



REGULATORY AUTHORITY FOR ENERGY, WASTE & WATER

National Report 2024

Regulation and performance of the electricity market and the natural gas market in Greece, in 2023.

Regulatory Authority for Energy, Waste & Water (RAAEY)

Athens, June 2024.

REGULATORY AUTHORITY FOR ENERGY, WASTE & WATER

132, Piraeus str., 118 54 Athens, Greece

Tel.: +30 210 372 7400,

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

Board composition

President

Athanasios Dagoumas (since 17-7-2020)

A' Vice President

Dimitrios Psychoyios (since 17-7-2020)

B' Vice President

Dimitrios Fournalis (since 30-3-2021)

Member

Konstantinos Tsimaras (since 23-7-2020)

Member

Dimitrios Papantonis (since 30-3-2021)

Member

Stefanos Manias (since 30-3-2021)

Member

Komninos Komnios (since 30-3-2021)

Table of contents

1	FOREWORD	5
2	MAIN DEVELOPMENTS IN THE GAS AND ELECTRICITY MARKETS	6
2.1	Electricity Sector	6
2.2	Gas Sector	8
2.3	Renewable Energy Sources Sector	9
2.4	Security of Supply	10
2.5	Report on the implementation of the Clean Energy Package.....	11
2.6	EVALUATION OF MARKET DEVELOPMENT AND REGULATION IN GREECE.....	13
3	THE ELECTRICITY MARKET	14
3.1	Network regulation and technical functioning	14
3.1.1	Unbundling.....	14
3.1.2	Network extension and optimization.....	15
3.1.3	Network tariffs	17
3.1.4	Monitoring balance of supply and demand	22
3.1.5	Cross-border issues	23
3.1.6	Implementation of Network Codes and guidelines.....	25
3.2	Competition and market functioning	33
3.2.1	Wholesale markets.....	33
3.2.2	Retail market.....	43
3.2.3	Renewable energy sources and HECHP.....	65
3.2.4	Non-interconnected islands	90
4	THE GAS MARKET	100
4.1	Network regulation and technical functioning	100
4.1.1	Network and LNG access tariffs	101
4.1.2	Balancing	108
4.1.3	Cross-border issues	108
4.1.4	Gas Infrastructures.....	110
4.1.5	Implementation of Network Codes and guidelines.....	117
4.2	Competition and market functioning	117
4.2.1	Wholesale markets.....	117
4.2.2	Retail market	122
5	SECURITY OF SUPPLY	135
5.1	Security of Supply in Electricity Sector	135
5.2	Security of Supply in Natural Gas Sector	137
5.2.1	Current demand	137
5.2.2	Measures to safeguard the security of gas supply.....	137
5.2.3	Projected demand.....	139
5.2.4	Risk Groups.....	140
5.2.5	Keeping gas storage stocks in neighboring Member States.....	142
5.2.6	Solidarity Mechanism.....	142

6	<i>Lists</i>	144
6.1	List of tables	144
6.2	List of figures	146
6.3	List of abbreviations	148

1 FOREWORD

Dear Readers,

The year 2023 marked a pivotal period of transformation for the Greek Regulatory Authority for Energy (RAE). Under the newly enacted Law 5037/2023, RAE expanded its responsibilities to include waste and water regulation, leading to its renaming as the Regulatory Authority for Energy, Waste, and Water (RAAEY). This expansion also restructured the Authority's governance, increasing its Board membership to 13, comprising one President, three Vice-Presidents, and nine Board Members. Each Vice-President now oversees one of the three Boards: Energy, Water, and Waste. Members are nominated by the Ministers of Environment and Energy, Interior, and Rural Development and Food, and their appointments are confirmed following a favorable opinion from the Hellenic Parliament's Committee on Institutions and Transparency. Officially designated through a Ministerial Council Decision, the five-year terms of all 13 Members are renewable once.

The geopolitical crisis sparked by Russia's aggression towards Ukraine in 2022 continued to ripple across Europe, prompting significant national and EU-level actions to safeguard energy security in 2023. In Greece, this included updates to national legislation designed to mitigate vulnerabilities in the energy system and ensure uninterrupted energy supply. The measures addressed disruptions in natural gas imports and prioritized the diversification of energy sources, bolstered by accelerated development of renewable energy infrastructure and interconnection projects.

Throughout 2023, RAAEY remained steadfast in fulfilling its institutional mission to foster a secure, competitive, and sustainable energy market while extending its regulatory focus to encompass waste and water management. Key efforts included close monitoring of network operators' development plans, advancing market integration through the EU Target Model, and ensuring the effective implementation of RES auctions. The Authority also emphasized the protection of end consumers, particularly vulnerable groups, amidst ongoing market challenges.

Within its extended remit, RAAEY issued critical regulatory decisions, opinions, and recommendations in line with its expanded responsibilities under Energy Law 4001/2011 and its subsequent amendments. These contributions, detailed in this National Report, reflect the Authority's unwavering commitment to adapting to evolving market dynamics and addressing the broader needs of Greek society.

The President of RAAEY

Assoc. Prof. Athanasios Dagoumas

2 MAIN DEVELOPMENTS IN THE GAS AND ELECTRICITY MARKETS

2.1 Electricity Sector

A. Wholesale Electricity Market

Due to geopolitical developments and the energy crisis, Greece implemented a Temporary Mechanism for the Partial Return of Income from the Day-Ahead & Intra-Day Markets (hereinafter Temporary Mechanism) from July 8, 2022, affecting the Day-Ahead and Intraday Markets. Market participants were partially paid, with excess revenue directed to the Energy Transition Fund for the benefit of consumers. RAAEY amended the market rulebooks via Decision 604/2022 to incorporate the mechanism. Concerns arose about potential strategic scheduling of RES Operators adjusting production schedule in a way that raised concerns about balancing market abuse, prompting RAAEY to investigate and increase non-compliance fees for RES aggregators via Decision 840/2022. The temporary mechanism's duration was further extended twice within 2023, ultimately expiring on 31 December 2023.

In 2023, RAAEY continued its active role in enhancing the regulatory framework for electricity markets. Building on its longstanding collaboration with neighboring countries such as Italy, Bulgaria, and Romania, the Authority issued several key Decisions on Capacity Allocation and Congestion Management (CACM), Forward Capacity Allocation (FCA), and Electricity Balancing (BAL). These included modifications to fallback procedures and approvals for IPTO S.A.'s participation in European platforms for the exchange of balancing energy products. Between 2016 and 2023, RAAEY issued more than 110 Decisions related to the operation of Electricity Markets, addressing a wide range of critical aspects such as terms, conditions, and methodologies. These efforts reflect the Authority's commitment to fostering regional cooperation and aligning Greece's electricity market with European frameworks.

RAAEY, as the competent body for the monitoring of the wholesale electricity market, has developed and published tools on its website to ensure efficient market operation and provide comprehensive information to both consumers and market participants. These tools include data on the wholesale market's operation following the European Target Model.

B. Retail Electricity Market

In 2023, the Regulatory Authority for Energy, Waste, and Water (RAAEY) implemented measures across six key areas to regulate and monitor retail markets while protecting and empowering electricity and gas consumers during the ongoing energy crisis. These actions included:

a) Consumer Complaint Handling:

Through the MyRAE online platform, the Authority continued to process consumer complaints. This platform allows consumers to submit grievances against Suppliers and DSOs, track responses, and monitor the quality of services provided. It also supports RAAEY's role in safeguarding consumer rights and identifying areas for regulatory improvements.

b) Supplier Compliance Monitoring:

RAAEY maintained strict oversight of electricity suppliers, particularly concerning their compliance with the Electricity Supply Code regarding contract transparency and disclosures during unilateral modifications as well as their ex-ante price publications of green offers.

c) Price Comparison Tool Enhancement:

The Authority enhanced its Price Comparison Tool, enabling consumers to compare electricity and gas products more effectively. Since August 2022, prices for all available electricity products and the Universal Service tariff have been regularly posted on the RAAEY website.

d) "Positive Mentioning" Initiative:

RAAEY expanded its "Positive Mentioning" initiative, which highlights electricity suppliers meeting their financial obligations to network and RES operators. This initiative contributed to a significant reduction in overdue debts owed by suppliers to operators, positively impacting market liquidity.

e) Retail Market Oversight:

The Authority closely monitored the retail electricity and natural gas markets, addressing cases where commercial policies were not transparent or supplier offers violated regulatory standards. RAAEY issued guidelines for clear and accurate presentation of energy products on supplier websites and recommended the removal of non-compliant advertisements.

f) Policy Advisory on Transitional Arrangements:

RAAEY continued its collaboration with the Ministry of Environment and Energy to mitigate the effects of the energy price crisis, ensuring consumer protection and market stability during a challenging period.

