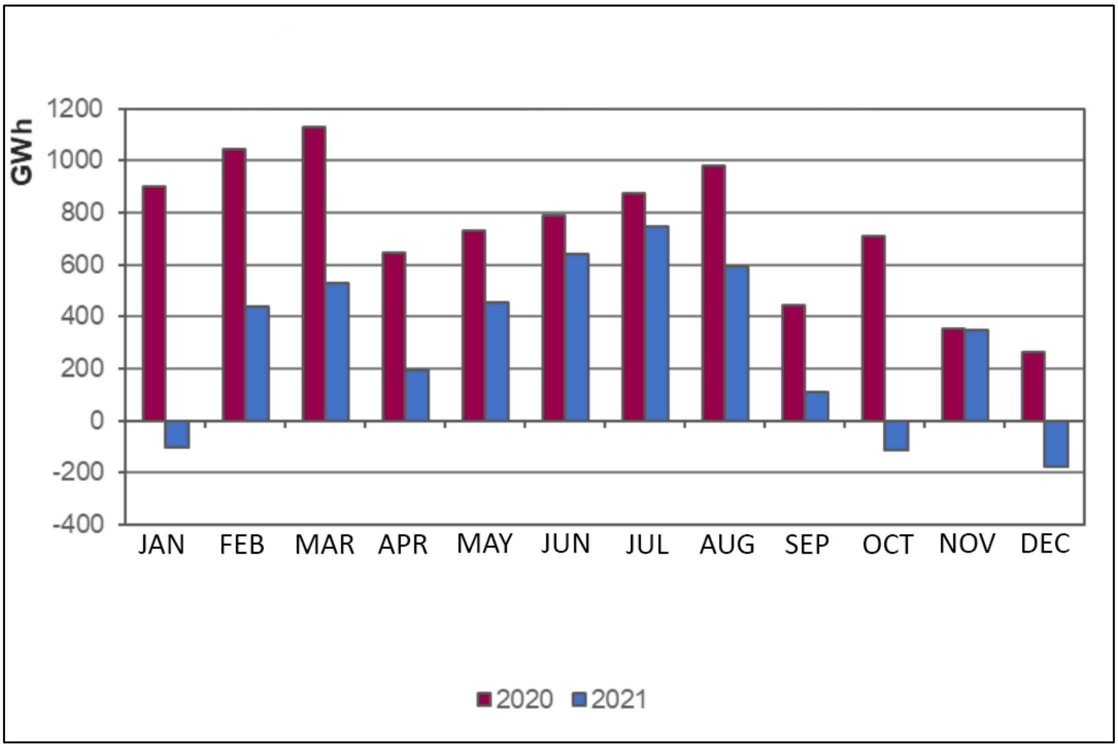


Figure 3: Evolution of Electricity Trading Balance of physical flows at interconnection points during 2020 and 2021 (GWh)

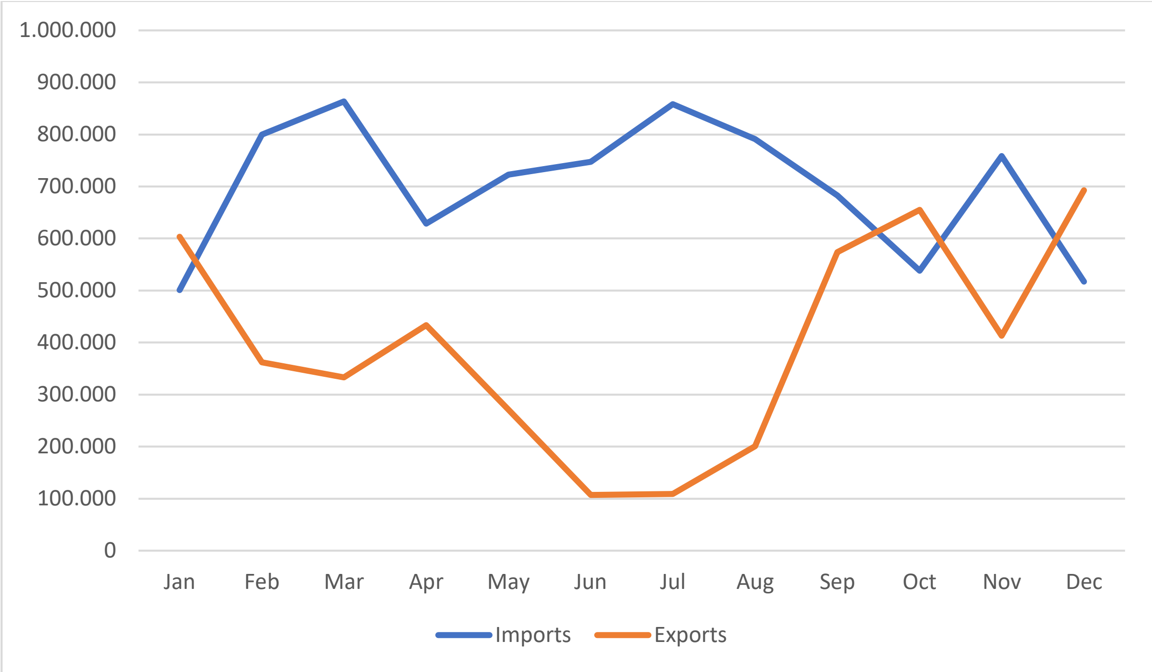


Figure 4: Physical Electricity Imports and Exports (MWh) 2021

3.2.2 Retail market

3.2.2.1 Market opening and competition

The electricity retail market has been fully liberalised since July 2013. However, there are still regulated tariffs for the consumers under Public Service Obligations, such as those under Social Tariffs, the Supplier of the Last Resort and the Universal Service Providers.

With Decision 692/2011 (and, subsequently, in the new Electricity Supply Code), RAE determined 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 take account of 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, by considering the specific characteristics of each consumer.

In December 2021 there were 21 active electricity Suppliers (including the Supplier of Last Resort and the 5 Universal Service Providers). The companies GREEN and PETROGAZ S.A. ceased their supply activity within 2021. The five suppliers with the largest market share in the electricity market have been designated by the Ministry of Energy as the Universal Service Providers.

Supplier Name:

1. PPC
2. GREEN
3. ELINOIL
4. ELTA
5. ELPEDISON
6. ZENITH
7. HERON
8. KEN
9. PROTERGIA
10. NRG
11. OTE ESTATE
12. PETROGAZ
13. UNIVERSAL SERVICE PROVIDER (PPC S.A.)
14. UNIVERSAL SERVICE PROVIDER (MYTILINEOS S.A.)
15. UNIVERSAL SERVICE PROVIDER (ELPEDISON S.A.)
16. UNIVERSAL SERVICE PROVIDER (HERON S.A.)
17. UNIVERSAL SERVICE PROVIDER (NRG S.A.)
18. SUPPLIER OF LAST RESORT (ELPEDISON S.A.)
19. FYSIKO AERIO ELLADOS
20. VOLTERRA
21. VOLTON
22. WATT & VOLT
23. WE ENERGY
24. VIENER
25. VIOLAR

26 K.V MARKOU

27 SOLAR ENERGY _ SOUMPASIS

3.2.2.2 Prices for household consumers

Prices for all electricity consumers have been fully liberalised 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 by the Universal Service Providers.

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).

The Electricity Supply Code determines the general principles for price setting in the competitive market. Per these principles, prices should be simple, transparent, cost-reflective and avoid cross-subsidies; they must take account of 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, by considering the specific characteristics of each consumer.

All suppliers publish their prices on their websites, while RAE regularly publishes comparative estimates for household and small commercial consumers under the various prices on offer (both by PPC and by the 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 Consumers), 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 further strengthened its 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

In Greece, the electricity suppliers can set the prices both in the interconnected and non-interconnected markets. For the supply of retail household consumers, there are no regulated supply prices apart from the social residential tariffs that are offered to vulnerable consumers as well as consumers that are being supplied under the SOLR and Universal Services.

There are two categories of beneficiaries that receive social residential prices, the category of KOT A, which includes very vulnerable household consumers, and KOT B which includes vulnerable consumers based on their income. The consumers that are under the KOT A category receive a discount of 0.075 €/kWh to the competitive price offered by their supplier. On the other hand, the consumers under KOT B, receive a discount of 0.045 €/kWh. As a hypothetical example where a supplier offers electricity at 0.085 €/kWh, a consumer under KOT A social prices will pay 0.01 €/kWh and a second consumer under KOT B' 0.04 €/kWh. We do not consider that this mechanism hinders the competition in the electricity market as social residential prices are offered by all electricity suppliers. Furthermore, there are quarterly electricity consumption thresholds for social residential prices.[6] The consumers under electricity social residential prices pay all related network charges, the PSO levy, the RES levy (ETMEAR) and taxes as normal consumers except for the consumers that are under KOT A social residential prices who are exempted from transmission and distribution network charges. The costs of the above-mentioned discount are covered by the PSO levy which is paid by all consumers based on their consumed electricity.

The retail residential prices increased in the fourth quarter of 2021 following the increase of the wholesale electricity prices from the summer of 2021. In particular, according to Eurostat the electricity prices[7] for household consumers with an average annual consumption between 2,500 and 5,000 KWh (DC band) increased from 0.1285 €/KWh in the first half of 2020 to 0.1305 €/KWh in the first half of

[6] Additional information on social residential tariffs as well as the beneficiaries of social tariffs can be found in English at HEDNO S.A. website: https://deddie.gr/en/upiresies/eidika-timologia/koinwniko-oikiako-timologio/
[7] The electricity prices do not include network charges and taxes.

2021, a 1.56% year-on-year increase, while the prices were further increased in the second half of 2021 to 0.1588 €/KWh from 0.1278 €/KWh in the second half of 2020, an increase of 24.25%.

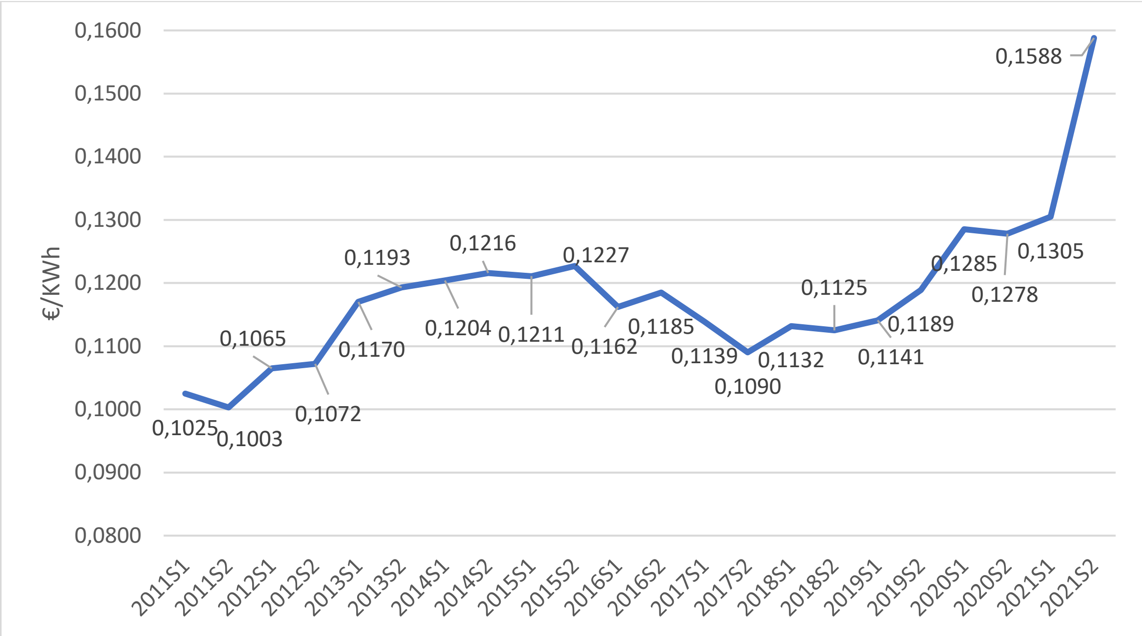


Figure 5: Electricity prices for household consumers – Eurostat (Consumption Band DC: 2,500 kWh < Consumption < 5,000 kWh)

3.2.2.3 Prepayment systems, dynamic price contracts and smart meter use

In Greece the consumers are not equipped with prepayment meters. However, according to the law, suppliers and distribution system operators are allowed to offer prepayment systems in order to invoice end users in advance based on the estimation. If they offer these kinds of systems to household consumers, the system shall adequately reflect likely annual electricity consumption.

Most of the Greek electricity consumers are equipped with standard and time-of-use meters while only a small percentage (less than 5%) of them has smart meters which are part of a pilot program. The smart meter rollout was foreseen to be finished in 2020 but there has been no practical implementation yet. As only a small part of the consumers has smart meters installed, the suppliers do not offer dynamic contracts.

3.2.2.4 Switching rates

The description of the retail electricity market is done separately by Interconnected and Non-Interconnected System, given that the full liberalisation of electricity supply in the Non-Interconnected Islands took place only from January 2018 (RAE Decision 908/2017, law B' 4461) and is therefore not equally mature.

Regarding supplier switching rates, according to HEDNO's data, 7.32% of LV and MV consumers in the Interconnected System switched their supplier in 2021 (8.33% of total consumption in the LV and MV market). The same level of supplier switching is observed at both household consumers and LV-MV commercial and industrial consumers in terms of number of connections. On the other hand, in terms of volume, commercial and industrial consumers showed the greatest switching trend. In general, compared to 2020, the switching trend continued to show for a second consecutive year a stagnation or slight decrease in terms of number of connections while in terms of volume, the switching trend was excessively upward due to the increase of switching rate for all categories of consumers but mainly the LV and MV commercial and industrial consumers.

The following table includes data regarding consumer switching (LV and MV) in the Interconnected system for 2021 (data by HEDNO):

Consumer Category	Number of Consumers in the Interconnected System in 31.12.2021	Number of consumers that switched supplier in 2021	Switching rates (% in number of consumers)	Total Consumption in 2021 (MWh)	Consumption of consumers that switched supplier in 2021 (MWh)	Switching rates (% of consumption volume)
Household consumers (not including Social Tariff)	4,844,787	417,857	8.62%	14,128,640.18	522,221	3.70%
Household Consumers under Social Tariff	499,044	39	0.01%	1,863,242.97	40,321	2.16%
Small industrial and commercial consumers	1,180,473	79,354	6.72%	9,098,982.17	902,495	9.92%
Oher LV consumers	306,164	2,621	0.86%	3,153,472.21	17,070	0.54%
Total LV consumers	**6,830,468**	**499,871**	**7.32%**	**28,244,336**	**1,482,107**	5.25%
Commercial and Industrial consumers	11,057	948	8.57%	8,968,372	1,679,857	18.73%
Oher MV consumers	1,742	26	1.49%	1,570,136	67,937	4.33%
Total MV consumers	12,799	845	6.60%	10,538,508	1,747,794	16.58%
Total number of LV and MV consumers	**6,843,267**	**500,845**	**7.32%**	**38,782,846**	**3,229,901**	8.33%

Table 11: Number of metering points, consumption volume and switching rates per consumer category in the interconnected system's electricity retail market in 2021

Regarding supplier switching in the NNIs, according to HEDNO's data 6.74% of LV and MV consumers switched their supplier in 2021 (8.8% of total consumption in the LV and MV market). The highest percentage of supplier switching is observed at MV (commercial and industrial) consumers in terms of number of meters and consumption volume followed by commercial and industrial consumers at LV and household consumers. The switching rates have remained at the same level in terms of consumption volume compared to 2021 while recording a slight increase in switching rates in terms of both number of meters and consumption volume.

The following table portrays data of consumer switching (LV and MV) in the NIIs in 2021 (data of HEDNO):

Consumer Category	Number of Consumers in the Non-Interconnected System in 31.12.2021	Number of consumers that switched supplier in 2021	Switching rates (% in number of consumers)	Total Consumption in 2021 (MWh)	Consumption of consumers that switched supplier in 2021 (MWh)	Switching rates (% of consumption volume)
Household consumers (not including Social Tariff)	571,924	41,835	7.31%	1,607,718	54,141	3.37%
Household (including Social Tariff)	33,780	1	0.00%	133,546	3,106	2.33%
Small industrial and LV Consumers	155,005	12,095	7.80%	1,503,548	158,367	10.53%
Oher LV consumers	43,089	146	0.34%	417,490	1,607	0.38%
Total LV consumers	803,798	54,077	6.73%	3,662,301	217,220	5.93%
Commercial and Industrial MV consumers	1,022	137	13.41%	958,645	202,998	21.18%
Oher MV consumers	195	4	2.05%	177,357	2,290	1.29%
Total MV consumers	1,217	141	11.59%	1,136,001	205,288	18.07%
Total LV and MV consumers	805,015	54,218	6.74%	4,798,303	422,509	8.81%

Table 12: Number of metering points, consumption volume and switching rates per consumer category in the non-interconnected islands' electricity retail market in 2021

3.2.2.5 Relationship between household and wholesale prices

According to ACER's Annual Report on Monitoring the Internal Energy Retail Markets and Consumer Protection Measures in 2021, there is a strong correlation between the retail and the wholesale electricity price in Greece for 2021. In particular, the calculated mark-up[8] of the Greek electricity suppliers was at negative levels in 2021, however when looking at historical data, Greece was one of the MS that had some of the highest average values over the 2014-2020 period.

[8] According to ACER, the mark-up is an indicator of the theoretical gross 'profitability' of suppliers, as well as an indicator of the level of responsiveness of retail energy prices to changes in prices on wholesale markets. The gross 'profitability' level is the difference between prices charged to consumers and the estimated costs to supply them with energy. This analysis assumes that suppliers are rational and employ a 'close-to-optimal' procurement strategy, as detailed in the methodology and data underlying mark-ups in retail markets. To be clear, mark-ups are not the same as profits, this is because suppliers have additional operating costs (e.g. marketing, sales, consumer services, overhead, etc.) in bringing a product to the market.