These efforts reflect RAAEY's commitment to fostering a fair and transparent energy market while supporting consumers through regulatory interventions reinforce RAAEY's active role in ensuring a fair and transparent energy market.

C. Electricity networks

RAAEY's Decision 287/2022 involved provisions and adjustments related to specific projects outlined in the TYNDP, covering aspects such as their construction timeline and specific requirements. Noteworthy was the consideration given to proposed new international interconnection projects with Italy, Turkey, Albania and enhancement of the existing interconnection with North Macedonia. Their integration into the Hellenic Electricity Transmission System was contingent upon the submission and subsequent approval of a cost-benefit analysis (CBA) as required by Decision 590/2021. There were no new Decisions approving the TYNDP during 2023. However, RAAEY conducted a public consultation on the 2024–2033 TYNDP as submitted by the TSO, with a final decision on the plan expected in 2024 by the regulator. Detailed information about these Decisions can be accessed in chapter 3.1.2.

RAAEY's Decision 821/2022 marked the adoption of specific Key Performance Indicators (KPIs) aligned with EU Regulations of security of supply, quality and system availability. These indicators were designed to improve transparency and enhance the services provided by the TSO to other users, taking into account data provided to ENTSO-E and their impact on consumers. RAAEY had outlined calculation methods, criteria, rules, derogations and sub-cases for these indicators, while also considering practices observed in other EU Member-States. The objective of these indicators is to modernize the regulatory framework and effectively monitor TSO performance, in line with efforts to integrate RES and reduce greenhouse gas emissions, thereby ensuring the operational security of the transmission system. Within 2023, RAAEY continued to monitor the relevant KPIs, while the TSO submitted the relevant data as specified in Decision 821/2022. Detailed information about Decision 821/2022 can be accessed in chapter 3.1.2.

2.2 Gas Sector

In 2023, significant developments reshaped Greece's natural gas distribution sector. Following changes introduced by Law 4951/2022, the unbundling regime of the DSOs was reverted from ownership to legal and functional unbundling. Subsequently, on 30 September 2023, the merger of EDA Attikis and EDA Thessalonikis-Thessalias into DEPA Infrastructure was finalized, consolidating their operations. This merger marked a major structural shift, streamlining the sector under DEPA Infrastructure, now owned by Italgas Newco Srl, following its acquisition.

RAAEY Decision E-68/2023 approved the Ten-Year Network Development Plan (TYNDP) for the National Natural Gas System (NNGS) for the period 2023–2032. The TYNDP is prepared by the NNGS Transmission System Operator, DESFA S.A., in line with Article 68(2) of Law 4001/2011 and the NNGS Network Code. Its approval falls under RAAEY's jurisdiction, as outlined in Article 14 of the same law. For the 2023–2032 period, DESFA S.A. proposed a TYNDP with a total budget of €1.32 billion, allocating €476 million to new projects.

In 2023, RAAEY published three key decisions approving gas distribution network development plans for 2023–2027. Decision E-174/2023 approved a €140.95 million plan for Attica, focusing on network upgrades, new connections, and smart meter installations. Decision E-175/2023 approved a €402 million plan for seven regions and 39 municipalities, prioritizing network expansion and new connections. Distribution charges will vary, with Western Macedonia having the highest (€18.80/MWh) and Central Greece the lowest (€5.27/MWh). Decision E-176/2023 approved plans for Thessaloniki (€112.55 million) and Thessaly (€95.64 million), with slight adjustments in usage charges reflecting new investments and operational priorities. In addition, the 5-year distribution network plan of HENGAS was approved by RAAEY Decision E-105/2023 for the period 2023–2027, having a total budget of €50,614,755. For more information on the above gas-related topics, visit chapter 4.1.

Within 2023, RAAEY set the Required Revenue for Gas Transmission System and LNG Facility in Revithoussa for the Regulatory Period 2024-2027 (Decision E-69/2023). Decision E-69/2023 also set the Allowed Revenue for the Transmission System, as split between entries and exits, and LNG Facility in Revithoussa for 2024-2027. With the same decision RAAEY approved the network tariffs for the transmission system for 2024, based on DESFA's proposal in accordance with the provisions of articles 5 and 18 of the Tariff Regulation (Decision 1434/2020) and the European Regulation (EU) 2017/460.

In 2023, no new RAAEY Decisions were issued regarding Required Revenue or distribution tariffs due to DEPA Infrastructure's restructuring. Consequently, previous Decisions for the 2019–2022 period remain in effect for 2024, adjusted for inflation. For more information on tariffs and the allowed and required revenue of the operators, visit chapter 4.1.1.

In 2023, RAAEY approved key developments regarding gas transmission balancing. Under Decision E-64/2023, RAAEY approved DESFA's balancing plan for 2024, which forecasts 93% of balancing needs to be met through short-term standardized products (STSPs) and 7% through market-based balancing services via an international tender. The balancing gas requirements for 2024 are projected at 0.92% for purchasing gas and 1.29% for selling gas. Additionally, RAAEY approved the balancing cost allocation scheme and shipper charges for 2023 under Decision 229/2023. These charges and the Daily Balancing Gas Price are published on DESFA's website. More information on balancing gas, can be found at chapter 4.1.2.

Regulatory information on cross-border issues, capacity auctions, and gas infrastructure, including gas interconnectors, is detailed in Chapters 4.1.3 and 4.1.4. These sections provide insights into the regulatory framework governing cross-border gas flows, the allocation of capacity through auctions,

and the development and operation of key gas infrastructure. They also cover relevant decisions and actions taken by the regulator in relation to the integration of Greece's gas market with neighboring countries, as well as the management and optimization of gas interconnectors to enhance energy security and market efficiency.

Statistical information on gas flows, imports, exports, per country and interconnection, as well as gas prices (including import and balancing prices), is available in Chapter 4.2.1. This section provides a comprehensive overview of Greece's gas wholesale market, including cross-border flows and price trends. For retail market data, such as the number of connections, consumption patterns, suppliers, disconnections, switching, and market shares, Chapter 4.2.2 offers detailed insights. It highlights key indicators that help understand market dynamics, supplier competition, and consumer behavior within the Greek retail gas sector.

2.3 Renewable Energy Sources Sector

By the end of 2023, Greece's installed capacity of Renewable Energy Sources (RES) reached 12,040 MW, reflecting a 16.45% increase from 2022's 10,339 MW. This growth was primarily driven by the installation of 1,182 MW of new photovoltaic (PV) units. Overall, RES and HECHP production in Greece amounted to 21 TWh in 2023, up from 19.22 TWh in 2022. This rise in capacity aligns with increased investment, particularly in solar PV, and is expected to continue due to ongoing competitive tender processes and favorable economic conditions. Greece's efforts also contribute to the EU's REPowerEU plan, enhancing energy security. More information is detailed in chapter 3.2.3.1.

Law 4001/2011 assigns the RES operator, DAPEEP S.A., the responsibility to collect revenue from RES and HECHP producers to cover operational and investment costs. In 2023, DAPEEP S.A. proposed a Unit Charge for RES and HECHP Producers (UOCC) for 2024, set at 0.442 €/MWh, with a budget of €12,980,724. The estimated RES and HECHP energy production for 2024 is 23,000,000 MWh. In response, RAAEY approved the UOCC charge, reflecting increased RES electricity production, resulting in a reduced charge to producers. Visit chapter 3.2.3.2 for additional information.

In 2023, the Renewable Energy Sources (RES) market in Greece continued its growth, building on the momentum from 2022. Photovoltaic power parks saw a significant increase in installation rates, with the licensing process for photovoltaic projects growing from 63 GW to 68 GW. However, RES units with operating licenses grew more moderately, from 5,416 MW to 5,772 MW. During the year, RAAEY issued 23,499 administrative acts as part of the licensing evaluation process. More details can be found in chapter 3.2.3.3.

In 2023, energy storage facility licensing, including battery and hydro pumped storage, continued under a framework similar to that of thermal power parks, with 16 electricity production licenses granted for projects integrating storage technologies. Following the changes introduced by Law 4951/2022 in July 2022, a specialized licensing framework for standalone energy storage technologies was established. This law, along with the Electricity Production and Supply Licensing Regulation, allowed combined RES and storage licensees to transition to the new regulatory framework. A three-month window was provided for license holders to update their licenses, and unissued projects could obtain Storage Licenses. Chapter 3.2.3.4 further elaborates on the energy storage framework.

RAAEY Decision E-45/2023 established the first auction for energy storage power plants in Greece, with 93 power plants expressing interest, totaling 3,299.55 MW in output and 6,653.2 MWh in storage capacity. Decision E-130/2023 published the final list of selected plants, with 12 awarded investment aid. The total output capacity awarded was 411.79 MW, at an average price of €49,748.18/MW/year. The awarded storage capacity was 824.14 MWh. This auction, as detailed in chapter 3.2.3.5 marks a significant step in Greece's energy storage development.

In 2023, RAAEY continued to oversee the RES Levy unit charges under the regulatory framework established by Ministerial Decision ΥΠΕΝ/ΓΔΕ/76979/4917. DAPEEP S.A. forecasted a surplus for 2024, ranging from €45.67 to €267.33 million. To prevent higher consumer costs and maintain financial stability, RAAEY adopted Decision E-235/2023, keeping the unit charge for 2024 at €17/MWh. This decision ensures no deficits in the RES Special Account by estimating revenues and expenses, while maintaining a €70 million reserve for emergencies. The unit charge decision is made annually to support financial viability and protect the public interest. For more information visit chapter 3.2.3.6.

Chapter 3.2.3.7 outlines recent developments in Greece's renewable energy sector, focusing on new legislation and regulatory updates. It highlights Law 5037/2023, which modernizes Greece's energy, water, and waste management framework, expanding the responsibilities of the Regulatory Authority for Energy (RAE) to include waste and water regulation. The law aligns with EU directives on renewable energy, introduces measures to promote Citizens' Energy Communities (CECs), and supports electromobility. It also establishes rules for renewable energy integration in various sectors, grid access, and energy storage, aiming to reduce carbon emissions and ensure Greece's compliance with EU sustainability goals.

2.4 Security of Supply

In 2023, RAAEY undertook critical measures to enhance Greece's natural gas supply security. These included the fifth revision of the National Risk Assessment, examining potential risks for 2023-2026 and incorporating EU-level studies, such as Common Risk Assessments. Key scenarios simulated supply disruptions, demand variations, and exports. The revised Preventive Action Plan (PAP 2023) introduced targeted actions, including prioritizing alternative fuel plants, limiting non-essential gas use, securing supply for critical industries, modifying LNG schedules, and increasing diesel stocks. Existing measures, like interruptible consumer contracts, were also maintained. RAAEY approved the Emergency Plan 2023, detailing crisis response protocols, roles, and predefined actions, ensuring resilience across crisis levels. This plan aligns with EU Regulation 2017/1938 and includes a merit order for supply curtailments. To finance these measures, RAAEY updated the Security of Supply Levy for 2023-2027, adjusting charges per customer category to reflect evolving PAP costs. These actions demonstrate Greece's commitment to robust energy security and compliance with EU directives. For more information on these initiatives, refer to chapter 5.2.2.

In 2023, RAAEY actively contributed to regional cooperation for natural gas security through its involvement in Common Risk Assessments (CRAs). As the coordinator of the Trans-Balkan Risk Group, Greece played a key role in facilitating studies that examined the impacts of Russian gas supply disruptions, infrastructure risks, and demand reduction scenarios. Additionally, two CRAs involving Greece were finalized: the Caspian Risk Group study in August 2023, coordinated by Hungary, and the Ukraine Risk Group study in June 2023, led by Italy. These efforts reflect Greece's commitment to enhancing energy security amid ongoing geopolitical challenges. More information on these topics can be accessed in chapter 5.2.4.

There were no amendments on the existing measures to secure the electricity supply according to Regulation (EU) 2019/941, on risk-preparedness in the electricity sector within 2023.

2.5 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 published in the Official 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 (NECPs) for 2021-30. In December 2019 the 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 met its 2030 RES targets, 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 NECP¹. 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, such as hydrogen and storage.

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.

Along with the primary legislation on the reform of the licensing procedure effected by Law 4685/2020 (Gazette A' 92/2020), the Law 4951/2022 (Gazette A' 129/2022) regulates the modernization of the RES licensing process and the energy storage framework, in line with the relevant provisions set out under the recast Directive (EU) 2018/2001 of 11 December 2018 on the promotion of the use of energy from renewable source (RED). More specifically, it simplifies and accelerates the second phase of Renewable Energy Sources (RES) and High Efficiency Cogeneration Heat and Power (HECHP) projects, that commences with the submission of the application before the competent Network Operator for the granting of a Final Connection Offer and ends with the issuance of the Operating License. The main purpose of the Law 4951/2022 is to limit the maximum duration of licensing procedure to two years, as stipulated by RED II.

Towards constituting the legal framework for RES projects, the Hellenic Parliament passed, in July 2022, the Law 4964/2022 (Gazette A' 150/2022) setting out the framework for the licensing and operation of offshore wind farms in Greece. The first Greek Offshore Wind Law includes provisions concerning the development, licensing, grid connection and commercial operation of offshore wind projects in the Greek seas.

Another central development was the enactment of Law 4986/2022 (Gazette A' 204/2022) on 28.10.2022. The Law 4986/2022 transposes into the national legal framework the provisions of 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 amending Directive 2012/27/EU. By introducing the new term of the 'active consumer', the new law redefines the position of energy consumers 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

¹ <https://commission.europa.eu/system/files/2023-11/GREECE%20-%20DRAFT%20UPDATED%20NECP%202021-2030%20EL.pdf>

fundamental rights, strengthening the transparency as well as achieving greater comparability of the tariffs of electricity supply.

Finally, in order to ensure the full alignment of the Greek framework with the provisions of the Regulations 2019/943 “on the internal market for electricity” and 2019/941 “on risk-preparedness in the electricity sector”, as well as the effective application of the EU law, relevant provisions have been integrated in the Energy Law 4001/2011 and the secondary regulation (Market Codes, Grid Code etc).

2.6 EVALUATION OF MARKET DEVELOPMENT AND REGULATION IN GREECE

In 2023, Greece's energy sector demonstrated resilience and adaptability amid ongoing geopolitical tensions and the energy crisis, with the Regulatory Authority for Energy, Waste, and Water (RAAEY) developing critical regulatory and market enhancements across electricity and natural gas sectors.

In the electricity wholesale sector, the implementation and extensions of the Temporary Mechanism for the Partial Return of Income in Day-Ahead and Intraday Markets played a central role in mitigating consumer costs during the energy crisis. By channeling excess revenues into the Energy Transition Fund, RAAEY provided targeted relief for consumers, though concerns about potential market distortions and exploitation by RES aggregators required regulatory tightening, including increased non-compliance fees.

On a regional scale, RAAEY's decisions on Capacity Allocation and Congestion Management (CACM), Forward Capacity Allocation (FCA), and Electricity Balancing (BAL) reflect its commitment to aligning with European frameworks and fostering cross-border collaboration with Italy, Bulgaria, and Romania. These measures, along with over 110 market-related decisions since 2016, underscore the Authority's dedication to market efficiency and integration.

In the electricity retail sector, RAAEY continued consumer-centric initiatives such as enhancing the Price Comparison Tool and expanding the "Positive Mentioning" Initiative, which improved supplier liquidity and transparency. Platforms like MyRAE enabled streamlined complaint handling, empowering consumers during a period of price volatility. Additionally, RAAEY's oversight of supplier compliance ensured fair contract terms and accurate representation of energy products, contributing to a more competitive retail market.

The rapid expansion of Greece's Renewable Energy Sources (RES) capacity, reaching 12,040 MW, highlights robust investment in solar PV and wind energy, spurred by favorable economic conditions and tender processes. However, challenges persist, including moderate growth in operational RES units and licensing delays. The auction for energy storage plants, awarding 411.79 MW of capacity, marked a milestone in integrating storage technologies, essential for grid stability and higher RES penetration.

Structural reforms in the natural gas sector, such as the merger of EDA Attikis and EDA Thessalonikis-Thessalias into DEPA Infrastructure, streamlined operations under new ownership. RAAEY approved comprehensive network development plans for distribution and transmission, with a combined budget exceeding €1.3 billion, emphasizing network expansion and modernization. Regulatory decisions, including balancing mechanisms and updated tariffs, reinforced market stability and compliance with EU directives.

Amid heightened geopolitical risks, Greece strengthened its energy security framework through the revised National Risk Assessment, Preventive Action Plan, and Emergency Plan, which introduced robust measures for critical sectors. Greece's active role in regional risk assessments, particularly as the coordinator of the Trans-Balkan Risk Group, underscores its leadership in addressing shared energy challenges.

In conclusion, RAAEY's multifaceted approach in 2023 showcased a balance between consumer protection, market efficiency and energy transition goals. By addressing immediate crisis-driven needs while laying the groundwork for long-term sustainability, Greece's regulatory and market advancements set a strong precedent for regional cooperation and alignment with EU policies. Continued focus on licensing efficiency, infrastructure investment and transparent governance will be pivotal in maintaining this momentum.

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.) serves as the exclusive Electricity Transmission System Operator (TSO) within Greece. In 2017, IPTO S.A. underwent a transformation from the Independent Transmission Operator (ITO) model to the Ownership Unbundling (OU) model, prompted by alterations in its ownership structure. This shift saw a transition from 100% ownership by Public Power Corporation S.A. (PPC) to a diversified ownership, with 51% held by ADMIE SYMMETOCHON S.A. (Energiaki Holding), 25% by DES ADMIE S.A., and 24% by STATE GRID EUROPE LIMITED (SGID).