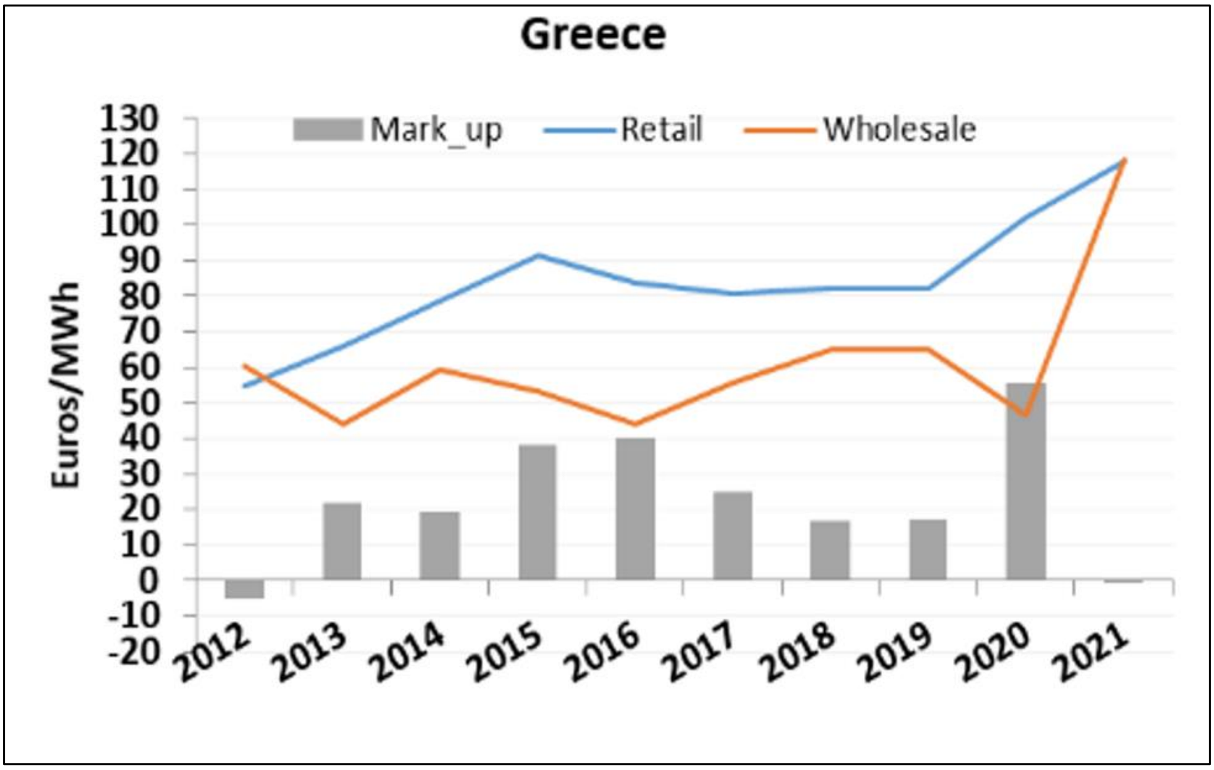


Figure 6: Correlation between wholesale and retail electricity prices – ACER analysis at the Energy Retail and Consumer Protection Volume of the annual MMR

In addition to ACER's analysis, Figure 7 below presents the correlation between the price of the competitive component of the incumbent's tariff, under which most of the LV households are supplied electricity, and the day-ahead market average monthly price. It is clear that starting from July 2021, the increase of the wholesale prices led to the activation of the price adjustment clause[9] of the incumbent's offer and therefore the prices for the consumers were increased. A similar situation was recorded in the offers of other suppliers.

[9] Many electricity offers in Greece consist of both fixed and variable price components. The price adjustment clause is the variable component of the offers that is indexed to wholesale market indicators (monthly day-ahead prices, balancing market prices, electricity losses costs etc). Usually, when the prices exceed certain, pre-defined in the supply contracts, ranges then these price adjustment clauses are activated and the consumers are burdened with the price increases in the wholesale market.

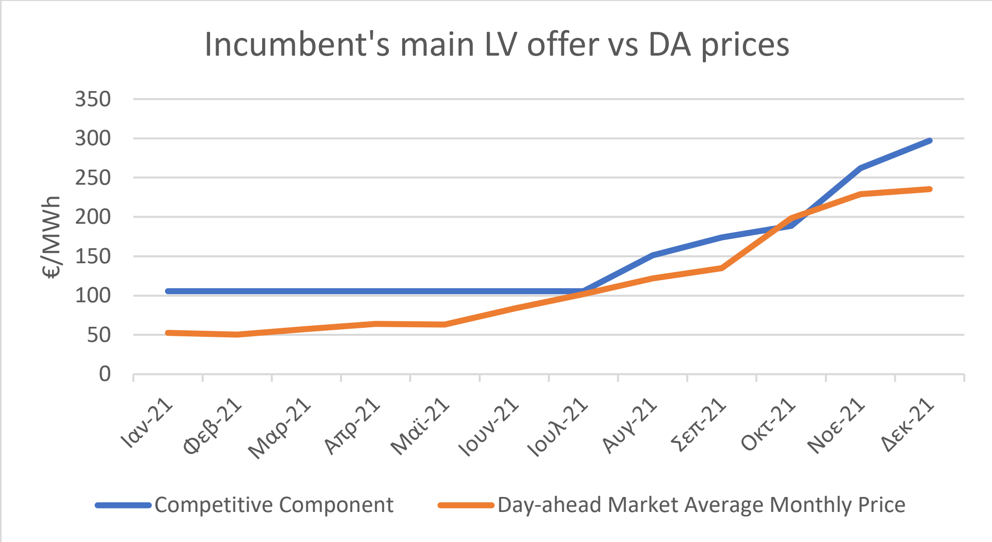


Figure 7: Price correlation between the competitive component of the incumbent's LV household tariff and the day-ahead market average monthly price.

3.2.2.6 Distortion and restriction of competition

During 2021, RAE provided guidelines for the adoption of a common template for electricity contracts and bills to tackle possible distortion and restriction of competition measures by the retail suppliers. These templates, after their approval which is expected within 2022, will empower consumers and strengthen the principles of transparency, comprehensibility and comparability both in the pre-contractual phase and during the execution of the electricity supply contract.

In 2021, RAE initiated systematic monitoring of suppliers, specifically with respect to their adherence to the transparency and accurate information obligations outlined in the Electricity Supply Code. This monitoring focused on situations where suppliers altered their tariff policies, such as switching from a fixed tariff to a variable tariff with the introduction of a price adjustment clause in the consumers' contracts. The Code stipulates a minimum of 60 days' advance notice to the consumer in a clear and legible manner to provide the consumer with the opportunity to exercise their right to switch suppliers. To this end, RAE has diligently and continuously monitored suppliers, issued recommendations, and requested one supplier to attend a written hearing to explain their non-compliance with the aforementioned rules.

3.2.2.7 Other retail market topics

Complaints Tool – myRAE

RAE, in 2021, received a significant number of reports and complaints from electricity and natural gas consumers. For that reason, the Authority proceeded with the creation of an electronic application, which facilitates complaint submission. The tool, which is called myRAE, can be found at https://my.rae.gr/. Requests or complaints are automatically reported to the competent body, in order to be dealt with in a prompt and efficient manner. From its side, RAE is constantly monitoring the progress and the handling of the complaint by these competent bodies and maintains its power to intervene when necessary. Already during the first months of operation of the application within 2021 (September 2021-December 2021), 656 requests/complaints were submitted to it, of which 618 related to electricity.

Bill Templates and Supply Application Form

RAE emphasized on the protection of consumers regarding issues of transparency on energy consumption bills, charges and terms of supply and took measures in order to make the relevant description more comprehensible at the contractual stage. Consumers should be able to verify and compare different contracts in a transparent way. For that reason, RAE, with its Decision 967/2021, gave certain guidelines to electricity Suppliers to adopt a common documents template, such as “Request for LV Electricity Supply Offer” and "LV Consumption Bill".

Amendment of Electricity Supply Code for Consumers

RAE proposed the amendment of the relevant Code in the following fields:

- Non-payment of Consumption Bill

If the bill is not paid within the relevant deadline, the Supplier has the power to proceed with a prominent indication of consumer’s debt to be paid in the next bill. If the debt is not paid within the new deadline, then the Supplier can ask from the DSO to cut off electricity supply. The consumer is notified by his Supplier for the interruption, and he is recorded in the DSO’s information system as delinquent. This recording stops if the consumer pays the whole amount of his own debt or manages to reach a debt settlement with the Supplier. In the case where the consumer does not pay his debt even after the final notification for supply interruption, the Supplier has the power to terminate the contract with the consumer and inform the latter for that action.

- Provide payment settlement to consumers

The Supplier is obliged to provide special programs for the settlement of bills or past debts, especially through installments, and propose at least once the settlement of the debt with a settlement on reasonable terms according to each consumer’s profile. To avoid discrimination between consumers, the Supplier is obliged to set transparent and easily verifiable criteria for the application of the offered settlement programs.

- Supplier switching

A change of Supplier is permitted after prior written termination of supply contract. Contract termination takes place either by the consumer himself or by the new Supplier, following a relevant written authorization by the Consumer. In cases where a meter deactivation order is submitted, the consumer cannot terminate the contract in order to exercise the right to change Supplier, unless he pays in full or settles his overdue debts to the latter. The previous Supplier maintains the right to ask for an interruption of electricity supply, even after the consumer has already been transferred to a new Supplier. More specifically, when the consumer owes the amount of more than 2 bills or if the consumer does not respect the settlement provisions.

3.2.3 Renewable energy sources

3.2.3.1 RES installed capacity and generation and HECHP

The installed capacity of RES units at the end of 2021 amounted to 9,091 MW, showing an increase of approximately 14.57% compared to the one recorded at the end of 2020 (7,935 MW), this significant increase in the country's progress towards achieving national climate and environmental goals is mainly due to the installation of new PV units with a total capacity of 800 MW. Table 13 presents the total capacity distribution per renewable technology. This significant increase was a result of Greece's effort to achieve its mandatory renewable energy goals.

This increase in installed capacity is considered to be particularly significant, as there is a steadily increased investment activity in the RES sector over the past three years and mainly in the field of solar PVs and onshore wind parks. Furthermore, this trend is expected to be strengthened over the next years due to the provision of operating aid to new power plants which were successful in the competitive tender procedures held by RAE since 2018, but also due to the improved economic and investment climate in the country.

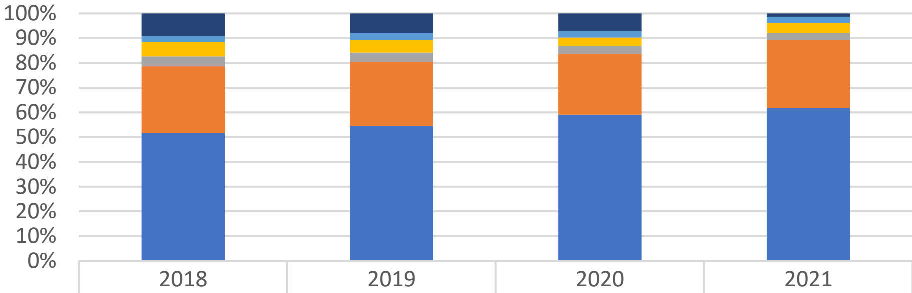
RES Technology	Installed Capacity in 2018 (MW)	Installed Capacity in 2019 (MW)	Installed Capacity in 2020 (MW)	Installed Capacity in 2021 (MW)	% change 2020-2021
Wind	2,860	3,607	4,119	4,456	8.18%
PV	2,269	2,417	2,860	3,660	27.97%
PV on roof (P < 10 kW)	375	375	375	375	0.00%
Hydro Small (P < 15 MW)	240	240	245	251	2.45%
Biomass - Biogas	83	88	97	109	11.90%
Hybrid RES	4	3	3	3	0.00%
HECHP	229	233	235	237	0.66%
Total RES	5,831	6,730	7,699	8,854	15.00%
Total RES, Hybrid RES & HECHP	6,060	6,963	7,935	9,091	14.57%

Table 13: Total RES and HECHP installed capacity and percentage change (2018-2021)

In 2021, RES/CHP production in Greece amounted to 17 TWh in total, which was increased compared to 15.79 TWh in 2020 and represented a share of 34.9% of the total electricity consumption in the interconnected system of Greece.

RES Technology	2018	2019	2020	2021
Biomass	298	367	429	452
Small Hydro (< 15 MW)	718	688	541	679
PV on roofs (< 10 kW)	489	494	494	467
PV	3,304	3,468	3,898	4679
Wind	6,300	7,278	9,323	10503
Total RES*	**11,110**	**12,297**	**14,687**	**16,780**
Hybrid RES	0,37	1.7	3.27	4
HECHP	1,107	1,062	1,102	216
Total RES, Hybrid RES & HECHP	**12,217**	**13,359**	**15,789**	**17,000**
*Excluding large hydroelectric power plants (>15 MW)				

Table 14: Total RES and HECHP generation in GWh (2018-2021)



	2018	2019	2020	2021
CHP	9,96%	8,64%	7,50%	1,29%
Hybrid RES	0,00%	0,01%	0,02%	0,03%
Biomass-Biogas	2,68%	2,98%	2,92%	2,69%
Small hydro	6,46%	5,60%	3,68%	4,05%
PV on roof (<10kW)	4,40%	4,02%	3,36%	2,78%
PV	29,74%	28,21%	26,54%	27,88%
Wind	56,71%	59,19%	63,49%	62,59%

Figure 8: RES and CHP Generation percentage excluding large hydroelectric plants per technology (2018-2021)

3.2.3.2 RES, HECHP and the electricity market

Since 1 November 2019, the RES and HECHP power plants that are compensated under the FiP scheme assume partial balancing responsibilities under the Transitory Mechanism for the Optimal Forecasting Accuracy. With the commencement of operation of the intra-day continuous trading (XBID) under the EU electricity Target Model, the RES and HECHP power plants receiving operating aid under FiP will assume full balancing responsibilities as any other conventional power plant. In addition, RES and HECHP with installed capacity P ≥ 400 kW, that receive operating aid under feed-in-tariff, that have begun their operations after 4 July 2019, assume balancing responsibilities for their load. In addition, balancing responsibilities are borne by the RES aggregators and the aggregator of the last resort (DAPEEP) for the plants they represent in the wholesale electricity markets.

3.2.3.3 RES projects' licensing

Within 2021 RAE issued a total of 4,151 administrative acts and sent 250 letters for supplementary data as part of the evaluation process. The total number of licenses and the number of RAE decisions per category in 2021 is presented in the tables below.

Type of Decision	**Number**
Decisions on Production License granting (accepted)	19
New applications for Production Certificates	2,236
Decisions on application rejection for Production Certificates/Production Licenses	69
Decisions on Production Certificates modification / transfer	1,012
Production Certificates granted due to modification or transfer of the Production License	705
Decisions on Production License extension	25
Administrative acts on Production License infringements	0
Decisions on Production Certificate revocations	19
Decisions on modification requests	66
Total	4,151

Table 15: RAE's licensing activity in 2021

Technology	No of Granted Licenses	Installed Capacity (MW)
Wind	2,039	33,223
PV	2,672	59,221.8
Hydro (small)	555	1,092.8
Geothermal	1	8
Biogas	46	152.6
Biomass	53	234.7
CSP	45	223.3
Hybrid	185	1,186.3
Total	5,596	95,342.5

Table 16: Projects with a license/certificate of generation (operational & non-operational) approved by RAE, December 2021

Revocations / End of duration/ Termination of licenses								
	Wind		Photovoltaics		Hybrid		Total	
	Number of parks	Installed capacity (MW)	Number of parks	Installed capacity (MW)	Number of parks	Installed capacity (MW)	Number of parks	Installed capacity (MW)
Termination of licenses due to failure to keep the relevant project execution deadlines	21	546.85	14	336.20	1	11.50	36	894.6
Voluntary revocations	6	159.45	2	9.38			8	168.8
Projects' revocation in Northern Evia	11	355.40					11	355.4
Termination due to submission of an irrevocable application to return the financial guarantee for the project implementation	1	8.40	6	223.46			7	231.9
Termination due to duration expiry	2	5.45					2	5.5
Total	41	1,075.55	22	569.04	1	11.50	64	1,656.1

Table 17: Revoked RES licenses per technology (2021)

3.2.3.4 RES financial Support Scheme

The current financial support scheme was approved by the European Commission, in November 2016. The main objective of this RES support mechanism is to achieve an efficient integration of renewables' generation into the electricity market. The main change in the RES support financial scheme was the abolition of the Feed-in-Tariff financial support mechanism for new RES projects, and specifically for wind parks larger than 3 MW and other RES projects larger than 0.5 MW, which will now receive operating aid based on the new mechanism of sliding Feed in Premium[10]. Currently, only RES units with installed capacity of 400 kW or less as well as innovative projects can be remunerated under the FiT scheme.