Initiated by IPTO's notification of its ownership change on March 1, 2017, the new certification process, in line with Article 11 of the Electricity Directive (pertaining to TSO certification in relation to third countries), was set in motion. On June 9, 2017, RAAEY issued its definitive certification decision, numbered 475/2017, after taking into careful consideration the European Commission's Opinion dated May 24, 2017, on RAAEY's preliminary certification decision (Decision 267/2017). While RAAEY imposed a series of conditions on IPTO as part of its certification, including an intricate monitoring framework, these conditions were designed to ensure that IPTO remains in compliance with unbundling prerequisites over time. This included the stipulation that any forthcoming developments, such as those concerning SGID's activities or changes in control over IPTO, be communicated to RAAEY, substantiated by rationale that upholds continued adherence to unbundling criteria, including considerations of security of supply.

Throughout 2022, RAAEY maintained vigilant oversight of IPTO's adherence to these conditions, as IPTO conducted an annual report outlining its compliance with the Electricity Directive.

3.1.1.2 *Distribution System Operators*

Presently in Greece, there exists a sole Distribution System Operator (DSO) known as the Hellenic Electricity Distribution Network Operator (HEDNO S.A. or DEDDIE S.A.). This entity is predominantly owned by PPC S.A., with a 51% stake, while the remaining 49% share was sold to Macquarie Asset Management in February 2022. HEDNO S.A. assumes the responsibilities encompassing the planning, functioning, and upkeep of the Hellenic Electricity Distribution Network (HEDN). Furthermore, HEDNO fulfills the role of the Power System and Market Operator for the Non-Interconnected Islands within the nation.

Pursuant to the relevant provisions outlined in Energy Law 4001/2011 and the European Directive 2009/72, vertically integrated utilities are compelled to uphold distinct financial records and provide separate financial statements—comprising both a Balance Sheet and a Profit & Loss Account—for each of their operations. These regulations are overseen by RAAEY, which approves the rules of accounting practices, predicated on the proposals submitted by the respective companies. RAAEY 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."

3.1.2 Network extension and optimization

In July 2020, IPTO S.A. submitted to both RAAEY and the Bulgarian Regulatory Authority EWRC a proposal for the creation of the Regional Coordination Center (RCC) for the SEE SOR Region, to replace the existing RSC SEleNeCC, as defined in article 35 of Regulation (EU) 2019/943.

RAAEY, with its Decision 117/2021 (Gazette B' 832/03.03.2021), approved TSOs' proposal to establish a Regional Coordination Center (RCC) in the Southeastern European region. In this Center the TSOs of Bulgaria, Greece and Italy will participate (ESO-EAD, IPTO S.A. and Terna SpA).

In 2022, ACER Decision 05/2022 was adopted. This Decision repealed ACER Decision 10/2020 by redefining the European System Operating Regions (SORs). Subsequently, the SEE SOR included the SEE CCR and GRIT CCR and the TSOs of Greece (IPTO S.A.), Bulgaria (ESO EAD) and Italy (Terna). Pursuant to ACER Decision 05/2022, RAAEY Decision 117/2021 had to be amended to include in the provisions establishing the SEE SOR RCC the participation of the TSO of Italy (Terna) in the RCC. In this scope, IPTO S.A. Submitted to RAAEY a new joint SEE SOR TSO proposal for the establishment of RCC in accordance with Article 35 of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 concerning the internal electricity market. Subsequently, a collaborative effort involving RAAEY, ARERA, EWRC, and a public consultation led by ANRE resulted in the final amended proposal for the establishment of the RCC in the SEE SOR. Consequently, RAAEY Decision 594/2022, outlining the amendments to Decision 117/2021 and establishing the Regional Coordination Centre (RCC) for the South-East Europe System Operation Region (SEE SOR) in accordance with Article 35 of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 concerning the internal electricity market, was published.

RAAEY, with its Decision 287/2022 (Gazette B' 4789/12.09.2022), approved the revised transmission Ten-Year Network Development Plan (TYNDP) 2022-2031, 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 characteristics. 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 RAAEY's Decision 590/2021. There were no new Decisions approving the TYNDP during 2023. However, RAAEY conducted a public consultation on the 2024–2033 TYNDP as submitted by the TSO, in October 2023, with a final decision on the plan expected in 2024 by the regulator.

DSO HEDNO S.A. held a public consultation from October 4, 2022, to October 11, 2022, regarding the preliminary Distribution Network Development Plan (DNNDP) for the period 2022-2026. Following the public consultation, HEDNO submitted the draft DNNDP to RAAEY for approval on November 22, 2022, incorporating the feedback received from the participants during the consultation. It is anticipated that RAAEY will grant its approval to the Plan in the first half of 2023 after conducting its own public consultation.

RAAEY Decision 287/2022 includes provisions and modifications related to specific projects outlined in the TYNDP, including their construction timeline and certain specifications. Notably, regarding the proposed new international interconnection initiatives with Italy, Turkey, Albania and the enhancement of the existing interconnection with North Macedonia, it is highlighted that their inclusion in the National Electricity Transmission System will be subject to approval upon submission of a Cost-Benefit Analysis (CBA), as stipulated in RAAEY's Decision 590/2021.

RAAEY with its Decision 821/2022 adopted certain KPIs based on the "security of supply" indicators arising from EU Regulations, concerning Supply Security, Quality of Supply, and System Availability. RAAEY specified the types of calculations for the indicators and established criteria, rules, derogations, and sub-cases to be taken into account in their calculation, considering the data submitted by the TSO to ENTSO-E, the impact of these indicators on consumers and broader practices followed in other Member States. To ensure the operational security of the transmission system, minimum requirements for its operation were defined. In this context, RAAEY, recognizing the need to modernize the regulatory

framework, introducing a mechanism to monitor the performance of the TSO regarding its responsibilities through the use of KPIs. Their purpose is to enhance transparency and upgrade the services provided by the Operator to System Users, while also serving the significant penetration of RES in electricity generation and reducing greenhouse emissions. Within 2023, RAAEY continued to monitor the relevant KPIs, while the TSO submitted the relevant data as specified in Decision 821/2022

3.1.3 Network tariffs

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

3.1.3.1 Transmission Network Operator – 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 following:

- 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 (RES integration and change of System's capacity curve), RAAEY deemed necessary to update the methodologies which determine the Transmission Use of System tariffs. 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 not completed in 2021, therefore tariffs 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-connected 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 (TUoS) charges, 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 Social Tariff (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.

In the process of approving the Allowed Revenue, RAAEY validates TSO's proposal based on historic performance, future trends and approved development plans (TYNDP). The Required Revenue (the Allowed Revenue adjusted with any deviations from the initial estimated amounts) is then allocated to the different consumer categories. RAAEY, with its Decision 587/2022 (later amended by Decision 946/2022) set the Allowed Revenue (AR) at 306.2 mil€ and Required Revenue (RR) for 2022 at 275.9 mil€.

<i>in thousands €</i>	2022
Allowed Revenue (AR)	306,165
Under/Over Recovery (P1)	2,878
Adjustments due to over/under investment (depreciation and allowed return) of previous years (P2)	-9,020
Revenues from Interconnection Capacity Rights (P3)	-35,676
Inter-Transmission System Operator Compensation mechanism -ITC (P4)	1,062
Revenues from Non-Regulatory Activities (P6)	2,194
Adjustments due to changes to the tax rate (P7)	12,174
Adjustments due to inflation (INF)	-7,776
EFFi	0
LDi	0
Upi	0
NCi	0
RAB HV Crete (4/48 according to Decision 643/2022)	1,487
Required Revenue 2022 (RR)	275,933

Table 1: Required Revenue of National Transmission System 2022 in real terms based on RAAEY Decision 946/2022 (amounts in €)

RAAEY with its Decision 910/2022, approved the use of the congestion income according to the Regulation 943/2019 based on the methodology of the Allowed Revenue Decision 495/2021 for the year 2022. Decision 910/2022 approved the utilization of the sum of €68,674,943.39 from the L-E IPTO Account named "Interconnection Rights Revenue" as stipulated in section 11.11 of the Transmission System Code, aimed at reducing the transmission system charges; the allocation of €6,530,996.83 to an internal account of IPTO S.A., in accordance with the regulations, for the completion of the interconnection transmission line project between Greece and Bulgaria "Nea Santa-Maritsa" within 2023; and the allocation of €600,000 to an internal account of IPTO S.A., following the provisions of Regulation (EU) 943/2019, intended for the interconnection transmission line project between Greece and Turkey.