[10] 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)**
1a	Onshore wind parks with installed capacity P_{WIND} > 6 MW	70
1b	Onshore wind parks with installed capacity between 60kW ≤ P_{WIND} ≤ 6MW	89
1c	Wind energy utilized with onshore Wind parks that fall under the scope of the provisions of RAE's decision No. 904/2011, as amended by the decisions of RAE 155/2012 (Gazette B` 908) and 452/2015 (Gazette B` 2859) and is valid, and as defined in the provisions of par. 3 of the article 15 of Law 3175/2003 (A` 207), as well as the holders of park licenses of electricity production from RES that provides to its Experts Conditions that the holder of this license will be included in Table 3 of the new users of the above decisions of RAE.	65
1d	Small Wind parks with installed capacity P_{WIND} ≤ 60kW	157
2	Wind Energy produced by onshore installations with an installed capacity 60kW ≤ P_{WIND} ≤ 6MW, belonging to Energy Communities.	90
3	Small hydropower P ≤ 3MW	90
4	Small hydropower 3MW < P ≤ 15 MW	87
5	Biomass (or bioliquids) from thermal processing P ≤ 1MW (excluding the biodegradable fraction of urban waste)	176
6	Biomass (or bioliquids) through gasification P ≤ 1MW (excluding the biodegradable fraction of urban waste)	185
7	Biomass (or bioliquids) from thermal processing (including gasification) 1MW< P ≤ 5MW (excluding the biodegradable fraction of urban waste)	153
8	Biomass (or bioliquids) from thermal processing (including gasification) P < 5 MW (excluding the biodegradable fraction of urban waste)	133
9	Landfill gas and biogas from anaerobic digestion of the biodegradable fraction of urban waste P ≤ 2MW	123
10	Landfill gas and biogas from anaerobic digestion of the biodegradable fraction of urban waste P > 2MW	99
11α	Biogas released from anaerobic digestion of biomass (energy crops, rural waste and residues, etc.) P ≤ 1MW	219
11β	Biogas released from anaerobic digestion of biomass (energy crops, rural waste and residues, etc.) between 1MW ≤ P ≤ 3MW	209
12	Biogas released from anaerobic digestion of biomass (energy crops, rural waste and residues, etc.) P > 3MW	192
13	Solar thermal without storage system (unless bioliquids are used, in which case see above)	248
14	Solar thermal with storage system (minimum two hours) (unless bioliquids are used, in which case see above)	268
15	Geothermal power P ≤ 5MW	134
16	Geothermal power P > 5MW	104
17	Other renewable energy technologies	88
29a	Solar energy utilized with photovoltaic stations with an installed power ≤ 200kW	63 €/MWh

	Renewable technologies and project categories	RT (€/MWh)
29b	Solar energy utilized with photovoltaic stations with an installed power 200kW ≤ PPV ≤ 500kW	63 €/MWh
30a	Solar energy utilized with photovoltaic stations that belong to energy communities with an installed power PPV ≤ 200kW	65 €/MWh
30c	Solar energy that is utilized by photovoltaic power stations that belong to Energy Communities with installed capacity of ≤1MW or to farmers with installed capacity of <500kW	65
31	Solar energy utilized with photovoltaic stations with installed capacity ≤6kW, connected to a home power supply use and belong to natural persons not tradesmen	87 €/MWh
32[11]	Wind energy utilized with land installations, in Non-Interconnected Islands, installed capacity or maximum power greater than 60 kW and less than or equal to 1 MW consist of wind turbines used in another wind park facility in the past for less than sixteen (16) years.	**1-10 years of operation:** -1.4 x Years of Operation + 70 11 **16 years of operation:** -0.9 x Years of Operation + 61 **Years**: *In whole numbers. In the fall that the number of years is with decimal part, rounded to the next integer unit when it is> 0.5 and in the immediate as the previous whole unit when it is <0.5*
	Solar PV ≥ 0.5MW	Competitive bidding

Table 18: Administrative reference tariffs for RE projects of Law 4414/2016, Table 1 of Article 4.1(b)

[11] New category for used wind turbines for Wind parks in Non-interconnected Islands added in September 2021 based on Ministerial Decision ΥΠΕΝ/ΔΑΠΕΕΚ/78429/3166.

High Efficiency Combined Heat and Power Plants (HECHP) are also applicable for administrative feed-in-tariffs as follows:

	HECHP technologies and project categories	RT (€/MWh)
18	Natural gas HECHP, with a capacity of ≤ 1 MW for categories (a) “Combined cycle gas turbine with heat recovery” or (c) “Steam extraction condensing turbine” referred to in Article 3 of Ministerial Decision Δ5- ΗΛ/Γ/Φ1/οικ.15641/14.07.2009	79 + PR
19	HECHP with the use of natural gas, with a capacity of ≤ 1MW for other categories referred to in Article 3 of Ministerial Decision Δ5- ΗΛ/Γ/Φ1/οικ.15641/14.07.2009	84 + PR
20	HECHP with the use of natural gas with a capacity of > 1 MW and ≤ 5 MW for categories (a) ‘Combined cycle gas turbine with heat recovery’ or (c) ‘Steam extraction condensing turbine’ referred to in Article 3 of Ministerial Decision Δ5-ΗΛ/Γ/Φ1/οικ.15641/14.07.2009)	73 + PR
21	HECHP with the use of natural gas, with a capacity of > 1 MW and ≤ 5 MW of other categories referred to in Article 3 of Ministerial Decision Δ5- ΗΛ/Γ/Φ1/οικ.15641/14.07.2009	78 + PR
22	HECHP with the use of natural gas, with a capacity of > 5 MW and ≤ 10 MW for categories (a) “Combined cycle gas turbine with heat recovery” or (c) “Steam extraction condensing turbine” referred to in Article 3 of Ministerial Decision Δ5- ΗΛ/Γ/Φ1/οικ. 15641/14.07.2009	69 + PR
23	HECHP with the use of natural gas, with a capacity of > 5 MW and ≤ 10 MW for other categories referred to in Article 3 of Ministerial Decision Δ5- ΗΛ/Γ/Φ1/οικ.15641/14.07.2009	73 + PR
24	HECHP with the use of natural gas, with a capacity of > 10 MW and ≤ 35 MW for categories (a) ‘Combined cycle gas turbine with heat recovery’ or (c) ‘Steam extraction condensing turbine’ referred to in Article 3 of Ministerial Decision Δ5-ΗΛ/Γ/Φ1/οικ.15641/14.07.2009	63 + PR
25	HECHP with the use of natural gas, with a capacity of >10 MW and ≤ 35 MW for other categories referred to in Article 3 of Ministerial Decision Δ5- ΗΛ/Γ/Φ1/οικ.15641/14.07.2009	68 + PR
26	HECHP with the use of natural gas, with capacity of > 35 MW for categories (a) “Combined cycle gas turbine with heat recovery” or (c) “Steam extraction condensing turbine” referred to in Article 3 of Ministerial Decision Δ5- ΗΛ/Γ/Φ1/οικ. 15641/14.07.2009	58 + PR
27	HECHP with the use of natural gas, with a capacity of > 35 MW of other categories stipulated in Article 3 of Ministerial Decision Δ5- ΗΛ/Γ/Φ1/οικ.15641/14.07.2009	62 + PR
28	Other HECHP	83
33	HECHP using biofluids (produced from raw materials other than those listed in Annex IX to Directive (EU) 2018/2001) power up to 1 MW with utilization of the generated energy for agricultural purposes *. ** For total cumulative installed capacity of category projects 33 and 34 to 10 MW stations*	203 * * the supplement has already been included 15% of the case e) of par. 1 of article 4 of law 4414/2016 (Government Gazette A’149)
34	HECHP using biofluids (produced from raw materials other than those listed in Annex IX to Directive (EU) 2018/2001) power up to 1 MW with utilization of the generated energy and exhaust gases for agricultural purposes *. ** For total cumulative installed capacity of category projects 33 and 34 to 10 MW stations*	206 * * the supplements of 15% and 20% of the case- e) of par. 1 of article 4 of Law 4414/2016 (Government Gazette A’149)
35	HECHP using Natural Gas> 35 MW for categories (a) "Combined gas turbine cycle with heat recovery" or (c) "Condensing - extraction steam turbine" of Article 3 of ΥΑ Δ5-ΗΛ / Γ / Φ1 / οικ.15641 / 14.07.2009 and provision of the produced thermal energy exclusively for heating cities through District heating network	84 + PR * * the supplement has already been included 15% of the case par. 1 of article 4 of law 4414/2016 (Government Gazette A’149)
36	HECHP using Natural Gas> 35 MW of other categories of article 3 of ΥΑ Δ5-ΗΛ / Γ / Φ1 / οικ.15641 / 14.07.2009 and provision of the thermal energy produced exclusively for heating cities via District Heating network	80 + PR * * the supplement has already been included 15% of the case par. 1 of article 4 of law

		4414/2016 (Government Gazette A'149)
Relevant legal framework setting the administrative tariffs: Ministerial Decisions ΥΠΕΝ/ΔΑΠΕΕΚ/30971/1190 & ΥΠΕΝ/ΔΑΠΕΕΚ/78429/3166.		

Table 19: Administrative reference tariffs for HECHP projects of Law 4414/2016, Table 1 of Article 4.1(b)

$$PR = (AVNG_t-26) \times [(1-(n-n_e)/n_{hr}))/n_e]$$

Where:

η_e**:** Power efficiency of cogeneration unit, as specified in Ministerial Decision Δ5-ΗΛ/Γ/Φ1/749/ 21.3.2012 (Gazette B', 889/2012)

η_{th}**:** Thermal efficiency of cogeneration unit, as specified in Ministerial Decision Δ5-ΗΛ/Γ/Φ1/749/21.3.2012 (Gazette B', No 889/2012)

$AVNG_t$: The average monthly gross unit price of natural gas in €/MWh of Gross Calorific Value which includes the selling price that takes into account the transportation cost, the special consumption tax and the average CO2 cost corresponding to electricity production and any additional taxes or charges, excluding VAT.

$\eta = \eta_e + \eta_{th}$**:** Total efficiency of cogeneration unit

η_{hr}**:** the reference value of efficiency for the separate generation of thermal energy, as specified in Ministerial Decision Δ5-ΗΛ/Γ/Φ1/749/21.3.2012 (Gazette B', No 889); where efficiency rates, expressed in maximum calorific value (MCV) are set out in Table 2, paragraph 1(d).

If in a power generation station from HECHP of Table 1 case b, the thermal energy produced is either used for the production of agricultural products, provided the production of agricultural products is the main activity of the producer, or is available through a city district heating network, the fixed part of the price of the above Table 1 (price excluding VAT) is increased by 15%. If at a HECHP station of Table 1 case b, the exhaust gases are used for agricultural purposes, the fixed part of the price of the table (price excluding VAT) is increased by 20% and this increase is calculated in addition to any increase according to the provisions of the previous paragraph.

The Reference Tariff (RT), is used to calculate Operating Aid on a monthly basis. The aid takes the shape of either a Sliding Feed-in Premium (sFiP) or a fixed price. It applies specifically to the electricity produced from Renewable Energy Sources (RES) or High-Efficiency Combined Heat and Power (HECHP). The determination of this RT depends on the technology utilized in the production process, as outlined in Tables 18 and 19.

In essence, this scheme is designed to support revenue based on cost reflective, market-based Operating Aid, which ensures that both phenomena of *over-compensation* and *under-compensation* of power production from RES and HECHP are minimized. A technology-specific sFiP is 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 RT per renewable energy technology. The RTs initially are administratively determined for all technologies, and from 2017 would be set through competitive bidding for most producers, on a project-by-project basis.

As from 1 January 2016, all RES and HECHP power parks 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 4414/2016.

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 DAPEEP, for the power generated from RES and HECHP parks 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 a 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 parks) and *non-intermittent* (i.e. biomass, biogas, geothermal, solar thermal including storage facilities, and highly efficient co-generation of heat and power parks) renewable energy projects. The type and contents of the FiPC, as well as the conclusion procedure, was set out in a Ministerial Decision based on a proposal of DAPEEP and the opinion of the RAE. 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 innovative, transparent, simplified, valid and reliable, and regarded as best practice by many European stakeholders. The innovative electronic auction procedure is based on a Yankee Reverse auction type, and is conducted in two phases: (1) online submission of the applications' supporting documents, and (2) conduction of the auctions on the same custom made platform for all the relevant categories of projects.

Based on RAE Opinion 9/2021 the Ministerial decision ΥΠΕΝ/ΔΑΠΕΕΚ/123726/5096 (Gazette B '6250/27.12.2021) was issued. The Decision set the maximum auctioned capacity per RES and HECHP technology, the minimum number of RES competitive procedures per year, the maximum bidding prices per auction, and the relevant fees for the participation in the auctions until 2025.

More specifically, it was determined therein that within 2022 the following RES technologies will participate in RES auctions: a) Wind parks with a maximum capacity of more than 6 MW; b) Wind parks with a maximum capacity greater than 60 kW and less than or equal to 6 MW that do not meet the criterion of article 7 (3a) of Law 4414/2016 (A΄ 149); c) Photovoltaic power parks with an installed capacity of more than 1 MW; d) Photovoltaic power parks with an installed capacity 500kW ≤ P_{pv} ≤ 1MW that do not belong to Energy Communities; e) Photovoltaic power parks with an installed capacity of less than 500 kW that do not belong to Energy Communities and that do not meet the conditions for exemption from competitive procedures of Article 7 (3) of Law 4414/ 2016 (A' 149), as well as Photovoltaic power parks with an installed capacity of less than or equal to 1 MW that belong to Energy Communities and do not meet the conditions for exemption from competitive procedures of 7 (3) of Law 4414/2016 (A΄ 149); 4 f) Wind power parks with a maximum output of more than 10 MW with built-in electricity storage capacity of at least 20% of the maximum hourly energy produced; g) Photovoltaic power parks with an installed capacity of more than 10 MW with built-in electricity storage capacity of at least 20% of the maximum hourly energy produced. Photovoltaic power parks with an installed capacity 500kW ≤ P_{pv} ≤ 1MW that belong to Energy Communities as well as photovoltaic parks with an installed capacity of less than 500 kW that do not belong to Energy Communities, who meet the conditions for exemption from the competitive procedures of Article 7 (3) of Law 4414/2016 (A' 149), may participate in competitive tenders in the same category as the power parks of the category e). Wind power parks with an installed capacity 60kW ≤ P_{WIND} ≤ 6MW that meet the criterion article 7 (3) of Law 4414/2016 (A΄ 149), may participate in competitive tendering procedures involving category b) wind farms.

Furthermore, with the same Ministerial Decision, it was decided that within the period 2022-2025 the following RES technologies will participate in competitive procedures: a) Wind parks with an installed capacity 60kW ≤ P_{WIND} ≤ 6MW; b) Wind parks with an installed capacity of more than 6 MW; c)

Photovoltaic power parks with an installed capacity of less than or equal to 1 MW; d) Photovoltaic power parks with an installed capacity of more than 1 MW; e) Wind parks with an installed capacity of more than 10 MW with storage capacity of at least 20% of the maximum hourly energy produced; f) Photovoltaic power parks with an installed capacity of more than 10 MW with a electricity storage capacity of at least 20% of the maximum hourly energy produced.

3.2.3.5 Competitive auctions for RE projects

In 2021, one (1) RES auction was held in Greece, the results of which are summarized in Table 20:

<table>
<tr><th colspan="14">1st Cycle Auction, Technology Neutral – Common Competitive Auction, May 2021 - Results</th></tr>
<tr><th rowspan="2">Categories</th><th rowspan="2">Auctioned Capacity (max) (MW)</th><th rowspan="2">Final Auctioned Capacity (MW)</th><th colspan="6">Project Applications (No/MW)</th><th colspan="5">Auction</th></tr>
<tr><th colspan="2">Applied</th><th colspan="2">Approved</th><th colspan="2">Granted</th><th>Bids</th><th>Ceiling price (€/MWh)</th><th>Highest Bid (/€MWh)</th><th>Lowest Bid (€/MWh)</th><th>Weighted average price (€/MWh)</th></tr>
<tr><td>PV parks with $P_{pv} \leq$ 20 MW & Wind parks with $P_{wind} \leq$ 50 MW</td><td>350</td><td>350</td><td>128</td><td>1,114</td><td>124</td><td>1,088</td><td>49</td><td>349.91</td><td>2,188</td><td>53.86</td><td>51.2</td><td>32.97</td><td>37.6</td></tr>
</table>

Table 20: Detailed results for the single technology-neutral RES auction held in 2021

3.2.3.6 RES financing

Several instruments have been in place to support the financing of RES, including: (a) a revenue from the operation of the day ahead and intraday markets, (b) a revenue from the imbalances settlement procedures of the balancing market, (c) a revenue from the RES power plants that participate in the electricity wholesale market through the Aggregator of the Last Resort (d) a revenue from the Temporary Mechanism of Optimal Forecast Accuracy, (e) a revenue from the "RES Levy" paid by the consumers and (f) a revenue for CO_2 emission rights. Starting from 1 January 2021 the revenue equal to the average variable cost of conventional Generation units was abolished.

Ministerial Decision ΥΠΕΝ/ΓΔΕ/76979/4917 (Gazette 3373 / B / 31-8-2019) sets forth the appropriate regulatory framework in order to put into effect the new scheme of reduced charges of RES Levy ("ETMEAR in Greek") from 1 January 2019, as required by the European Commission Communication on State Aid Guidelines for the Environment and Energy 2014 to 2020 (EEAG) (Official Journal of the European Union, 2014 / C200 / 01). DAPEEP S.A. is defined as the responsible body for the implementation and operation of the information system for the RES Levy. The details of transaction management procedures of RES Levy from 1.4.2019 are determined in the DAPEEP Code. In addition, in accordance with the provisions set in article 143 of Law 4001/2011, RAE determines the RES Levy's unit charges imposed on consumers of each category. These responsibilities were taken away from RAE and assumed by the Ministry for Energy for the years 2019 and 2020, while in 2021, RAE continued to set again those unit charges. RAE, taking into account the relevant data received by DAPEEP S.A., the body responsible for the management of the RES financing account, with its Decision 1063/2021 (Gazette B' 6419) maintained the RES Levy unit charge at 17 €/MWh for 2022. The RES unit charges are available in the table below:[12]

[12] All consumer categories except those that use electricity for agriculture must pay the full base charge of 17€/MWh for the first 250 MWh consumed annually.