The key financial figures of IPTO in the last 5 years (actual amounts for 2018-2022), according to annual financial statements and RAAEY Decisions for the approval of the Required and Allowed Revenue are the following:

<i>in mil €</i>	2018	2019	2020	2021	2022
Revenues from Use of System Charges	194.9	229.1	273.6	270.36	271.96
Net Revenues before tax	108.9	134.8	122.1	88.99	89.17
Approved Allowed Revenue of Transmission System	233.9	252.4	281	285.9	306.2
Approved Required Revenue of Transmission System	197.5	198.9	198.5	211.6	275.9

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

In the following table, the Transmission System user tariffs based on the Required Revenue of 2022 (RAAEY Decision 587/2021) are shown, based on IPTO's proposal. Those charges have been applied since 1st September 2022 based on Decision 643/2022.

Consumers Category	Capacity charge	Energy charge (cents €/ kWh)
Large Consumers HV	3,122 €/MW / month	-
Consumers MV	3,240 €/MW / month	-
Households LV	-	0.844
<i>*This category includes street and square lighting</i>		

Table 3: Regulated Tariffs applied for the use of the transmission system in 2022 (Decision 643/2022).

The Weighted Average Cost of Capital (WACC) parameters were thoroughly analyzed in compliance with Article 16 of the Tariffs' Methodology. RAAEY carefully considered vital market indicators and data repositories, 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.

	2022	2023	2024	2025
Risk-free rate	0.5%	0.5%	0.5%	0.5%
Market Risk Premium	5.50%	5.50%	5.50%	5.50%
Gearing ratio (loan)	39.0%	39.0%	39.0%	39.0%
Equity Beta	0.8	0.8	0.8	0.8
Equity Return	4.9%	4.9%	4.9%	4.9%
Country Risk Premium	1.5%	1.5%	1.5%	1.5%
Cost of equity (post-tax)	6.4%	6.4%	6.4%	6.4%
Tax rate	22%	22%	22%	22%
Cost of equity (pre-tax)	8.21%	8.21%	8.21%	8.21%
Debt rate	2.8%	2.8%	2.8%	2.8%
Total WACC (nominal, pre-tax)	6.10%	6.10%	6.10%	6.10%

Table 4: Main parameters of WACC- IPTO S.A. - 2022-2025 (Decision 587/2022)

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 RAAEY 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) was introduced, commencing from the 1st Regulatory Period (2021-2024), 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 HEDNO for the reduction of Network energy losses and the improvement of Distribution service quality were considered. Another significant methodological matter that was considered in the Methodology 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 RAAEY's Decision 1431/2020, is applied on a transitional basis, the previous methodology, prescribed in RAAEY's Decision 840/2012, remains in force.

RAAEY, with its Decision 632/2021, approved the Allowed Revenue, while Decision 868/2021 approved the Required Revenue of the Distribution Network Operator for 2022. The Allowed Revenue was set at 781.9 million € (2021: 776 million €) and the Required Revenue at 797.9 million € (2021: 777.3 million €). Furthermore, RAAEY 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.

<i>in thousands of €</i>	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 5: Allowed Revenue 2021-2024 for HEDNO S.A.

The key financial figures of HEDNO in the last 5 years (2018-2022), according to annual financial statements and RAAEY Decisions for the approval of the Required and Allowed Revenue are the following:

<i>in mil €</i>	2018	2019	2020	2021	2022
Revenues from Use of Network Charges	711.1	727.8	710.8	727.1	703.2
Net Revenues before tax	-17.82 ³	99.4	26.03	19.12	25.53
Approved Allowed Revenue of Distribution System	743.6	753.4	758	776	781.9
Approved Required Revenue of Distribution System	752.8	743.6	751.4	777.3	797.9

Table 6: Key financial figures of HEDNO S.A.

The Required Revenue of the distribution network 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 System (DUoS) code, consumers are classified based on their connection voltage and metering capabilities. More specifically, consumers

³ Financial Statements DEDDIE 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).

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.

RAAEY Decision 2/2020 approved the tariffs of Distribution Network that are applied since 1st April 2020:

	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)

Consumers Category	Capacity Charge	Energy charge (cents €/kWh)
Consumers MV	1,097 €/MW Peak Demand /month	0.28
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	1.73
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	1.9
Consumers LV	0.52 €/kVA subscribed capacity, charged per year	2.13
Consumers (vulnerable consumers)	-	2.37
Others LV (maximum 25 kVA)	1.46 €/kVA subscribed capacity, charged per year	1.9

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

3.1.4 Monitoring balance of supply and demand

RAAEY, in the context of its responsibilities to monitor the energy markets (Article 22 of Law 4001/2011) and in particular in the context of monitoring the conduction of activities and the compliance with suppliers' license 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 on supply and distribution activities of electricity and gas retail energy markets. RAAEY collects periodically data from 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, RAAEY, within 2018 started developing 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 at the end of 2019 accompanied by the relevant letters and usage manuals which were shared with the Suppliers and 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 checked and its main strengths and weaknesses were designated.

3.1.5 Cross-border issues

3.1.5.1 *Second Interconnection between Greece and Bulgaria*

The project involves the development of a second interconnection line between the systems of Greece and Bulgaria. This will be achieved through a 400 kV overhead interconnection between the N. Sanda substation and the Maritsa East 1 substation. The line will be designed to carry a nominal capacity of 2,000 MVA and will span a total length of approximately 151 km. Of this length, around 30 km will be situated within Greek territory, while approximately 121 km will fall within Bulgarian territory.

The new 400 kV Greece-Bulgaria interconnector is considered a project of major pan-European significance. It is projected to become integrated into the European System in early 2023. This undertaking has been included in the Ten-Year Development Plan (TYNDP) of ENTSO-E since 2012. It forms part of cluster 142:CSE4, which encompasses three additional 400 kV transmission lines within Bulgarian territory, all centered around the Maritsa East 1 substation.

This interconnector also serves as a fundamental component of the NSI East Electricity Priority Corridor (North-South electricity interconnections in Central Eastern and Southeastern Europe) since 2013. It functions as an integral segment of the broader corresponding cluster related to the PCI 3.7 projects.

The construction of the second interconnector between Greece and Bulgaria is anticipated to increase the transmission capacity at the border of the two nations to 800 MW in the Greece-to-Bulgaria direction and 1,350 MW in the Bulgaria-to-Greece direction. Within this context, the project will contribute to managing the increased power flows in the North-South direction of the Balkan Peninsula, bolstering the adequacy margin, and facilitating the further deployment of renewable energy power parks in the northern region of the country. Simultaneously, it will fortify the European transmission system along the eastern border, an area characterized by limited presence of the 400 kV system and relatively weak connections to the large-scale system in Turkey (one interconnector with Greece and two with Bulgaria). This effort will play a role in integrating the electricity markets of Europe and Turkey.

IPTO S.A. and the Bulgarian Operator (ESO-EAD) secured funding for project studies as part of PCI 3.7.1 through the Connecting Europe Facility (CEF), and these studies were successfully concluded. The project has now reached sufficient maturity to commence implementation, having obtained the necessary permits from both sides.

In line with its status as a PCI project, the Investment Request was jointly submitted with the Bulgarian side to the Regulatory Authorities of the two countries (EWRC-Bulgaria and RAAEY-Greece) in March 2018. Subsequently, in August 2018, the Regulatory Authorities issued the Cross-Border Cost Allocation (CBCA) decision between the two countries. In October 2018, an application for funding the project's construction through the CEF was jointly submitted with the Bulgarian side. While 50% of the financing for the project's construction was secured on the Bulgarian side—proportionate to its larger portion of the route (121 out of 151 km)—the project cost for the Bulgarian side constitutes a significant part (40%) of Bulgaria's 10-year investment plan for electricity transmission projects.

For the Greek side, the financing was not approved by the CEF mainly due to the lower implementation cost of the project within Greek territory. Consequently, this investment represents a smaller share of the overall investment program for electricity transmission projects and is expected to have a minor impact on the Use of System Charges following its implementation. It is important to note that for the construction cost of the segment within Greek territory, the congestion income generated from the allocation of access rights to international interconnections of the country, as defined in Decision 425/2015, will be utilized. This income covers roughly half of the construction costs on the Greek side.

3.1.5.2 *Second interconnection between Greece and Italy*

Based on the results of studies investigating the requirements for enhancing the European Transmission Network, it has been determined that achieving price convergence between Greece and Italy necessitates a bolstering of the electrical interconnection between them. With this objective in mind, collaborative procedures were initiated in November 2020 between IPTO S.A. and the Italian TSO TERNA, marked by the establishment of a working group tasked with conducting studies to reinforce the interconnection of their respective electricity systems.

Within the framework of this cooperation, various options for the development of a new submarine interconnection between the Greek and Italian systems will be thoroughly examined in the coming period. Furthermore, the potential of utilizing the existing infrastructure of the SP Greece-Italy interconnection, which has been operational since 2002, will also be explored.