Consumers Classification	Unit Charges (€/MWh)
Households (LV)	17.00 €
Other uses (LV)	17.00 €
Other consumers	17.00 €
Business organizations with activities in a sector which is included in Annex 3 of the EEAG, with electro-intensity < 10%	2.55 €
Business organizations with activities in a sector which is included in Annex 3 of the EEAG, with electro-intensity ≥ 10% and electro-intensity < 20%	2.55 €
Business organizations with activities in a sector which is included in Annex 3 of the EEAG, with electro-intensity ≥ 20%	2.55 €
Business organizations with activities in a sector which is included in Annex 5 of the EEAG, with electro-intensity ≥ 20%	2.55 €
Business organizations with activities in a sector which is included in Annex 5 of the EEAG, with electro-intensity ≥ 10% and electro-intensity < 20%	3.40 €
Business organizations with activities in a sector which is NOT included in Annexes 3 & 5 of the EEAG, with electro-intensity ≥ 20%	3.40 €
Lignite mines and pumping stations with HV connections and rail transit with MV or HV connections	3.40 €
Agricultural use of electricity (LV or MV)	9.01 €
i) Business organisations with activities in sea travel; Business organisations; ii) Business organisations with activities in air travel; iii) Business organisations with activities related to hotels and similar accommodations; iv) Business organisations with activities related to holiday accommodation and other short-stay accommodation; v) Businesses with activities related to campsites, facilities for recreational and trailer towed vehicles	9.01 €

Table 21: New RES Levy (ETMEAR) Unit Charges (2021)

At the end of 2021, the RES financing account recorded a surplus of € 322.86 million, mainly due to the increased wholesale electricity prices recorded after August 2021 as a result of the global energy crisis. It should be noted that the deficit of € -263.76 million, which was recorded at the end of 2020 continued to increase, regardless of the measures introduced by the package of financial and structural measures of Law 4759/2020 (Gazette A' 245), until June 2021 when it was amounted to € -510.01 million (see Figure 9). The main components of the RES special account are presented in Table 22 below.

		2020	2021
Aggregator of the last resort account	DAM and IDM revenues for units represented by the aggregator of the last resort	12.500	10.129
	Settlement of units represented by the aggregator of the last resort	-10.918	-12.039
	Aggregator of the last resort account balance	**1.583**	**-1.910**
Subaccount for the electricity market (ΛΓ1)	DAM and IDM revenues for units operating under PPAs, FiTs and the terms of the Special PV rooftop programme	463.253	1,265.97
	Imbalance settlement of units operating under PPAs, FiTs and the terms of the Special PV rooftop programme	-5.525	-49.40
	Imbalance settlement of units that are either represented by an aggregator or participate directly in the electricity market	-5.600	-26.36
	Imbalance settlement of units represented by the aggregator of the last resort	-1.943	1.49
	Imbalance settlement of RES units located in Crete	Not applicable	0.98
	Additional settlement of Crete's electricity suppliers	Not applicable	0.88
	Temporary Mechanism of Optimal Forecast Accuracy (TMOFA)	0.075	0.29
	Variable cost of conventional Generation units (VCCGU)	150.012	Not applicable
	Disincentive for units represented by the aggregator of the last resort	0.132	0.57
	Imbalance cost	0.142	1.07
	Total revenues	**600.546**	**1.195.49**
	Aggregator of the last resort account balance	1.583	-1.91
	Subaccount for the electricity market (ΛΓ1) balance	**547.528**	**1,193.58**
Subaccount for RES support (ΛΓ2)	RES levy (ETMEAP)	551.284	568.26
	CO_2 emission rights	409.703	40.59
	Special contribution by the suppliers of the interconnected system[13]	Not applicable	93.60
	Special contribution by the RES units of the interconnected system[13]	Not applicable	83.49
	Special contribution of the rooftop PV owners[13]	Not applicable	11.53
	Total revenues	975.450	797.46
	Remuneration of units operating under FiPs	-149.139	137.97
	"Readiness" Support payments (RSP)	-0.981	-0.61
	10-day settlement	Not applicable	-1.486
	Total expenses	**-150.120**	**135.87**
	Non-interconnected islands' account balance	64.869	91.44
	Subaccount for RES support (ΛΓ2) balance	935.368	1,024.78
Main RES financing account	Subaccount for the electricity market (ΛΓ1) balance	547.53	1,193.58
	Subaccount for RES support (ΛΓ2) balance	935.37	1,024.78
	Total revenues	1,482.90	2,218.36
	Remuneration of units operating under PPAs & FiTs	-1,645.94	-1,625.12
	Remuneration of roof PV units	-193.92	-185.18
	Total expenses	-1,839.85	-1,810.31
	Main RES financing account balance	-356.96	408.05
	Main RES financing aggregated account	**-263.76**	**144.20**
Revenues from the special fee for the issuance of Electricity Production Certificates		Not applicable	55.17
Revenues from the "Green levy" of on diesel fuel		Not applicable	108.38
Other revenues		Not applicable	15.11
Main RES financing aggregated account including revenues from special measures		**-263.76**	**322.86**

Table 22: RES' Financing Account statistics in million EUR (2020-2021)

[13] Introduced by Law 4759/2020 (Gazette A' 245) as a package of financial and structural measures to address the existing deficit recorded in 2020.

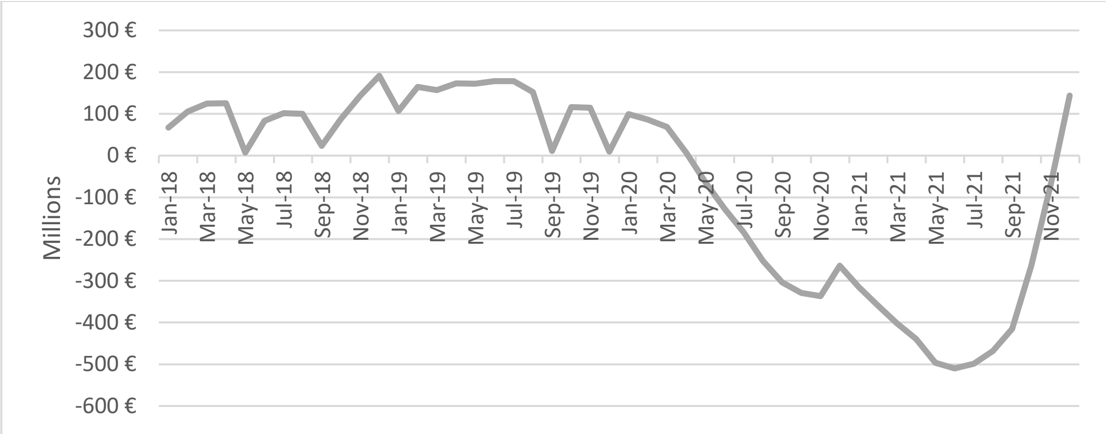


Figure 9: RES Financing Account's Progress (2018-2021)

3.2.3.7 New RES Legislation and Regulatory Development

Primary legislation

On July 23, 2021, Law 4819/2021 was enacted (Gazette A' 129). Articles 128 to 147 of this Law introduced the mandatory submission of financial guarantees for applicants for Electricity Production Certificates and Electricity Production Certificates for Special RES and HECHP power plants. A financial guarantee of 35,000 €/MW of power plant's installed capacity must be provided within five days after the submission of application. This amount may be covered by more than one financial guarantee. In addition, it is stipulated that in the event of an increase in the installed capacity, as it is provided in the Certificate or in the Certificate of Special Power Projects or in the production license, the applicant must increase the total sum covered by financial guarantee(s).

In addition, in the context of the above article, on the one hand, issues related to the return of the financial guarantee of Production Certificates are regulated. The return of the guarantee takes place by submitting a complete dossier application to the competent network operator to receive the final connection terms of the power plant to the network. In addition, the financial guarantee may be refunded between the time of application submission and the issuance of the Production Certificate, in which case the application for Production Certificate issuance is declined by RAE.

Finally, the above article also defines the exemptions from the obligation to submit a financial guarantee, for specific categories of power plants, such as a) plants with a installed capacity of less than or equal to 1 MW, b) plants that are included in the strategic investments of Law 4608/2019 before the entry into force of the law, and c) the power plants developed by local authorities, institutions as well as public entities. and legal entities governed by private law, such as hospitals, health centers and schools of all levels. Finally, the mandatory submission of the financial guarantee by 28.02.2022 is foreseen for the holders of existing production licenses and Production certificates, who have not submitted an application to be granted final connection terms to the competent network operator. In any other case, their production licenses or certificates will be revoked.

The first applications under the above measure were submitted in the October's 2021 Cycle. In particular. 127 applications were submitted, for RES power plants with a total installed capacity amounting to 960 MW. The number of the applications was significantly reduced compared to the previous June cycle of 2021 (743 applications for power with a total capacity of 17.45 GW).

3.2.4 Non-interconnected islands

“Non-Interconnected Islands” (NIIs) are the Greek islands whose electricity distribution system is not connected to the transmission system or the distribution system of the mainland. HEDNO S.A. is the responsible company for the operation of the autonomous electrical systems of the Non-Interconnected Islands. Its responsibility includes the operation of the production, the functioning of the market and of the systems of these islands and is conducted in accordance with the “Operation Code of Electricity Systems of Non-Interconnected Islands”, issued pursuant to article 130 of Law 4001/2011.

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[14].

With the completion of Phases B and C of Cyclades interconnection, their systems’ reliability and stability are now further secured. However, a significant number of NIIs continue still to be electrified by the local production units of PPC S.A., which are fuelled with oil, either heavy (fuel oil) and/or light (diesel). The contribution of RES is also important, especially the wind and photovoltaic parks, which operate on these islands.

The Non-Interconnected Islands (NIIs) market consists of twenty-nine (29) autonomous systems. Some of them consist of several islands (island clusters).

The size of the twenty-nine (29) autonomous island electrical systems of the country varies. Nineteen (19) “small” autonomous systems with a peak demand up to 10 MW. Eight (8) “medium-size” autonomous systems with a peak demand from 10 to 100 MW. Two (2) “large” autonomous systems with a peak demand of more than 100 MW (Crete and Rhodes). The annual demand for electricity in the NIIs varies in size, from a few hundred MWh on the smaller islands (Antikythira, Agathonisi, etc.), to some TWh in the larger NII (Crete).

3.2.4.1 Electricity Supply Structure

In Non – Interconnected Islands, the 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 consumers’ loads. The dispatching of the units is done to achieve the lowest cost, maximizing at the same time the contribution of RES production while also considering the security of supply.

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

[14] 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.

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 parks to provide continuous 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.

In 2021, the company “Petrogaz S.A.” withdrew from the supply of electricity in the NII. By the end of the year, 16 suppliers (excluding the five (5) Universal Service Providers and the Supplier of Last Resort were active in the Non-Interconnected Islands:[15]

	Supplier Name:
1.	PPC
2.	ELINOIL
3.	ELTA
4.	ELPEDISON
5.	ZENITH
6.	HERON
7.	KEN
8.	PROTERGIA
9.	NRG
10.	OTE ESTATE
11.	PETROGAZ*
12.	NATURAL GAS
13.	VOLTERRA
14.	VOLTON
15.	WATT & VOLT
16.	WE ENERGY
17.	UNIVERSAL SERVICE PROVIDER (PPC S.A.)
18.	UNIVERSAL SERVICE PROVIDER (MYTILINEOS S.A.)
19.	UNIVERSAL SERVICE PROVIDER (ELPEDISON S.A.)
20.	UNIVERSAL SERVICE PROVIDER (HERON S.A.)
21.	UNIVERSAL SERVICE PROVIDER (NRG S.A.)
22.	SUPPLIER OF LAST RESORT (ELPEDISON S.A.)
*The supplier ceased its activity within 2021	

Table 23: Companies active in the electricity supply market of Non-Interconnected Islands (2021)

PPC remained the dominant Supplier in the retail electricity market and in the networks of the Non-Interconnected Islands, representing 78.72% of the total number of connections in the LV and MV networks and 64.25% of the total consumption, although there was a decline in its market share. Figure 10 and Figure 11 present the market shares in supplied electricity volume (LV and MV) and connections respectively, in the non-interconnected system according to HEDNO S.A. data for 2021.

[15] As of 01.01.2018 and according to RAE Decision No. 908/2017 (Gazette 4461 B '/ 19.12.2017), the full liberalization of electricity supply in the Non-Interconnected Islands was enacted.

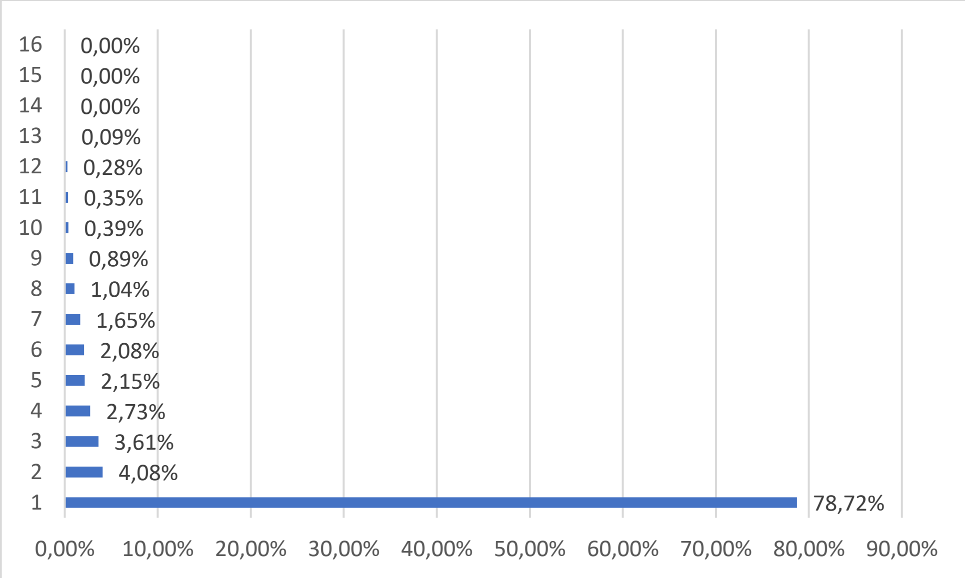


Figure 10: Market shares in Retail Electricity Market based on based on number of connections (LV and MV) in the Non-Interconnected System (2021)

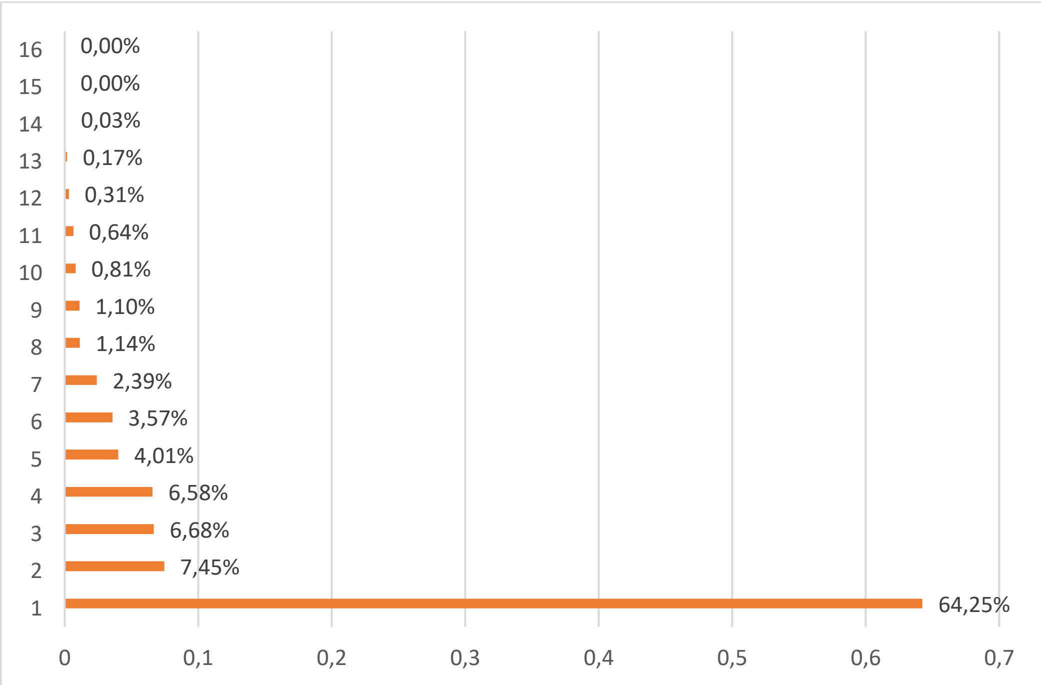


Figure 11: Market shares in Retail Electricity Market based on based on consumption volumes (LV and MV) in the Non-Interconnected System (2021)

The Herfindahl-Hirschman Index (HHI) is estimated at 4,283 for 2021 in the Non-Interconnected Islands regarding consumption volume, significantly exceeding the threshold of 2,000 (high market concentration threshold), and higher than the corresponding index in the Interconnected System.

3.2.4.2 Electricity Generation Capacity and Electricity Demand

The share of RES’ generation in the total electricity generation of the 29-autonomous power system was 8.22% in 2021. In Crete, the largest island of the non-interconnected system, the share of RES in total generation was 22.65%. The level of demand of the 29 autonomous non-interconnected islands varies significantly:

- 19 out of 29 have a peak demand level less than 10 MW.
- 7 out of 29 have a peak demand level from 10 MW up to 100 MW.
- And only 3 autonomous non-interconnected islands have a peak demand level over 100 MW (Crete, Kos & Rhodes).