As per current estimations, the demand for reinforcement in terms of new interconnection capacity falls within the range of 500 – 1,000 MW.

3.1.5.3 Greece – Cyprus – Israel Interconnection (EUROASIA Interconnector)

The project pertains to the implementation of an interconnection between the transmission systems of Greece-Cyprus and Israel through direct current interconnectors, was scheduled for completion in 2023. Following the inclusion of the Greek State in the new list of Projects of Common European Interest (PCI) as published⁴, the "EUROASIA Interconnector" project encompasses the segments 3.10.1, which involves the Israel-Cyprus interconnection, and 3.10.2, corresponding to the Cyprus-Greece (Crete) interconnection, both linked by DC connections.

It is noteworthy that the portion involving the Attica-Crete interconnection, which was previously included within the aforementioned PCI designation, has been subsequently excluded. This specific portion will now be carried out by the dedicated entity "ARIADNI INTERCONNECTION S.A.," ensuring the incorporation of appropriate specifications to guarantee the interoperability of the Attica-Crete interconnection with the interconnections to Cyprus and subsequently to Israel.

3.1.5.4 Greece – North Macedonia Interconnection upgrade

As part of ENTSO-E's 2018 Trans-European Ten-Year Development Plan (TYNDP), studies were conducted to assess the requirements for strengthening the European Transmission Network, with a projection extending to 2040. These studies recognized the need to increase the electricity transmission capacity between the Greek and North Macedonian systems.

The solution proposed by IPTO S.A. and the North Macedonian TSO (MEPSO) to address this imperative was the enhancement of the 400 kV Meliti - Bitola interconnector. This initiative was incorporated into the TYNDP 2018 as a project deserving consideration, with an intended implementation period post-2030. The same project was subsequently re-submitted for consideration in the 2020 TYNDP, and its feasibility is set to be explored through a collaborative working group comprising members from both IPTO and MEPSO, established for this precise purpose.

⁴ Refer to https://energy.ec.europa.eu/publications/annex-delegated-regulation-establishing-eus-4th-pci-list-other-languages_en.

3.1.5.5 *Second Greece – Turkey Interconnection*

A joint working group between the TSOs of Greece, Bulgaria and Turkey (IPTO, ESO-EAD & TEIAS) was established in a previous period to explore alternative scenarios for the development of new interconnections between the European and Turkish Systems to increase the transmission capacity at the Greece-Turkey and Bulgaria-Turkey borders.

The joint studies that have been completed have demonstrated the potential for future interconnectors between the European and Turkish Systems, which would be able to contribute to increasing transport capacity and, in addition, to strengthening the systems on this border.

In a tripartite meeting held in Izmir between IPTO, ESO-EAD & TEIAS it was decided to submit a new project entitled "EAST BALKAN CORRIDOR" to the ENTSO-E's Pan-European Ten-Year Development Programme (TYNDP). The projects, a new 400 kV Greece-Turkey interconnector and a new 400 kV Bulgaria-Turkey interconnector were submitted as projects under consideration in TYNDP 2020, and the results of the TYNDP 2020 assessment confirmed the need to increase the transmission capacity between these countries.

3.1.5.6 *Second Interconnection between Greece and Albania*

In April 2020, IPTO S.A. initiated a collaboration with the Albanian TSO (OST) to assess the feasibility of establishing a fresh interconnection line connecting Greece and Albania. These discussions are currently in their preliminary phase and primarily revolve around the examination of technical, economic, and other pertinent factors for devising a new interconnector operating at 400 kV. The aim is to link the southern transmission system of the neighboring nation with a suitable Extra High Voltage Center within the Greek transmission system.

3.1.6 Implementation of Network Codes and guidelines

(A) In 2023, RAAEY, within the framework of Regulation (EU) 2015/1222 concerning the capacity allocation guidelines and congestion management (CACM), published the following Decisions:

1. [Decision E-137](#) - Amendment of the Coordinated Capacity Calculation Methodology within the Southeast Europe Capacity Calculation Region (SEE CCR), in accordance with Articles 20 and 21 of Commission Regulation (EU) 2015/1222, dated July 24, 2015, establishing a guideline on capacity allocation and congestion management

Following Decision 121/2021 (B' 1036) by RAAEY, which approved the proposal by the Transmission System Operators of the Southeast Europe Capacity Calculation Region (SEE CCR) for the coordinated capacity calculation methodology within the region, a revised joint proposal on the methodology was resubmitted by the TSOs to the Regulatory Authorities of the SEE CCR.

The TSOs of the SEE CCR amended the coordinated capacity calculation methodology of the region to integrate, first, the provisions of Article 16 of Regulation (EU) 2019/943, setting out the requirements for achieving the minimum capacity target for cross-zonal trade, and second, provisions to include TSOs from third countries (non-EU members) as technical counterparties, in line with the guidelines issued by the European Commission's Directorate-General for Energy (DG Energy) to ACER and ENTSO-e.

Specifically, the amended methodology considers the effective network structure and the borders between the SEE CCR and third countries, with an emphasis on the establishment of agreements between TSOs for including third countries as technical counterparties. Accordingly, the methodology

will apply to TSOs of third countries, provided they sign an agreement with all TSOs of the SEE CCR, in which they commit to the methodology and accept all associated rights and obligations.

Additionally, to comply with Article 16(8) of Regulation (EU) 2019/943, the TSOs of the SEE CCR introduced amendments to the methodology for monitoring the available margin for cross-border trade when calculating capacity for the Day-Ahead Market timeframe. The Coordinated Capacity Calculation (CCC) competent body will ensure that the calculated capacity meets minimum capacity requirements as outlined in Article 16(8) of Regulation (EU) 2019/943, using remedial actions allocated for this purpose by the TSOs of the SEE CCR or as proposed by the CCC competent body.

Subsequently, the National Regulatory Authorities of the SEE CCR unanimously decided to approve the amended coordinated capacity calculation methodology within the region, in accordance with Articles 20 and 21 of the Regulation.

(B) In 2023, RAAEY, within the framework of Regulation (EU) 2017/2195 concerning the establishing of a guideline on electricity balancing (EBGL), published the following Decisions:

1. [Decision E-46](#) - Approval of the Joint Proposal by Transmission System Operators (TSOs) of the Greece-Italy Capacity Calculation Region (CCR GRIT) for the Methodology for Calculating Cross-Zonal Capacity within the Balancing Timeframe for the Exchange of Balancing Energy or the Application of the Imbalance Calculation Process, in accordance with Article 37 of Regulation (EU) 2017/2195 of the Commission, dated November 23, 2017, on establishing a guideline on electricity balancing.

In accordance with Article 37, paragraph 3 of Regulation (EU) 2017/2195, within 5 years of the Regulation's entry into force, all TSOs within a capacity calculation region must establish a methodology for calculating cross-zonal capacity within the balancing timeframe for the exchange of balancing energy or for applying the imbalance calculation process. This methodology aligns with the cross-zonal capacity calculation methodology applied within the intraday market timeframe as defined by Regulation (EU) 2015/1222.

In this context, the responsible TSOs of the Greece-Italy Capacity Calculation Region (GRIT CCR) submitted a final joint proposal on the methodology for calculating cross-zonal capacity within the balancing timeframe to the National Regulatory Authorities of GRIT CCR. This proposal was subjected to a public consultation by RAAEY from January 10, 2023, to January 31, 2023.

Subsequently, the National Regulatory Authorities of the GRIT CCR evaluated the TSOs' proposal in terms of its compliance with Regulation requirements. The authorities jointly concluded that the final proposal for the methodology for calculating cross-zonal capacity within the balancing timeframe for the exchange of balancing energy or for applying the imbalance calculation process demonstrated improved content, incorporating the recommendations from the Regulatory Authorities, and they unanimously decided to approve the TSOs' joint proposal.

2. [Decision E-185](#) - Amendment of the Joint Proposal by the Transmission System Operators of the Southeast Europe Capacity Calculation Region (CCR SEE) for the Methodology on Cross-Zonal Capacity Calculation within the Balancing Timeframe for the Exchange of Balancing Energy or the Application of the Imbalance Calculation Process, in accordance with Article 37 of Commission Regulation (EU) 2017/2195, dated November 23, 2017, on establishing a guideline on electricity balancing

According to Article 37, paragraph 3 of Regulation (EU) 2017/2195, within 5 years of the Regulation's enactment, all TSOs within a capacity calculation region must develop a cross-zonal capacity calculation methodology within the balancing timeframe for the exchange of balancing energy or the implementation of the imbalance calculation process. This methodology is designed to prevent market distortions and is consistent with the cross-zonal capacity calculation methodology applied within the intraday market timeframe as defined by Regulation (EU) 2015/1222. To comply with this provision, a

joint proposal for the above methodology was submitted to the Regulatory Authorities of the SEE CCR by the relevant TSOs.

Subsequently, the Regulatory Authorities of the SEE CCR unanimously agreed to amend the aforementioned joint TSO proposal, specifically focusing on further refinement and enrichment of the text. This includes the appropriate introduction of the detailed methodologies required by the Regulation for the calculation of input data, as well as enhancements to the primary cross-zonal capacity calculation methodology, moving references from explanatory notes into the core methodology, and improving the phrasing.

(C) In 2023, RAAEY, within the framework of Regulation (EU) 2017/1485 concerning the establishment of a guideline on electricity transmission system operation (SOGL), published the following Decisions:

1. Decision E-82/2023: "Taking appropriate steps to approve the proposal for setting the minimum activation time for Frequency Containment Reserve (FCR) required to ensure that units or groups providing FCR with limited-energy reservoirs remain available during alert situations, in accordance with Article 5(9) of Regulation (EU) 2017/1485."

As provided in Article 6(3)(d)(v) and Articles 156(9) and 156(10) of Regulation (EU) 2017/1485, IPTO submitted to RAAEY in December 2021 a joint proposal from TSOs of the Continental Europe synchronous area on determining the minimum activation time for FCR from units or groups providing FCR with limited-energy reservoirs during alert situations.

This proposal sets a minimum activation time of 30 minutes for all FCR providers (with limited-energy reservoirs) selected after a period of 24 months following the implementation of the methodology. For FCR providers (with limited-energy reservoirs) selected within or prior to this 24-month period, the activation time remains at the duration for which they were preselected, with a minimum of 15 minutes.

The Continental European TSOs failed to submit a new proposal within the prescribed time frame of 2 months stipulated by Article 7(1) of Regulation 2017/1485. Instead, they communicated a roadmap with timelines to the Regulatory Authorities for meeting the requirements of the modification request. Therefore, in line with Article 5(9) of the Regulation, the Regulatory Authorities are jointly required to take appropriate steps to approve the TSO proposal.

By Decision No. E-10/2023, RAAEY informed IPTO of the "appropriate steps" jointly agreed upon by the Regulatory Authorities of Continental Europe to approve the proposal for determining the minimum activation time for Frequency Containment Reserve (FCR) from units or groups providing FCR with limited-energy reservoirs during alert states, as specified in Article 156(10) of Regulation (EU) 2017/1485.

2. [Decision E-192/2023](#): "Approval of the Training Program and Certification Process for personnel responsible for the real-time operation of the Electricity Transmission System, operational planning, and balancing market, in accordance with Articles 58 to 63 of Regulation (EU) 2017/1485"

According to Title 4 (Articles 58-63) of Regulation (EU) 2017/1485, each TSO must develop a training program for its personnel, specifically:

- An initial training program for certification and a continuous training program for employees responsible for the real-time operation of the transmission system.
- A training program for employees responsible for operational planning. Each TSO is also required to contribute to the development and approval of training programs for personnel of the relevant regional security coordinators.
- A training program for employees responsible for balancing.

In July 2022, IPTO S.A. initially submitted the "Training Program and Certification Process for personnel responsible for the operation of the Transmission System, operational planning, and balancing market" to RAAEY for approval, in compliance with Articles 58-63 of Regulation (EU) 2017/1485. Following an evaluation by RAAEY, amendments were requested to ensure full compliance with the Regulation. IPTO then submitted a revised proposal in July 2023, which, after public consultation, was approved by this specific Decision of RAAEY.

This Decision establishes rules regarding:

- Theoretical and practical training of personnel responsible for real-time system operations.
- Training of personnel responsible for operational planning.
- Training of personnel responsible for the balancing market.
- The role and responsibilities of the Training Coordinator.
- The certification process for employees responsible for real-time operation and the validity period of certification.
- Maintaining records of trainers, evaluation records, issued certificates, and records of each employee's training program content.
- The duration and frequency of training programs.

This structured approach ensures that the personnel involved in critical operations are well-trained and certified, with transparent and standardized processes aligned with EU regulatory requirements.

(D) In 2023, RAAEY published the following Decisions:

1. [Decision E-1](#) - Approval of a deviation from the minimum level of available cross-zonal capacity for Greece - Bulgaria border for the year 2023, as provided for in paragraphs 8 and 9 of Article 16 of Regulation (EU) 2019/943 of the European Parliament and of the Council, of 5 June 2019, on the internal electricity market

In February 2023, IPTO S.A. submitted a request to RAAEY for the approval of a deviation from the minimum level of available cross-zonal capacity for Greece - Bulgaria border for the year 2023, as provided for in paragraph 8 of Article 16 and in accordance with paragraph 9 of the same article of the Regulation (EU) 2019/943.

IPTO S.A. informed RAAEY that it cannot comply with the minimum level of available capacity, as set out in par. 8 of Article 16 of Regulation (EU) 2019/943, for the said border for the year 2023, and provided reasons related to operational security to support its request.

In particular, the application of the minimum capacity of 70% provided for in paragraph 8 of Article 16 of Regulation (EU) 2019/943 for borders using an approach based on the coordinated net transmission capacity jeopardizes operational security for the following reasons:

1. Lack of consideration of flows from third countries in the calculation of capacity and available margin for cross-zonal transactions
2. Insufficient reallocation capability to ensure the 70% capacity criterion
3. Insufficient IT tools to calculate and validate capacity (according to Regulation (EU) 2019/943)

For the above reasons which support the necessity of deviating from the application of the minimum margin available for cross-zonal transactions, IPTO S.A. requested that it be granted for 1 year, in order to implement the approved necessary methodologies and practices for the calculation of coordinated cross-zonal capacity for day-ahead and intraday zones in the South-East Europe Capacity Calculation Region (SEE CCR), to conclude an agreement with third countries and to integrate the flows from them in the relevant methodologies, calculations and procedures.

In accordance with the requirement of paragraph 9 of Article 16 of Regulation (EU) 2019/943, RAAEY consulted the request of IPTO S.A. with the Regulatory Authorities of other member states within the framework of the ACER's All Regulatory Authorities' Working Group (ARA WG), as a collective body of the Regulatory Authorities, from 01.02.2023 to 22.02.2023 and no National Regulatory Authority expressed disagreement.

2. [Decision E-209](#) - Approval of the Capacity Allocation Rules at the Bidding Zone Borders between Greece and non-EU countries (Albania, North Macedonia, and Turkey) for the Year 2024, in accordance with Provisions 7.8 and 7.11 of the Transmission System Operation Code

According to sections 7.8 and 7.11 of the Transmission System Operation Code and in relation to the allocation of long-term and short-term (Day-Ahead) capacity at the Greek bidding zone borders with non-EU countries (Albania, North Macedonia, and Turkey), it is provided that allocation takes place through explicit auctions conducted by the Coordinated Auction Office in Southeast Europe (SEE CAO). Furthermore, the procedure and operations are governed by the Capacity Allocation Rules and their annexes.

Through Decision 863/2022, RAAEY approved the amendment of "the rules for the conduct of auction procedures for the long-term and short-term allocation of physical transmission rights (PTRs) for electricity imports and exports via the interconnection lines between the Greek System and the Systems of Albania, North Macedonia, and Turkey" for 2023, as detailed in the Auction Rules documents submitted by the Operator.

In fulfilling its responsibilities, IPTO S.A. submitted a recommendation for the approval of the Capacity Allocation Rules at the Bidding Zone Borders between Greece and non-EU countries, which SEE CAO is to implement for 2024 and beyond. The content did not differ from the Auction Rules text for long-term and day-ahead capacity allocation, as approved for 2023 by the aforementioned RAAEY Decision.

RAAEY, considering the TSO's recommendation and the fact that implicit day-ahead auctions as described in Regulation (EU) No. 2015/1222 of July 24, 2015, do not apply to the bidding zone borders between Greece and non-EU countries, determined that the SEE CAO would continue to conduct explicit day-ahead auctions in 2024, according to the Auction Rules for Day-Ahead capacity allocation. Therefore, it was deemed reasonable to extend the validity of the Capacity Allocation Rules, as detailed in the submitted Auction Rules documents and previously approved under Decision No. 863/2022 by RAAEY, through December 31, 2024.

3. [Decision E-235](#) - Setting the Base Charge of Article 143, paragraph 3b, of Law 4001/2011, as currently applicable, for the Calendar Year 2024

According to paragraphs 3 and 4, section b of Article 143 of Law 4001/2011, revenue for the Sub-Account for Support of Existing RES and High-Efficiency Cogeneration (HECHP) projects connected to the interconnected system before January 1, 2021, and the Sub-Account for Support in the Special Account for RES and HECHP in Non-Interconnected Islands (NII) includes, among others, revenue from the RES Levy (ETMEAR) applied to electricity consumption. The charges for this levy are determined by a RAAEY Decision each December for implementation in the following calendar year. This process aims to ensure no deficits by estimating the expected revenues and expenses of the national RES Special Account, while maintaining a reserve of €70 million for emergency expenses.