The annual electricity demand among the autonomous non-interconnected systems varies too, from few hundreds of MWh up to few TWh (see Table 25).

	Non-interconnected autonomous power systems (islands)	Electricity Production from RES Power Plants (MWh)	Electricity Production from Conventional Plants (MWh)	% Production from RES	Demand (MWh)	Peak demand (MW)
1	St Eustratios	0.00	1,152.69	0.00%	1,152.69	0.35
2	Agathonisi	0.00	887.65	0.00%	887.65	0.24
3	Amorgos	467.51	11,117.46	4.04%	11,584.97	3.5
4	Anafi	0.00	1,402.16	0.00%	1,402.16	0.64
5	Antikythera	0.00	330.92	0.00%	330.92	0.10
6	Arkie	0.00	417.46	0.00%	417.46	0.16
7	Astepalaia	567.85	6,756.22	7.75%	7,324.07	2.59
8	Gavdos	0.00	589.54	0.00%	589.54	0.18
9	Donoussa	0.22	1,134.25	0.02%	1,134.47	0.46
10	Erikoussa	0.00	873.39	0.00%	873.39	0.53
11	Thira	981.79	196,181.28	0.50%	197,163.07	58.35
12	Ikaria	7,893.81	22,268.00	26.17%	30,161.81	9.60
13	Karpathos	6,334.18	32,504.59	16.31%	38,838.77	12.45
14	Crete	605,451.17	2,067,126.90	22.65%	2,672,578.07	605,10*
15	Kythnos	393.25	11,397.37	3.34%	11,790.62	4.34
16	Kos-Kalymnos	57,996.08	304,698.39	15.99%	362,694.47	106.08
17	Lesbos	50,874.93	237,726.63	17.63%	288,601.56	68.36
18	Lemnos	9,018.68	51,910.81	14.80%	60,929.49	16.30
19	Megisti	0.00	3,825.34	0.00%	3,825.34	1.19
20	Melos	7,528.72	46,131.81	14.03%	53,660.53	14.52
21	Othonei	0.00	667.44	0.00%	667.44	0.29
22	Patmos	3,196.86	16,475.55	16.25%	19,672.41	6.14
23	Rhodes	131,532.99	644,440.53	16.95%	775,973.52	237.47
24	Samos	30,858.10	100,770.95	23.44%	131,629.05	33.10
25	Serifos	212.53	9,844.85	2.11%	10,057.38	4.14
26	Sifnos	3,148.02	18,033.51	14.86%	21,181.53	7.50
27	Skeros	504.22	15,696.99	3.11%	16,201.21	4.86
28	Semi	242.62	13,888.77	1.72%	14,131.39	4.06
29	Chios	34,526.83	171,611.89	16.75%	206,138.72	51.90
	TOTAL	3,989,863.33	951,730.37	8.22% (Average)	4,941,593.71	NAP
	*Refers to the peak demand of 2020 as Crete is no longer considered a NNI from November 2021					

Table 24: Electricity Generation in Non-Interconnected Islands (NII) for 2021

Non-interconnected islands	2017	2018	2019	2020	2021
St Eustrations	1,095	1,124	1,123	1,104	1,153
Agathonisi	727	718	765	828	888
Amorgos	10,710	11,188	11,282	9,806	11,585
Anafe	1,298	1,371	1,358	1,208	1,402
Antikythera	276	274	300	399	331
Astepalaia	7,008	7,064	7,268	6,736	7,324
Donoussa	1,016	1,118	1,125	954	1,134
Hereikousa	879	895	820	817	873
Thera	181,674	199,744	217,105	146,459	197,163
Ikaria	28,047	27,878	28,528	27,227	30,162
Karpathos	37,319	38,455	39,805	32,093	38,839
Kythnos	9,586	9,578	10,000	10,059	11,791
Kos-Kalemnos	382,075	392,964	405,385	315,078	362,694
Lesvos	299,860	299,177	299,923	289,962	288,602
Lemnos	60,411	60,378	60,724	58,560	60,929
Megisti	3,549	3,762	3,866	3,582	3,825
Melos	49,181	50,573	52,479	46,946	53,661
Othonoi	645	640	629	578	667
Patmos	18,438	18,894	19,570	17,755	19,672
Samos	140,447	140,252	140,629	126,821	131,629
Serifos	8,680	8,701	9,183	8,540	10,057
Sifnos	18,633	19,069	19,344	17,449	21,182
Skeros	16,266	15,666	16,126	15,329	16,201
Semei	14,285	14,673	14,900	12,205	14,131
Chios	210,435	204,987	206,908	200,921	206,139
Rhodos	836,397	864,624	867,271	637,567	775,974
Crete	3,027,253	3,055,605	3,083,427	2,785,712	2,672,578
Note: Most of the 29 autonomous power systems include more than one island (micro islands)					

Table 25: Historical Annual Electricity Consumption in NII, 2017 – 2021 (MWh)

3.2.4.3 Other regulatory developments in NIIs

Approval of annual PSO compensation charge

The market of the Non-Interconnected Islands (NII) remains a regulated activity, as previously detailed in RAE's reports, and it does not allow Generators and Load Representatives to participate in the Electricity Target Model Markets under Law 4425/2016. Settlement of the NII market is conducted on an accounting basis, contingent upon RAE's approval of the operation and production costs of thermal power plants. Producers are compensated for the full production cost, while suppliers are compensated for the excess cost of electricity production on these islands through the Public Service Obligation Compensation (PSOC).

In the context of approving the annual compensation for the year 2018, as per the methodology established by RAE in Decision 14/2014 (Gazette B΄ 270/07.02.2014), the Authority conducted a comprehensive audit of the expenses submitted by HEDNO S.A., the Operator of the NIIs for electricity production from the Conventional Power Plants of PPC S.A. Particular attention was given to data related to the Depreciated Value and depreciation of fixed assets in PPC S.A.'s generation activity in the Non-Interconnected Islands, which are part of the Regulatory Asset Register (RAR) for thermal generators.

The 2018 RAR submitted by PPC for RAE's approval was thoroughly evaluated to ensure compliance with the rules for recording and maintaining fixed assets as defined by the Authority in relevant regulatory framework. It was also assessed for the accurate calculation of the Written-Down Value and depreciation of fixed assets, excluding the generator's fixed assets in the three (3) Non-Interconnected Islands' electricity systems interconnected in 2018 (from the date of their connection to the mainland system). To control related costs and minimize the risk of overcharging consumers, the Depreciated Value of fixed assets under the RAR excludes revaluation of fixed assets in the year 2009 and any subsequent revaluations, as well as investment subsidies.

RAE approved the Regulatory Asset Register for electricity generation from Conventional Power Plants in the NII for 2018 through Decision 951/2021. The Written Down Value was €874 million, and Depreciation was €45.284 million.

4 THE GAS MARKET

4.1 Network regulation and technical functioning

In the field of network regulation, RAE has as its main responsibility to ensure the realization of the necessary network investments, the security of the natural gas supply and the protection of consumers, especially in relation to the transparency in the process of setting the Required Revenue and the network tariffs paid by the network consumers.

The determination of the network tariffs, paid annually by the natural gas consumers to use the Transmission System and the Distribution network is based on three basic steps:

- The development of a detailed methodology (Tariff Regulation) to estimate the reasonable revenue for each year of the Regulatory Period. The calculation of the revenue is made before the start of the Regulatory Period (4-year period), taking into account the estimated annual operating expenses, the depreciation on the fixed assets, as well as the return on the Regulated Asset Base (RAB). Necessary adjustments are made in relation to the initially approved revenue parameters within the Regulatory Period to calculate the Recoverable Difference, in accordance with the provisions of the Tariff Regulation for each regulated activity.
- The socialization of the network costs and their allocation to the network users in a fair and reasonable manner.
- The Required Revenue and the network tariffs are approved by RAE based on reports developed by the network operators according to article 88 of Law 4001/2011.

Network Development Plans

RAE Decision 116/2021 approved the Network Development Plan (NDP) of the National Natural Gas System (NNGS) for the period 2021-2030. The network operator of the NNGS, DESFA S.A. prepares a NDP according to article 68 (2) of Law 4001/2011 and the NNGS network code. The NDP is approved by RAE, according to the provisions of article 14 of Law 4001/2011. DESFA S.A. submitted an NDP[16] for the period 2021-2030 with a total budget of 543,635,880 €, which included significant new NNGS expansion projects in new areas such as the high-pressure pipelines to Western Macedonia and Patras.

Since 2001, three local monopolies have been operating under a concession regime - granted for an emerging market – having the activities of both distribution and supply in each of their areas. By Law 4336/2015, the concession ended prematurely and since 1.1.2017 three unbundled distribution companies were formed through spin-off: EDA Attikis in the municipal area of Attika (Athens), EDA Thessalonikis-Thessalias in the areas of Thessaloniki and Thessalia and DEDA in the rest of the country. During 2021, the Greek State ran an international tender to sell the holding company of the three DSOs, DEPA Networks. Italgas Newco Srl, a subsidiary company of the Italian DSO, Italgas SpA, was pronounced the successful bidder and on 10.12.2021 a Sales Purchase Agreement was signed, with the certification of the distribution companies by RAE under the new regime as a precondition.[17,18]

The same Law 4336/2015 foresees that in case a municipality is not included in the 5-year NDP of one of the three DSOs, a third party may file an application for a distribution license in that area. In this context, HENGAS

[16] The NNGS Development Plan is available in English at: https://www.desfa.gr/userfiles/5fd9503d-e7c5-4ed8-9993-a84700d05071/TYDP%202021%202030%20-%20fin_clean.pdf

[17] In March 2019, the Greek government adopted, by Article 53 of Law 4602/2019, the Ownership Unbundling Model for the distribution networks (excluding the already established DSOs) in order to ensure the complete independence of the DSOs,[17] to avoid exchanges of confidential information, and to ensure competition at the supply market.

[18] The certification took place in 2022.

S.A. received a distribution license for 9 municipalities during 2020 and 2021 and was certified as an ownership unbundled DSO in 2021. The first 5-year Distribution NDP[19] for the period 2022-2026 amounts to 55,554,125 €.

Revision of the regulatory framework for Remote Distribution Networks

The Regulatory Framework for the development of Remote Distribution Networks 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 to the Regulator for approval of the Natural Gas Distribution Network Development Plan, the DSO may propose the construction of a Remote Distribution Network. This proposal must be accompanied by a suggested method of gas supply to the Remote Network as well study that compares the cost of a virtual pipeline through the alternative methods of supply (e.g. through CNG or LNG and through which route) to the cost of connecting the network through a pipeline.

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 consumer, 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.

RAE approves the maximum price per kWh, depending on the distance covered by the virtual CNG/LNG pipeline for the next year, as well as the terms and conditions of the tender carried out by the Operator.

In 2021, RAE adopted Decision 633/2021 which amended Decision 643/2018 to expand the concept of the Virtual Pipeline to include the Virtual Interconnection, i.e., virtual connection between different distribution networks (operated by different DSOs) or from the high-pressure network. The case of gas supply through LNG was also further elaborated, in view of the operation of a truck-loading facility on the Revithousa LNG Terminal.

[19] Available in Greek only at: https://www.hengas.gr/wp-content/uploads/2022/02/%CE%A6%CE%95%CE%9A-B-680_15.02.2022.pdf

4.1.1 Network and LNG access tariffs

A. Transmission System and LNG terminal access tariffs

In June 2019, RAE adopted Decision 540/2019 which set the Required Revenue for the Transmission System and LNG Facility in Revithoussa for the regulatory period 2019-2022. The following table contains the Required Revenue per basic NNGS service. Decision 540/2019 also lists in detail the main parameters of the WACC as they are presented in Table 27.

Year	Basic Transmission Service[20]	Basic LNG storage service	Total Sum
2019	101,807,713	42,509,863	144,317,576
2020	101,098,410	41,112,281	142,210,691
2021	99,084,171	40,508,395	139,592,566
2022	98,416,388	39,795,811	138,212,199

Table 26: Required Revenue per basic NNGS service (€/year)

	2019	2020	2021	2022
Risk-free rate	0.35%	0.35%	0.35%	0.35%
Country Risk Premium	2.00%	1.80%	1.50%	1.50%
Equity Beta	0.80	0.80	0.80	0.80
Market Risk Premium	5.30%	5.30%	5.30%	5.30%
Return on Equity (nominal, post-tax)	6.59%	6.39%	6.09%	6.09%
Tax Rate	28%	27%	26%	25%
Return on Equity (nominal, pre-tax)	9.16%	8.76%	8.23%	8.12%
Gearing Ratio (G)	18.37%	18.90%	16.38%	16.10%
Debt Interest Rate	4.14%	3.93%	3.92%	3.91%
Total WACC (nominal, pre-tax)	8.23%	7.84%	7.52%	7.44%

Table 27: Main parameters of WACC- DESFA S.A. - 2019-2022 (Decision 540/2019)

RAE Decision 512/2021 approved DESFA's network tariffs for 2022, based on DESFA's proposal in accordance with the provisions of articles 5 and 18 of the Tariff Regulation. Because of the unexpectedly sharp increase in gas consumption in 2020, as the Recoverable Difference for the year 2020 amounted to €47,018,304 (over-recovery), i.e. 33% on the accounting Allowed Revenue for 2020. If the Recoverable Difference were fully taken into account for the 2022 tariffs according to the Tariff Regulation, a sharp tariff decrease would result, followed by a re-increase in 2023 when significant investments are planned. In order to avoid significant fluctuations that would disturb the market, RAE decided to distribute the Recoverable Difference of the year 2020 as follows:

a) an amount of 4.5 M€ of the over-recovery related to Entry Point revenue to reduce the Allowed Revenue for the NNGS Entry Points for the year 2022 and the remaining amount, to reduce the Allowed Revenue for the years of the next Regulatory Period 2023-2026 by the same amount, taking into account the annual inflation and b) an amount of 3.7 M€ to reduce the Allowed Revenue of the LNG Tariffs for the year 2022 and the remaining amount to equally reduce the Allowed LNG Revenue for the next Regulatory Period 2023-2026, taking also inflation into account.

[20] The Required Revenue for the basic transmission service is allocated by 50% to the Entry Points and 50% to the Exit Points of the Transmission System.

With reference to the Recoverable Difference resulting from the NNGS Exit Points, DESFA proposed that it should be offset in its entirety with the Old Recoverable Difference of the period 2006-2016[21], in accordance with the provisions of article 19B (3) of the Tariff Regulation. RAE Decision 512/2021 approved the above proposal and revised the tariff coefficients as well as the values of the B Multipliers.

The Decision for transmission tariffs according to the new tariff regulation (Decision 512/2021) will be in force from 1.1.2022.

Transmission System for each Entry and Exit	**SDM$_i$ (€/kWh GCV /Hour/Year)**	**SEM (€/kWh GCV)**	**SDDY (€/kWh GCV /Hour/Year)**
Entry Sidirokastro	4.1717691	-	-
Entry Ag. Triada	1.3247007	-	-
Exit Sidirokastro*	4.1717691		
Exit North Zone	2.7290326	0.0001516	1.0287738
Exit South Zone	3.0732256	0.0001516	1.0287738
LNG Tariffs	**SDY (€/kWh GCV /Hour/Year)**	-	-
LNG Facility	2.9684484	-	-
**A reverse-flow Exit Interconnection Point is charged with the tariffs of the respective Entry Point, based on article 9 (6) of the tariff regulation.*			

Table 28: Natural Gas Transmission Tariffs coefficients for 2022

B. Distribution System access tariffs

In November 2020, RAE issued Decisions 1428/2020, 1429/2020 and 1430/2020 that approved the Required Revenue and the distribution tariffs for the DSOs of Attica, Thessaloniki-Thessaly and DEDA respectively for the Regulatory Period 2019-2022, according to the gas distribution tariff regulation (RAE's Decision 328/2016).

Furthermore, the above three Decisions approved the provision of incentives for certain investments by increasing the WACC by 1.5% based on achieving specific milestones for the years 2020 to 2022. The above increase is granted from the year of achievement of the milestone and for the next three years onwards, giving a strong incentive to the DSO for the timely implementation of the approved network development plan.

	2019	2020	2021	2022
Risk-free rate	0.35%	0.35%	0.35%	0.35%
Market Risk Premium	5.30%	5.30%	5.30%	5.30%
Beta	0.80%	0.80%	0.80%	0.80%
Gearing (loan)	16%	18%	20%	20%
Country Risk Premium	2.00%	1.80%	1.50%	1.50%
Cost of equity (post-tax)	6.59%	6.39%	6.09%	6.09%
Tax rate	28%	24%	24%	24%
Cost of equity (pre-tax)	9.15%	8.41%	8.01%	8.01%
Debt rate	3.08%	3.08%	3.08%	3.08%
Total WACC (nominal, pre-tax)	8.18%	7.45%	7.03%	7.03%

Table 29: Main parameters of WACC- Gas Distribution 2019-2022 (Decisions 1428/2020, 1429/2020 and 1430/2020)

[21] During the years 2002-2016, large under-recovery took place because of the sharp decrease of gas consumption due to the country's economic recession. This under-recovery (Old Recoverable Difference) is by law to be recovered in a 20-year period.

In July 2021, RAE adopted Decision 615/2021, which set the Required Revenue and the distribution tariffs for the DSO HENGAS S.A. for the Regulatory Period 2021-2024. The nominal pre-tax weighted average cost of capital was set at 7.03% for each year of the Regulatory Period 2021-2024.

In 2021, the distribution tariffs were adjusted based on the annual Consumer Price Index of 2020, as per the Distribution Code provisions. Therefore, the regulated distribution tariffs of 2021 were the following:

	Attica	Thessaloniki	Thessaly	Central Greece	Peloponnese	Central Makedonia	Eastern Macedonia-Thrace	Western Macedonia	Western Greece	Epirus	HENGAS
	Capacity charges €/MW/h (2021)										
Households	1,057.3054	374.0376	431.4291	851.5837820	N/A	688.7565614	521.7600584	1,157.6361017	720.4643773	665.9128894	1.357,4459
Commercial	1,057.3054	374.0376	431.4291	851.5837820	N/A	699.0254600	573.0802234	1,154.5169844	740.9977061	689.7288776	1.357,4459
Industrial	4,252.8639	1,496.5317	1,725.2177	6,912.2981137	10,753.8736395	4,455.8178311	6,419.7073435	6,162.3460028	3,192.8128171	3,611.3010166	4.154,5289
A/C, Cogeneration	1,056.7248	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0	0
CNG	4,252.8639	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0	0
Other	N/A	N/A	N/A	6,824.5367846*	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Energy charges €/MWh (2021)										
Households	14.1934	10.3554	10.5551	20.2891574	N/A	17.5638520	15.3816018	20.8689526	17.5738810	13.7497549	16,0482
Commercial	14.1934	10.3554	10.5551	9.2352168	N/A	7.1618954	8.4303153	16.6664057	11.4398088	9.6744074	16,0482
Industrial	0.4844	0.1590	0.1535	0.5589428	0.7257618	0.5042302	0.6404657	0.6824683	0.5232952	0.3919253	0,7390
A/C, Cogeneration	2.6164	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CNG	0.4844	0.9344	0.7418	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Other	N/A	N/A	N/A	0.5564819*	N/A	N/A	N/A	N/A	N/A	N/A	N/A
*Interconnection Attica-Boeotia											

Table 30: Capacity and energy charges per distribution network per consumer category

4.1.2 Balancing

According to the provisions of EU Regulation 312/2014 (BAL NC), transmission users are responsible for balancing their inputs and outputs using balancing rules designed to promote a short- term wholesale gas market and participating in trading platforms established to better facilitate gas trade between network users and the transmission system operator. The TSOs carry out any residual balancing of the transmission networks that might be necessary. Throughout 2021, RAE participated actively in the establishment of the regulatory framework for the operation of a trading platform by Hellenic Energy Exchange (HENEX) according to the provisions of BAL NC and the Greek Law 4425/2016. For the purpose of procurement of short-term standardized products, DESFA shall trade on this trading platform and will terminate the operation of the existing Balancing Platform.

In order to enable network users to balance their balancing portfolios, BAL NC sets out minimum requirements for information provisions. The information flows aim to support the daily balancing regime and seek to be a set of information to support the network user in managing its risks and opportunities in a cost-efficient way. Especially for Users supplying non-hourly metered consumers, information is limited as it is not based on real measurements but on estimates. BAL NC, taking into account the differences among the European natural gas markets, provides three alternative information models and the responsible NRA decides on the model which suits better the balancing zone. RAE with its Decision 780/2020 (Gazette B' 1949/21.05.2020) chose the model based on which the information on the non-daily metered off-takes consists of forecasts of the same day or the day before, as the model that will be implemented in the NNGS. In addition, the NRA must designate the Forecasting Party that will be responsible for the forecasting of the non-daily metered Users' off-takes. RAE consulted with the Operator of the NNGS and the DSOs, as provided in the BAL NC, and proceeded with the designation of the Forecasting Party. In particular, DESFA was designated as the responsible Forecasting Party to forecast the non-daily metered withdrawals of Transmission System users.

According to the regulatory framework, every year the TSO submits to RAE for approval an annual planning for balancing gas. The 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 framework contract for purchasing balancing gas for the next year. DESFA can buy or sell balancing gas throughout balancing platform, in near future, around March 2022, through trading platform. If this is not possible DESFA can procure balancing gas under contracts signed with suppliers derived from an international tender procedure (balancing services). According to the Greek Energy Law, DESFA can buy balancing gas directly from DEPA's long-term LNG contract signed before 2004. In this case balancing gas price is approved by RAE.

RAE approved the annual balancing plan submitted by DESFA for the year 2022 with Decision 469/2021. TSO's estimation on balancing gas needs was 1.33% of the total estimated gas demand (797,245 MWh) for purchasing gas and 0.92% (544,420 MWh) for selling. It is estimated that 22% of the total required balancing gas will be purchased through balancing services (the rest expected to be traded on the Balancing Platform established by the TSO, according to Regulation 312/2014 and the Interim Measures approved by RAE). The total quantity of balancing gas injected into NNGS using balancing services within 2021 amounted to 54,639 MWh.

RAE is also responsible for approving the parameters involved in the calculation of balancing cost and the methodology for allocating these costs to the Transmission System users. With Decision 498/2021 (Gazette B' 3530/03.08.2021), RAE approved the balancing cost allocation scheme and the relevant shippers' charges, for 2021. 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.

4.1.3 Cross-border issues

4.1.3.1 Gas Interconnector Greece–Bulgaria (IGB)

In June 2019, ICGB AD requested the postponement of the deadline for the commercial launch of the operations of the IGB pipeline until January 2021 instead of July 2020 as it was provided in the Exemption Decision. According to the company, the delay in the commencement of the commercial operation of the pipeline was due to the delay in the construction work because of objections and litigation in the contract award procedures. This request constituted an amendment to the Exemption Decision and could only be made following a new Joint Decision by the NRAs. The Directorate-General for Energy of the European Commission confirmed that it didn't need to take any action on amending the Exemption Decision as long as the deadline of Article 36 (9) of the 2019/73/EC Directive is complied with. Although the reasons for the delay cited by the company appeared to be objective and beyond its control, RAE and EWRC sought the consent of users who had entered into Advanced Reservation Capacity Agreements (ARCAs) with the company, so that the modification of the Exemption Decision would not affect their business plans. RAE and EWRC jointly approved the requested amendment of the Exemption Decision (Decision 568/10.03.2020), according to which, the starting data of the commercial operation of the pipeline would be 1 July 2021. On April 13th 2021, ICGB AD requested a second amendment of the Final Joint Decision for a further delay of the COD until July 1st 2022. In this regard, a second amendment of the Exemption Decision was approved by the two regulatory authorities and the commercial operation date deadline was set for 1 July 2022 (Decision 424/2021)[22].

4.1.3.2 Chiren UGS expansion

This PCI project concerns the expansion of the underground natural gas storage (UGS) facility located in Chiren, Bulgaria. Today the gas storage has a maximum capacity of 550 million cubic meters (mcm), and the goal is to increase its capacity to 1 billion cubic meters (bcm). From the cross-border cost allocation (CBCA) presented by the project promoter company, Bulgartransgaz EAD, a total net benefit index for Greece of 8.2%, for Romania 17.5% and for Bulgaria 70.0%, Serbia (3.9%), and Bosnia and Herzegovina (0.4%). Taking into account Romania's decision not to participate in the project, EWRC and RAE decided that the total cost of the investment would be allocated to Bulgaria and recovered from the tariffs of the Bulgarian natural gas system.[23]

4.1.3.3 Trans Adriatic Pipeline (TAP)

According to TAP AG's Exemption Decision, every two years the TAP should make an evaluation to increase the pipeline's transmission capacity. Within 2021, RAE, ARERA and ERE examined the possibility to increase TAP's capacity to 20 bcm/y through a market test, in accordance with European Union best practices, based on demand and cost-effectiveness. In this context, in 2019 a market test procedure began. Within 2021, RAE with Decision 426/2021 approved the incremental capacity project proposed by TAP, SNAM and DESFA, and set the f-factor to be equal to 0.75, in accordance with Article 23 of the CAM NC. RAE's Decision 426/2021, specifies, among other, the procedure to be followed in the event of a positive outcome of the financial evaluation of the binding offers for booking incremental capacity. The procedure ends with the execution of Gas Transportation

[22] More information on the second amendment of the IGB Exemption Decision (RAE Decision 424/2021) is available at: https://www.rae.gr/wp-content/uploads/2021/05/424_2021.pdf.

[23] The Cross-border Cost Allocation Agreement between the Energy and Water Regulatory Commission (EWRC) and the Regulatory Authority for Energy (RAE) is available in English at: https://www.rae.gr/wp-content/uploads/2021/09/6%CE%A3%CE%A53%CE%99%CE%94%CE%9E-%CE%9330.pdf.

Agreement at the "Nea Mesimvria" interconnection point between the transmission user, to whom capacity will be allocated, and DESFA. With Decision 470/2021 RAE approved the relevant Gas Transportation Agreement.[24]

In addition, the process of conducting the second market test of TAP began in 2021 and TAP operator submitted his proposal for defining the Guidelines on the basis of which the first phase of the Market Test of the year 2021 will be conducted, which do not differ from the Guidelines of the market test of 2019. Decision 517/2021 of the Regulatory Authorities of Italy, Albania and Greece approved the proposal of the TAP operator regarding the guidelines to conduct the new market test.

4.1.3.4 Capacity products

In August 2020, DESFA submitted a proposal to RAE for offering Competing and Conditional Capacity products. This proposal was approved by RAE Decision 1399/2020 (Gazette B' 4622/21.10.2020), after a public consultation was held. Specifically, the tenders for Competing Capacity at the Entry Points of "Kipi" and "Nea Mesimvria" were approved, with a specific schedule and conditions, depending on the final start date of the commercial operation of TAP. Furthermore, to maximize the booking capacity that can be offered at the northern entrances of the country, it was decided to offer additional capacity equal to 40,000,000kWh / Day in the form of a service of Conditional Capacity at the Entry Point of "Nea Mesimvria", with the following Capacity Use Condition: The total amount of natural gas that enters to the NNGTS from the northern Entry Points of NNGTS (Sidirokastro, Kipi and Nea Mesimvria) is less than or equal to the total technical capacity of the northern Entry Points of the NNGTS (171,172,292 kWh/Day). Based on historical data, the probability of not using the full capacity was estimated at 3.5% and this service was offered at a 10% discount.

RAE evaluated the Operator's proposal and the comments received in the context of public consultation and approved Decision 471/2021, which established the conditions for the Conditional Capacity products at the "Nea Mesimvria" Interconnection Point for the Gas Year 2021-2022. According to RAE's decision, DESFA must review its proposal and make a new recommendation to RAE regarding the List of Conditional Capacity Points in the event that the gas flows in the NNGTS change significantly (indicatively, completion of system upgrade, start of commercial operation of new Entry Point), no later than April 30, 2022.

However, additional interest was recorded by the gas shippers to book additional capacity at the "Kipi" Entry Point for the gas year 2021-2022, possibly also through Conditional Capacity, contributing to the further utilization of the transport capacity of the NNGTS. In this context, the Operator, taking into account the already booked capacities of the Conditional Capacity at the "Nea Mesimvria" Interconnection Point, proposed the amendment of Decision 471/2021. DESFA's proposal, which was put out for public consultation, includes: a) the allocation of the remaining Conditional Capacity offered at the "Nea Mesimvria" Interconnection Point - the difference between the already booked Conditional Capacity and the offered 30,000 MWh per day, through competitive auctions at the "Nea Mesimvria" and "Kipi" Interconnection Points from 01.01.2022, b) the maintenance of the same Capacity Usage Condition, which is as follows: "The total amount of natural gas that naturally enters the NNGTS from its northern IPs (Koulata - Sidirokastro, Kipi and Nea Mesimvria) is less than or equal to the total of the technical capacity of the northern entrances of the NNGTS (171,172,292 MWh/Day)" and c) the allocation of the remaining Conditional Transmission Capacity through auctions, which for the quarterly and monthly products will be held one week after the start of the corresponding auctions for the allocation of uninterrupted transmission capacity, while for the daily and intraday products, in parallel with the corresponding auctions for uninterrupted transmission capacity. RAE Decision 1033/2021 approved DESFA's proposal for the amendment of Decision 471/2021 so that the remaining Conditional Transmission Capacity is made available through competitive auctions at the Interconnection Points of "Nea Mesimvria" and "Kipi",

[24] The template can be accessed at: https://www.desfa.gr/userfiles/5fd9503d-e7c5-4ed8-9993-a84700d05071/Approved%20by%20RAE,%20GTA_1.docx.

starting from 01.01.2022, 07:00 and set the offered Conditional Transmission Capacity allocated for the period 01.01.2022 – 01.10.2022.

4.1.4 Implementation of Network Codes and guidelines

(A) In 2021, RAE, within the framework of Regulation (EU) 312/2014 establishing a Network Code on Gas Balancing of Transmission Networks (BAL NC), published the following Decisions:

1. Decision No. 70/2021 on the designation of a forecasting party in the Balancing Zone of the National Gas Transmission System, in accordance with Article 39 (5) of Regulation (EU) 312/2014.
2. Decision No. 1060/2021 on the amendment of the National Natural Gas System Code – Completion of the Seventh Revision.
3. Decision No. 1061/2021 on the amendment of the National Natural Gas Transmission System Balancing manual.

(B) In 2021, RAE, within the framework of Regulation (EU) 2017/459 establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) No 984/2013, published the following Decisions:

1. Decision No. 471/2021 on the allocation of Conditional Capacity products in the "Nea Mesimvria" Interconnection Point for the gas year 2021-2022.
2. Decision No. 1033/2021 on the amendment of Decision 471/2021 regarding the allocation of Conditional Capacity products in the "Nea Mesimvria" Interconnection Point for the gas year 2021-2022.

(C) In 2021, RAE, within the framework of Regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures for gas (TAR NC), published the following Decisions:

1. Decision No. 512/2021 on the tariff adjustment for the use of the National Natural Gas System for 2022.
2. Decision No. 116/2021 on the approval of the National Natural Gas System Network Development Plan for the 2021-2030 period.

4.2 Competition and market functioning

4.2.1 Wholesale markets

In 2021, there was extensive collaboration between RAE, the natural gas Transmission System Operator (TSO) DESFA, and the Energy Exchange HENEX to establish the Greek Trading Platform. The entire framework, along with relevant regulations and decisions for the Trading Platform, and DESFA's proposal to amend the National Natural Gas Transmission System Network Code, were subject to public consultation by RAE from June 29, 2021, to September 20, 2021. A prerequisite for the Trading Platform was the licensing of the Energy Exchange as an operator and the approval of ten regulatory decisions that collectively defined the secondary framework for operating the natural gas Trading Platform. RAE approved two of these decisions at the end of 2021 and the remaining eight at the beginning of 2022.

Furthermore, the procedure for conducting the annual LNG planning at Revythoussa was evaluated after the first year of implementing the auction scheme. This evaluation led to amendments to the National Natural Gas Transmission System Network Code and the LNG auction manual. RAE approved the organization of auctions for conditional capacity of 30,000 MWh per day at the entry point "New Mesimvria" for the period from October 1, 2021, to October 1, 2022. Additionally, an amending decision approved competitive auctions between the entry points Kipi and Nea Mesimvria for the remaining conditional capacity.

Furthermore, it is noteworthy that the number of companies which are actively importing natural gas in Greece has been gradually increasing in the recent years to 10 companies in 2021. This number reflects the intense activity in the natural gas market of the county.

Monitoring of prices

RAE is the competent authority to monitor the Greek energy market. Within this framework, the regulator is publishing monthly data on the calculated Weighted-Average Import Price (WAIP) of natural gas in the NNGS. The publication of data on the WAIP,[25] in combination with the publication of data on Balancing Gas Reference Price, Balancing Gas Marginal Sell and Balancing Gas Marginal Buy Prices 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 take advantage of business opportunities and enhance competition, to the benefit of consumers. Furthermore, the publication of wholesale prices constitutes a necessity for the organization of a wholesale gas market where the prices are determined real-time by supply and demand on a trading platform. Figure 12 presents the monthly WAIP as well as the prices for the balancing gas for the same month, as announced on the internet site of DESFA, from January 2019 to January 2022.

[25] For more information visit our website at: https://www.rae.gr/en/natural-gas/market/import-prices/.

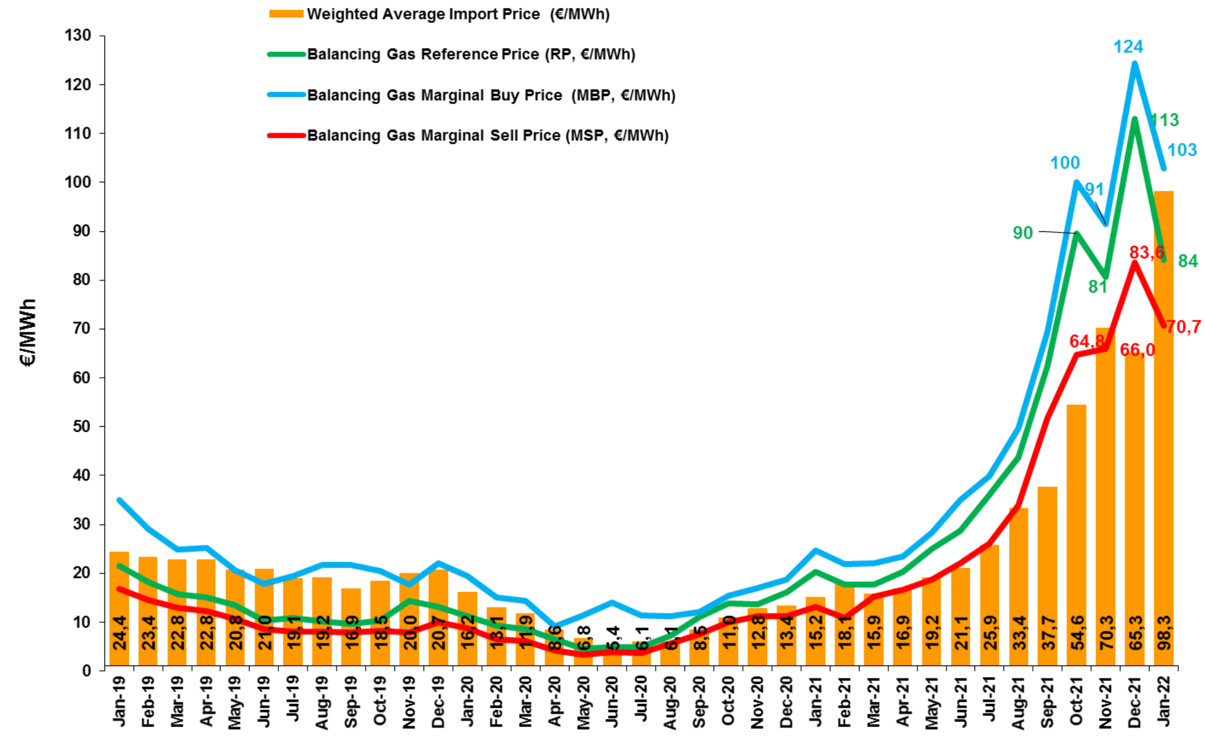


Figure 12: Price Monitoring in the Wholesale Natural Gas Market in 2019-January 2022

4.2.1.1 Other regulatory developments in the wholesale natural gas markets

DIORIGA GAS S.A. FSRU market test

In 2021, the company DIORIGA GAS S.A., operating a FSRU, submitted an application to RAE, for the exemption from the Articles 32, 33 and 41 of Directive 2009/73/EC. In parallel, the market test process for the floating LNG storage system planned by the Dioriga Gas company in the Corinth area also began. RAE with Decisions 700/2021 and 789/2021 approved the Guidelines and the Expression of Interest (EoI) Notice for the participation in the Non-Binding Phase of the market test, according to article 36 (6) of the Directive 2009/73/EC. The Non-Binding phase started on 22.10.2021 and was initially planned to end on December 10, 2021.

Due to the SARS-COV-19 pandemic and the extraordinary conditions affecting natural gas and electricity prices in order to facilitate interested parties in collecting the necessary supporting documents and signing the relevant Confidentiality Agreements, procedures DIORIGA GAS S.A. submitted to RAE a request to extend the deadline for submitting non-binding offers by 35 days, until January 14, 2022. RAE approved the extension of the timeline with Decision No. 968/2021. The non - binding phase of the market test ended in the beginning of 2022, during which great interest was expressed by market participants.

4.2.2 Retail market

In 2018 the natural gas market was fully liberalised as major changes were introduced in the retail 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 thereafter the gas supply companies may operate on the market, without any geographical restriction, provided that there is an active network 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. The year 2021 was the fourth year of full liberalization of the natural gas retail market.

At the end of 2021, a total of 22 suppliers were active, out of the total of 24 holding natural gas suppling license, in the retail market of natural gas:

	Supplier Name:
1.	ANOXAL
2.	BA GLASS
3.	PPC
4.	DEPA
5.	ELVALCHALCOR
6.	ELINOIL
7.	ELPEDISON
8.	ZENITH
9.	EFA ENERGY
10.	FULGOR
11.	FYSIKO AERIO ELLADOS
12.	GREENSTEEL
13.	HERON
14.	KEN
15.	MNG TRADING
16.	MOTOR OIL
17.	MYTILINEOS
18.	NRG
19.	PETROGAZ*
20.	PROMETHEUS
21.	SIDENOR
22.	SOVEL
23.	VOLTERRA
24.	WATT & VOLT
(25).	Supplier of Last Resort - NRG
*Ceased activity within 2021	

Table 31: Suppliers active in the retail market of natural gas (2021)

The Herfindahl-Hirschman Index (HHI) at the end of the year is estimated at 2,079 for based on total gas consumption volume. However, if we calculate the HHI index separately for each distribution network, then it will be noticed that the market concentration is significantly higher.

The tables below represent the connections (Table 32) and consumption (Table 33) per category of consumers per supplier including the suppliers market shares.[26]

Supplier	Number of connections (DEC 2021)				Market share
	Household	Commercial	Industrial	Total	
ZENITH	306,940	8,232	70	315,242	55.50%
EPA ATTIKIS (FYSIKO AERIO)	139,829	6,351	71	146,251	25.75%
MYTILINEOS	25,245	660	52	25,957	4.57%
ELPEDISON	20,278	484	6	20,768	3.66%
HERON	16,728	578	62	17,368	3.06%
NRG	14,289	600	4	14,893	2.62%
EFA ENERGY	8,274	355	5	8,634	1.52%
WATT & VOLT	8,046	314	0	8,360	1.47%
PPC	6,850	68	0	6,918	1.22%
VOLTERRA	1,680	170	2	1,852	0.33%
KEN	1,363	35	0	1,398	0.25%
ELINOIL	281	19	1	301	0.05%
DEPA	17	18	45	80	0.01%
HELLENIC HALYVOURGIA	0	2	9	11	0.00%
GREENSTEEL	0	0	2	2	0.00%
PROMETHEUS GAS	0	0	1	1	0.00%
ANOXAL	0	0	1	1	0.00%
FULGOR	0	0	1	1	0.00%
SIDENOR	0	0	1	1	0.00%
SOVEL	0	0	1	1	0.00%
PETROGAZ	0	0	0	0	0.00%
MNG Trading	0	0	0	0	0.00%
MOTOROIL	0	0	0	0	0.00%
NRG (SoLR)	0	0	0	0	0.00%
BA GLASS	0	0	0	0	0.00%
TOTAL	549,820	17,886	334	568,040	100.00%

Table 32: Natural gas connections per category of consumers and suppliers' market share, December 2021 (Source: Natural gas DSOs')

[26] Please note that the tables do not take into account the consumption and connection data of consumers that are directly connected to the high-pressure transmission system. There are 19 metering points that are connected to the transmission system.

Supplier	Consumption (MWh)				Market share
	Household	Commercial	Industrial	Total	
ZENITH	3,204,760	593,758	615,108	4,413,627	33,8%
EPA ATTIKIS (FYSIKO AERIO)	2,063,903	929,230	447,788	3,440,921	26,4%
MYTILINEOS	267,951	54,925	1,167,710	1,490,587	11,4%
HERON	139,688	57,357	731,366	928,411	7,1%
HELLENIC HALYVOURGIA	0	552	726,840	727,392	5,6%
MNG Trading	0	25	10,011	10,037	0,1%
DEPA	194	72,715	518,406	591,316	4,5%
GREENSTEEL	0	0	256,336	256,336	2,0%
ELPEDISON	199,960	31,493	42,880	274,333	2,1%
BA GLASS	0	0	0	0	0,0%
EFA ENERGY	86,105	31,897	41,130	159,133	1,2%
NRG	137,440	72,462	62,858	272,760	2,1%
MOTOROIL	0	0	0	0	0,0%
WATT & VOLT	75,804	18,771	0	94,576	0,7%
SOVEL	0	0	57,685	57,685	0,4%
SIDENOR	0	0	106,643	106,643	0,8%
FULGOR	0	0	47,299	47,299	0,4%
ANOXAL	0	0	49,078	49,078	0,4%
VOLTERRA	17,136	29,432	23,716	70,284	0,5%
PPC	37,939	3,413	0	41,352	0,3%
PROMETHEUS GAS	0	0	8,138	8,138	0,1%
KEN	11,151	1,374	0	12,526	0,1%
ELINOIL	2,874	2,483	0	5,357	0,0%
PETROGAZ	559	41	0	600	0,0%
TOTAL	6,245,465	1,899,930	4,912,995	13,058,389	100%

Table 33: Natural gas consumption (MWh) per category of consumers and suppliers' market share, 2021 (Source: Natural gas DSOs')

Table 34 portrays the number of consumers who switched supplier in 2021, as well as their corresponding consumption. As it turns out, the highest switching rate was recorded in the category of household consumers, followed by industrial and commercial consumers, reversing the previous trend of 2020 when the highest percentage of switching was recorded in the category of commercial consumers.

Overall, consumer switching rate in 2021 slightly increased compared to 2020 in terms of connections (due to increased mobility of household and commercial consumers), while there was a slight decrease in terms of consumption (mainly due to the decreased consumption of commercial consumers).

Consumer Category	Total number of consumers	Number of consumers switching Supplier	Percentage of switching (Number of consumers) %	Consumers' total consumption (MWh)	Consumers' consumption switching Supplier (MWh)	Percentage of switching (in volume) (%)
Household	549,814	25,432	4,63%	6.178.583	243.739	3,9%
Commercial	17,883	1,067	5,97%	1.967.827	90.574	4,8%
Industrial	338	11	3,25%	4.988.130	269.469	5,4%
Total number	568,035	26,510	4,67%	13.134.540	603.782	4,6%

Table 34: Consumers switching their natural gas supplier per consumer category, 2021 (Source: Natural gas DSOs' data)

The companies "Zenith SA" and "Fysiko Aerio – Hellenic Energy Company" were the prevailing natural gas suppliers in the retail gas market (household, commercial and industrial consumers), representing 55.5% and 25.75%, respectively, of the total number of connections at the end of 2021 and the 33.8% and 26.35% of the total natural gas volume consumed.

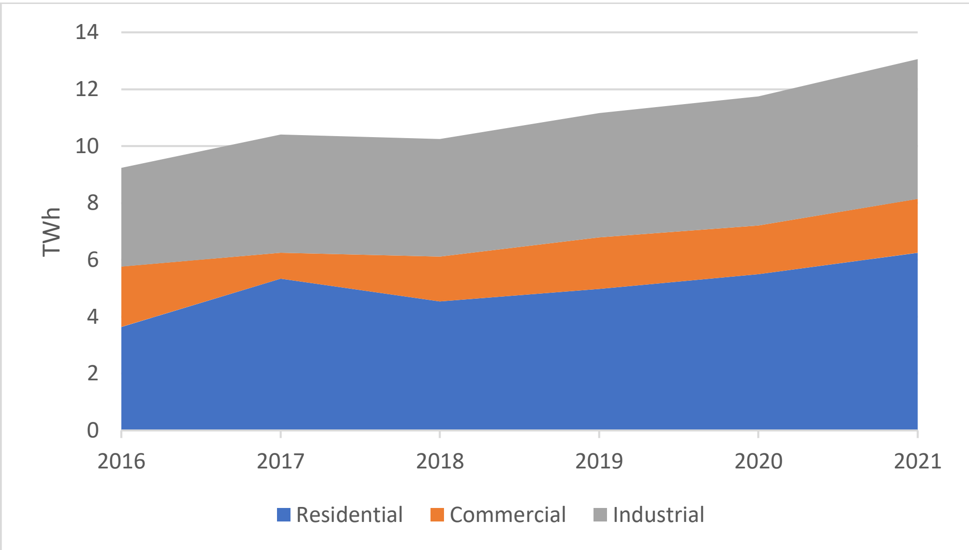


Figure 13: Natural Gas Consumption per consumers' category in the distribution networks (2016-2021)

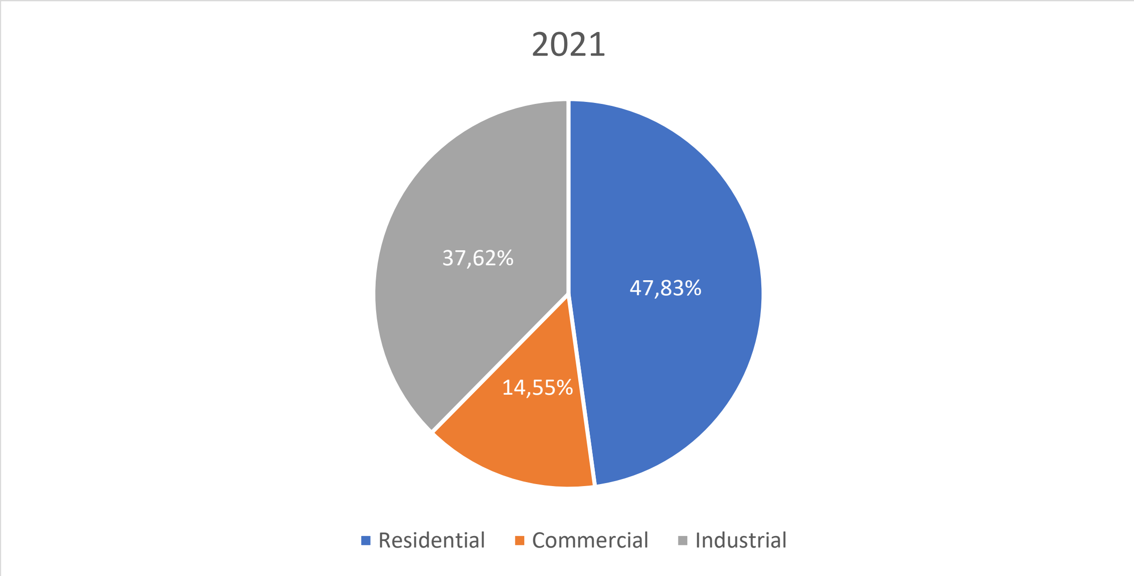


Figure 14: Natural Gas Consumption percentage per consumer category in the distribution networks (2021)

Households' consumption share reached 47.83%, industrial users share amounted to 37.62% and commercial users to 14.55% in the gas Distribution Networks of the country. More specifically, in 2021 household consumption was greatly increased by 13.77%, from 5.49 TWh to 6.24 TWh. In the industrial sector the consumption of natural gas also increased by 8.26% from 4.54 TWh to 4.91 TWh. The commercial sector recorded a growth in consumption as well, as it increased by 10.47%, from 1.72 TWh to 1.90 TWh.

In general terms, also considering the lockdowns which were imposed due to the COVID pandemic, the penetration of natural gas continued to record a strong positive trend in the Greek territory in 2021. The natural gas market was liberalized 4 years ago, therefore, it is reasonably expected to mature even further soon, unless the high energy prices that were recorded in the end of 2021 continue to persist, in which case a demand reduction for natural gas is foreseen.

Natural Gas Distribution Company	Category	Number of orders	Number of orders executed	Number of overdue orders executed
EDA Attica S.A.	**Households**	23,608	19,386	4,904
	Commercial	426	334	103
	Industrial	0	0	0
EDA Thessaloniki – Thessaly S.A	**Households**	25,589	9,866	907
	Commercial	580	187	22
	Industrial	10	0	0
DEDA S. A.	**Households**	484	484	0
	Commercial	12	12	0
	Industrial	4	4	0
Source: Natural Gas Distribution Companies				

Table 35: Statistical data of new natural gas connections (2021)

4.3 Other regulatory developments

RAE, with its Decision No. 214/2021, designated the company undertaking the role of the Supplier of Last Resort for Natural Gas for a period of 2 years from the publication of the relevant Decision. The Supplier of Last Resort is obliged to supply consumers, who are not represented by any Supplier, due to their previous Supplier's fault or due to events falling within the sphere of influence of their previous Supplier. The natural gas Supplier of Last Resort is obliged to supply consumers for a period of three (3) months, in order to give consumers adequate time to negotiate a new contract with a Supplier of their choice.

5 SECURITY OF SUPPLY

5.1 Security of Supply in Electricity Sector

RAE monitors the security of energy supply, particularly in relation to the balance of supply and demand in the Greek energy market, the level of projected future demand, the projected additional generation capacity, transmission and distribution of electricity and natural gas which is planned or under construction, the quality and level of maintenance and reliability of the Transmission Systems and Distribution Networks, the implementation of measures to cover peak demand, as well as the conditions of the energy market in relation to the possibility of developing new generation capacity.

Identification of national electricity crisis scenarios

According to Article 7 of Regulation (EU) 2019/941, on risk-preparedness in the electricity sector, RAE, as the competent authority prepared the study for the “Determination of the National Electricity Crisis Scenarios in the Interconnected System of the Country”. The completion of the study is expected within 2022 and its results will be the basis for the preparation of the National Electricity Risk Preparedness Plan, in accordance with the provisions of Article 10 of Regulation (EU) 2019/941, in order to ensure the most effective approach in the prevention, preparedness, management, and mitigation of the effects of an electricity crisis. The study will be drafted by RAE in cooperation with the TSO, the DSO, the Greek Energy Exchange, the National Competent Authority for Cybersecurity and the Ministry on Energy.

The national electricity crisis scenarios included in the study are determined based on at least the following risks, as mentioned in Article 5 par. 2 of the abovementioned Regulation:

a) Rare and extreme natural hazards
b) Accident risks which violate the N-1 criterion as well as extremely emergency situations
c) Subsequent risks, including the results of malicious attacks as well as fuel shortages

5.2 Security of Supply in Natural Gas Sector

5.2.1 Current demand

The total consumption of natural gas in 2021, as it is determined by the deliveries to the NNGTS, amounted to 69.96 TWh, an increase of about 10.87% compared to the consumption of natural gas in 2020 which amounted to 63.11 TWh. The consumption of natural gas in 2021 marked the highest gas demand level ever recorded in the country.

The highest percentage of natural gas consumption in Greece is absorbed for electricity production and, consequently, any variation in the demand of the electricity strongly affects the total gas consumption. Consumption in the electricity sector amounted to 48 TWh in 2021, an increase of 17% compared to 2020 (41 TWh).

At the same time, consumption for other uses decreased slightly by 1% and amounted to 21.9 TWh in 2021, compared to 22.1 TWh in 2020.

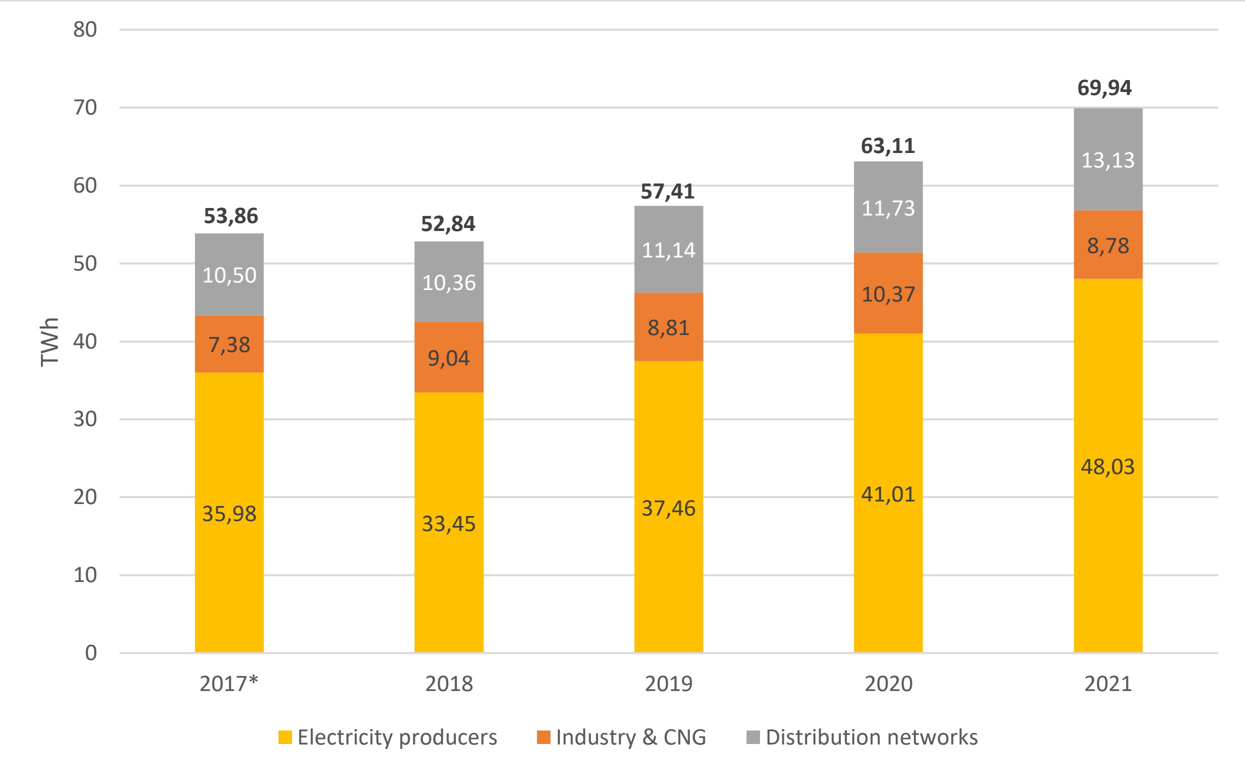
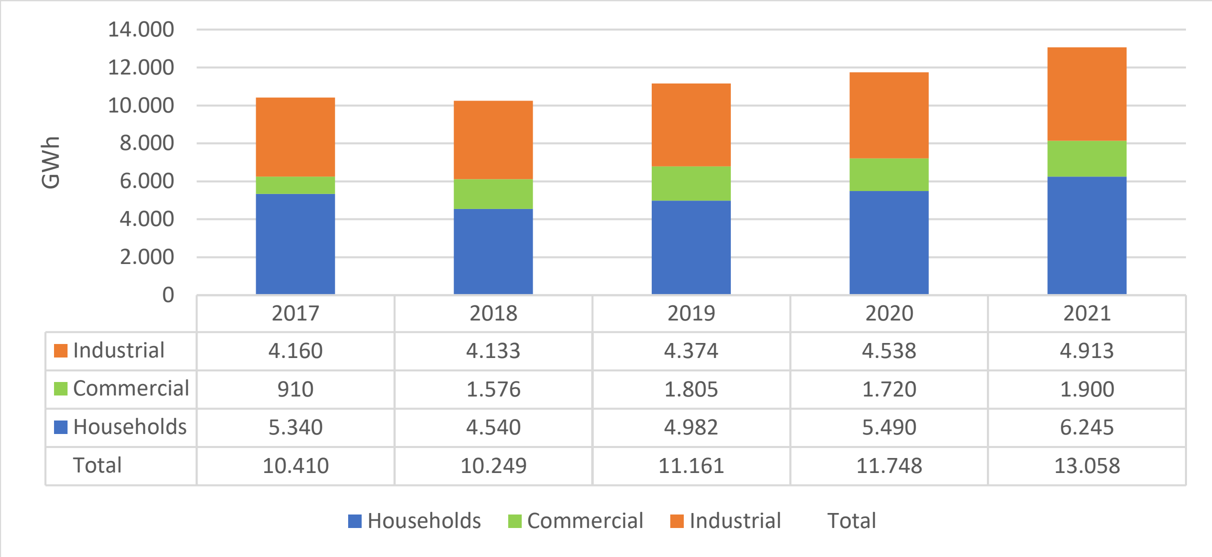


Figure 15: Natural Gas Consumption in the transmission system (Source: DESFA, 2017-2021)



	2017	2018	2019	2020	2021
Industrial	4.160	4.133	4.374	4.538	4.913
Commercial	910	1.576	1.805	1.720	1.900
Households	5.340	4.540	4.982	5.490	6.245
Total	10.410	10.249	11.161	11.748	13.058

Figure 16: Natural Gas Consumption in the distribution network (Source: DSOs, 2017-2021)

The total volume of gas consumption in the distribution networks in 2021 was increased for all categories of consumers compared to 2020.

RAE monitors the implementation of measures taken in the event of a crisis in the energy market. Especially for natural gas, RAE has been designated as the Competent Authority for ensuring the implementation of the Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010.

5.2.2 Projected demand

Based on DESFA's forecasts in 2020 for the total natural gas demand for the next decade according to DESFA's NNGS Development Study[27], the natural gas demand according to the basic scenario, was expected to range from 5,602 mNm³ in 2021 to 6,195 mNm³ in 2030. However, the high natural gas demand which was recorded in 2021 will lead to DESFA updating its gas demand estimations at the beginning of 2022.

Basic scenario - NECP adjusted	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Gas consumption by electricity producers	3,371	2,868	3,213	3,544	3,459	3,284	3,060	2,962	3,001	2,967
Consumers connected to high pressure network	816	817	874	878	924	928	928	932	929	929
Distribution networks	1,065	1,132	1,169	1,298	1,334	1,366	1,402	1,441	1,467	1,499
Reverse flow - Exports	350	350	430	505	635	710	800	800	800	800
Total gas transit	5,602	5,167	5,687	6,225	6,352	6,289	6,190	6,134	6,196	6,195
Source: NNGS Development study										

Table 36: Natural gas demand forecast for 2021-2030 in mNm³

5.2.3 National Preventive Action Plan

RAE in 2021 drafted the National Preventive Action Plan (PAP), as stipulated in the Regulation (EU) 2017/1938, regarding measures to safeguard the security of gas supply, in cooperation with the electricity and natural gas TSOs as well as the Ministry of Energy and approved it as the relevant competent authority. RAE then submitted the Plan to the competent Directorate of the European Commission through the CIRCABC platform.

The main objective of the PAP is to propose appropriate measures (actions) to reduce or eliminate risks that may affect the security of the country's natural gas supply. In this regard, the PAP has examined existing measures as well as the development of new actions related to:

- Increasing the utilization of existing gas infrastructure.
- Enhancing the availability of LNG during times of heightened risk.
- Increasing the level of preparedness of operators and other involved parties to address supply disruptions or risks.

For the identification and assessment of new actions, the RAE has relied on: a) The provisions of Regulation (EU) 2017/1938, b) The report of the JRC (Joint Research Center - Institute for Energy and Transport) on best practices

[27] For more information visit: https://www.desfa.gr/userfiles/pdf/f_%CE%9C%CE%B5%CE%BB%CE%AD%CF%84%CE%B7%20%CE%91%CE%BD%CE%AC%CF%80%CF%84%CF%85%CE%BE%CE%B7%CF%82%202021-2030_GR.pdf, page 7.

for the development of Preventive Action Plans and Emergency Plans (Good Practices for Preventive Action Plans and Emergency Plans, EUR 25210 EN - 2012). To achieve this, the following steps were followed:

- Identification of crisis scenarios based on the National Risk Assessment and setting priorities.
- Initial identification of actions that are considered feasible and can support the objectives of the Plan.
- Re-simulation of the scenarios and evaluation of the effectiveness of these actions in terms of risk reduction and compliance with the country's Infrastructure and Supply Rules.
- Estimation of the costs of these actions and their potential impact on the environment, market functioning, and the security of supply of other Member States.
- Development and application of a Multiple-criteria Decision Analysis model for the evaluation of these actions.
- Step-by-step simulation of the implementation of the actions and assessment of the remaining risks.

In addition to the above, the PAP addressed the ability to comply with the infrastructure standard (Rule N-1), along with a set of additional measures and obligations that enhance the risk prevention and safe operation of the system. Finally, it presents infrastructure projects crucial to the security of the country's gas supply, which have been included in the list of Projects of Common Interest (PCI List) and projects currently under construction in the DESFA’s TYNDP.

Following the consultation of the PAP, the following actions were decided upon:

- D1: Regulation for the extraordinary capacity offered by the Operator and allocation to Entry Points, *combined with one of following alternatives*:
- D2: Enhancement of LNG offloading schedule framework - schedule A
- D3: Enhancement of LNG offloading schedule framework - schedule B
- D4: Utilization of Revithoussa for maintenance of LNG EP seasonal reserve

Simultaneously, the PAP introduces a set of measures and obligations aimed at further strengthening and safeguarding the country's energy security proactively. These include:

- Development of specifications and guidelines for the establishment of Business Continuity Systems.
- An obligation on operators and licensees of electricity generation to comply with Business Continuity Systems.
- Design of a Risk Management System for the security of supply.
- Obligations for Transmission System Operators to conduct a documented assessment of demand.
- Obligations of natural gas suppliers, with specific information on their actions to ensure compliance with the Supply Rule, uninterrupted supply of Protected Consumers, and compliance with contractual obligations towards power generators during the whole winter period.
- Obligations of licensees of electricity generation from natural gas to document the adequacy of their actions to comply with the terms of their license and to ensure their operation.
- Exemption of diesel oil when used as an alternative fuel from the excise tax - duty.

5.2.4 Risk Groups

Based on Regulation (EU) 2017/1938, RAE participates in the currently active Algerian, Ukrainian and the Trans-Balkan Risk Groups. The Risk Groups strengthen regional cooperation and promote agreements on cross-border measures within and outside the Risk Groups, in order to increase the security of natural gas supply. Competent authorities cooperate with each other to carry out Joint Risk Assessment studies, capture the regional dimension of Preventive Action and Emergency Plans and draw up solidarity arrangements. More specifically, RAE, as the competent authority, participates in the drafting of Joint Risk Assessment studies of the above Risk Groups, in order to identify and assess multiple scenarios.

Furthermore, RAE, after an EU proposal, has been designated as the coordinator for the drafting of the Joint Risk Assessment study within the Trans-Balkan Risk Group, in which Greece, Bulgaria and Romania participate. The last Trans-Balkan study was completed in 2020, while the next one will be completed within 2022. In addition, RAE, together with the Italian competent authority, agreed to coordinate the drafting of a Joint Risk Assessment study within the Southern Gas Corridor - Caspian Risk Group, where Greece, Bulgaria, Croatia, Italy, Hungary, Malta, Austria, Romania, Slovenia and Slovakia participate.

6 Lists

6.1 List of tables

6.2 List of figures

6.3 List of abbreviations

ACER	Agency for the Cooperation of European Energy Regulators
aFRR	Automatic Frequency Restoration Reserve
AR	Allowed Revenue
ARCA	Advanced Reservation Capacity Agreement
ARERA	Italian Regulatory Authority for Energy, Networks and Environment
ATHEXClear	Athens Exchange Clearing House S.A.
BAL NC	Commission Regulation (EU) No 312/2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Networks
BCM	Balancing Capacity Market
bcm	Billion Cubic Meters
BEM	Balancing Energy Market
BM	Balancing Market
BRP	Balancing Responsible Party
BSP	Balancing Service Provider
CACM	Capacity Allocation and Congestion Management
CAM NC	Commission Regulation (EU) 2017/459 of 16 March 2017 establishing a network Code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) No 984/2013
CAPEX	Capital Expenditure
CBA	Cost-Benefit Analysis
CBCA	Cross-Border Cost Allocation
CCP	Central Counterparty
CCR	Capacity Calculation Regions
CEP	Clean Energy Package
CHP	Combined Heat and Power

CIRCABC	Communication and Information Resource Centre for Administrations, Businesses and Citizens
CNG	Compressed Natural Gas
CO_2	Carbon dioxide
COVID	Coronavirus disease
CRIDA	Complementary Regional Intra-Day Auctions
CSP	Concentrated solar power
DAM	Day-ahead market
DAPEEP S.A.	Renewable Energy Sources Operator & Guarantees of Origin S.A.
DEDA S.A	Public Gas Distribution Company S.A.
DEPA S.A.	Public Gas Corporation S.A.
DESFA S.A.	National Natural Gas System Operator S.A.
DSO	Distribution System Operator
DUoS	Distribution Use of System
EB	Electricity Balancing
EBIKEN	Association of Industrial Energy Consumers
EDA	Natural Gas Distribution Company
EEAG	European Commission Communication on State Aid Guidelines for the Environment and Energy
EED	Energy Efficiency Directive
EoI	Expression of Interest
EPA	Natural Gas Supply Company
EPBD	The Directive (EU) 2018/844 of the European Parliament and of the Council amending Directive 2010/31/EU on the energy performance of buildings and Directive 2012/27/EU on energy efficiency
ETMEAR	Special Renewable Energy Sources' Levy
EU	European Union

EU	European Union
EWRC	Energy and Water Regulatory Commission of Bulgaria
FCA	Forward Capacity Allocation
FCR	Frequency Containment Reserve
FiP	Feed in Premium
FiPC	Feed in Premium Contracts
FiT	Feed in Tariff
GCV	Gross Calorific Value
GRIT	Greece-Italy
GW	Gigawatt
GWh	Gigawatthours
HECHP	High Efficiency Combined Heat and Power
HEDN	Hellenic Electricity Distribution Network
HEDNO S.A.	Hellenic Electricity Distribution Network Operator S.A.
HENEX S.A.	Hellenic Energy Exchange S.A.
HENGAS S.A.	Hellenic Natural Gas Distribution Single Member S.A.
HHI	Herfindahl-Hirschman Index
HV	High Voltage
ICGB AD	Gas Interconnector Greece-Bulgaria AD
IDM	Intraday Market
IGB	Greece-Bulgaria Interconnector
IMF	International Monetary Fund
IP	Interconnection Point
IPTO S.A.	Independent Power Transmission Operator (IPTO S.A.)
IS	Imbalance Settlement
ISP	Integrated Scheduling Process
ITC	Inter-Transmission System Operator compensation mechanism

ITO	Independent Transmission Operator
JRC	Joint Research Centre
KOT	Residential Social Tariff
kV	Kilovolt
kWh	Kilowatthour
LIDA	Local Intraday Market
LNG	Liquid Natural Gas
LV	Low Voltage
MBP	Marginal Buy Price
MCM	Million Cubic Meters
MCV	Maximum Calorific Value
MEUR	Million Euro
mFRR	Manual Frequency Restoration Reserve
MIP	Major Importance Project
MSP	Marginal Sell Price
MV	Medium Voltage
MW	Megawatt
MWh	Megawatthour
NDP	Network Development Plan
NECP	National Energy and Climate Plan
NEMO	Nominated Electricity Market Operator
NII	Non-interconnected island
NNGS	National Natural Gas System
NNGTS	National Natural Gas Transmission System
NRA	National Regulatory Authority
OPEX	Operational Expenditure
OTC	Over the counter

OU	Ownership Unbundling
PAP	Preventive Action Plan
PCI	Project of Common Interest
PMI	Project of Mutual Interest
PPA	Power Purchase Agreement
PPC S.A.	Public Power Corporation S.A.
PSOC	Public Service Obligation Compensation
PUI	Projects of Utmost Importance
PV	Photovoltaic
RAB	Regulatory Asset Base
RAE	Regulatory Authority for Energy
RAR	Regulatory Asset Register
RCC	Regional Coordination Center
RE	Renewable Energy
RED	Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources
RES	Renewable Energy Sources
RR	Required Revenue
RSC	Regional Security Coordinator
RSP	“Readiness” Support payments
RT	Reference Tariff
RTBM	Real Time Balancing Market
S.A.	Société anonyme
SCADA	Supervisory Control and Data Acquisition System
SDDY	The coefficient for the LNG Dispersion
SDM	Charge Coefficient for reserved Transmission Capacity for each Entry/Exit Point

SDY	Coefficient of charge for reserved Regasification Capacity
SEE	South-East Europe
SEM	Commodity Charge Coefficient
SMPRES	Special Market Price for Renewables
SOGL	System Operator Guideline
SOLR	Supplier of the Last Resort
SOR	System Operation Region
SoS	Security of Supply
TAP	Trans Adriatic Pipeline
TAR NC	Regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures for gas
TMOFA	Temporary Mechanism of Optimal Forecast Accuracy
TSO	Transmission System Operator
TUoS	Transmission Use of System
TW	Terawatt
TWh	Terawatthours
TYNDP	Ten-year Network Development Plan
UGS	Underground Gas Storage
VCCGU	Variable cost of conventional Generation units
WACC	Weighted Average Cost of Capital
WAIP	Weighted-Average Import Price
ΛΓ1	Subaccount for the electricity market balance
ΛΓ2	Subaccount for RES support balance

REGULATORY AUTHORITY FOR ENERGY

132, Piraeus str., 118 54 Athens, Greece

Tel.: +302103727400

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