Since January 1, 2019, a single ETMEAR charge has been applied to all consumer categories, with specific exceptions, for electricity consumed from the Network or System. This is called the "Base Charge." For 2019 and 2020, this Base Charge (BC) was set by Decision of the Minister of Environment and Energy, and since 2021, it has been determined by RAAEY.

In carrying out its responsibilities to set the 2024 Base Charge, RAAEY, considering a projected deficit of €222.22 million (excluding the €70 million reserve) in the RES Special Account by the end of 2023 as published by DAPEEP S.A. on July 18, 2023, requested updated data from DAPEEP, including: (a) recent revenue and expense data for the RES Special Account for 2023 and forecasts for 2024; (b) detailed data for determining the Base Charge per Article 18 of Ministerial Decision YPEN/DHE/74949/926, particularly regarding any reduced ETMEAR charges, and an update on the timeline for completing ETMEAR settlements for reduced charges for 2019 and subsequent years; (c) impact assessments

related to the potential expiration of the Temporary Mechanism for Partial Recovery of Day-Ahead Market Revenue on RES Special Account revenues; and data on the Energy Transition Fund's inflows and outflows.

DAPEEP S.A., in response to RAAEY's request, provided detailed data and projections for total inflows and outflows, calculations and balance projections for the RES Special Account through 2023 and 2024. According to this data and considering approximately €100 million in revenue from the Green Levy on diesel fuel (per Decision YPEN/GDE/131390/7540 by the Deputy Ministers of National Economy and Environment & Energy), the accumulated balance of the RES Special Account is expected to be -€96.74 million by the end of 2023. Based on various scenarios, the RES Special Account balance for 2024 is projected to be surplus, ranging between €45.67 million and €267.33 million, depending on the average Day-Ahead Market Clearing Price in 2024. This projection includes €216.82 million in revenue expected in 2024 from settling reduced ETMEAR charges for 2019–2021.

Accordingly, the Authority deemed it appropriate to maintain the ETMEAR Base Charge for 2024 at €17/MWh, as previously set in Decision YPEN/GDE/76979/4917 (Gazette B' 3373/31.08.2019) for 2019 and 2020, and in RAAEY Decisions 1654/2020, 1063/2021, and 931/2022 for 2021, 2022, and 2023, respectively, as the RES Special Account's sustainability is not at risk. However, RAAEY requested that DAPEEP promptly conclude all outstanding retroactive settlements related to reduced ETMEAR charges, anticipated to bring approximately €216 million to the Special Account, thus ensuring balance by year-end 2024.

Additionally, as the estimates do not guarantee the maintenance of the €70 million reserve, RAAEY decided to recommend to the Minister and Deputy Minister of Environment and Energy, under its mandate in Articles 30 and 143 of Law 4001/2011, that in 2024, a minimum of 10% of revenue from greenhouse gas emission rights auctions be allocated to the Special Account under Article 143 of Law 4001/2011, thereby ensuring its stability and functionality without additional consumer charges.

Finally, RAAEY decided to recommend amending Article 143 of Law 4001/2011 to include the option of revising the Base Charge mid-year, effective from July 1 to December 31, if necessary, based on the in-year revenue and expense trends for the Special Account.

4. [Decision 198/2023](#): "Determination of the Electricity Distribution Network Tariffs."

Through Decision 198/2023, RAAEY approved the Distribution Network tariffs, which aim to recover the Required Revenue of the Operator for 2023 (RAAEY Decision No. 164/2023). This also includes the estimated under-recovery for the first quarter of 2023 due to previously set charges that were lower.

This Decision implements, for the first time, the calculation methodology outlined in the Network Tariffs Manual of the Distribution Network Operation Code (RAAEY Decision No. 707A/2021). According to the Manual, consumer categories were established based on voltage level and further divided by usage category and the type of meter used.

5. [Decision E-21/2023](#): "Amendment and codification of the Transmission System Tariffs Manual of the Electricity Transmission System Operation Code into a single text."

Following a request from the TSO and further proposals by the Distribution Network Operator, RAAEY issued Decision E-21/2023 amending the Transmission System Tariffs Manual of the Electricity Transmission System Operation Code (RAAEY Decision No. 1001/2021) to address the following issues:

- i. Issues arising in cases where, during a single month, a connection point is not continuously represented by the same Supplier, or the purpose of the connection's tariffs along with the corresponding unit tariff, or the consumer using the connection changes, as identified in the DSO's systems by their Tax ID Number.
- ii. Calculating the System tariff discount for medium-voltage consumers, specifically defining the reference period for determining the applicable discount rate. This is based on consumption criteria

and the consumer's load factor, set as the 2 years preceding the year in which unit charges are calculated.

The amendments introduced by this Decision address:

- i. The introduction of the concept of a "Billing Period," defined as the period within a month during which a connection point is continuously represented by the same Supplier, without any change in usage purpose or consumer (identified by Tax ID Number).
- ii. The System Tariff for medium- and low-voltage consumers will be calculated independently for each Billing Period.
- iii. Determining the discount rate applicable to a medium-voltage consumer, based on their consumption and load factor during the Billing Period, compared to their average annual consumption and load factor over the previous 2 years.

6. [Decision E-70/2023](#): "Amendment of the Manual for Meter Representation and Periodic Settlement regarding the calculation of energy allocated to Suppliers for customers with net-metering contracts and other issues."

RAAEY, under its responsibilities defined in Article 128(1) of Law 4001/2011 and Articles 2 and 3 of the Distribution Network Operation Code, received proposals from Suppliers to amend provisions in the Manual for Meter Representation and Periodic Settlement of the Distribution Network Operation Code (Gazette B'4737/2020).

Specifically, the proposals concern amendments to Article 19, par. 1 of the Manual related to calculating energy allocated to Suppliers per Settlement Period for Deviation for their customers with bidirectional Telemetry Load Meters. For these customers, both Injected and Absorbed energy are metered and cleared at the meter level (e.g., energy from self-generation systems with net-metering).

Suppliers proposed that the absorbed energy allocated to Suppliers per Settlement Period could have a negative value if the injected energy exceeds the absorbed energy during the same Deviation Settlement Period. To justify their proposal, Suppliers noted that, under the current provisions of Article 19, par. 1, when injected energy from customers participating in a net-metering scheme exceeds absorbed energy, Suppliers are billed for larger quantities than they ultimately invoice their customers under the net-metering contract. This is because, for invoicing, the total injected energy is considered, which reduces the total absorbed energy during the same settlement period. Furthermore, Suppliers requested corrective settlements for previous periods, considering any negative difference between absorbed and injected energy per Deviation Settlement Period.

During the public consultation held by RAAEY, no objections were raised regarding the proposed amendments to Articles 15 and 19 of the Manual. However, the Operators highlighted the need for a transitional period to adapt their systems, enabling the necessary calculations and the execution of Balancing Market Settlements under the new rules.

Therefore, RAAEY deemed the Supplier-proposed amendments reasonable and approved them. A 3-month transitional period was established for implementing the necessary technical adjustments, during which interim and corrective settlements will be conducted according to the existing methodology. Additionally, RAAEY approved other amendments to the Manual suggested by the DSO, affecting Articles 10, 21, and 24 of the Manual.

7. [Decision E-94/2023](#): "Amendment of the Balancing Market Regulation (B' 985/2022) in accordance with Articles 17 and 18 of Law 4425/2016, and the Transmission System Operation Code (B' 4658/2020), in accordance with Article 96 of Law 4001/2011"

Pursuant to Articles 135 and 136 of Law 4001/2011, as amended, RAAEY issued Opinion 13/2022 to the Minister of Environment and Energy, which led to Ministerial Decisions establishing the "Licensing Regulation for Ownership and Operation of Direct Lines." These Decisions set the terms, conditions, and licensing procedure for Direct Lines. In response to these Ministerial Decisions and to complete the regulatory framework for the operation of Direct Lines, IPTO S.A. submitted a proposal to RAAEY for amendments to the Balancing Market Regulation (BMR) and the Transmission System Operation Code.

Specifically, regarding the BMR amendment, new definitions and provisions were introduced for calculating the Electricity Supply Quantity via Direct Lines, exempting Direct Line Users with Parallel Connections from charges to the Transmission System Loss Account and the Economic Neutrality Surcharge Account for energy supplied through Direct Lines, provided that this energy is generated by production units connected to the Direct Line. The timing of settlement for these quantities is also established.

8. [Decision E-96/2023](#): "Approval of the Network Development Plan (NDP) for the period 2022-2026"

The Five-Year Network Development Plan (NDP) is prepared by the Hellenic Electricity Distribution Network Operator (HEDNO) in accordance with Article 128 of Law 4001/2011, the Distribution Network Operation Code, and relevant Decisions by RAAEY, which provide guidelines for the Plan's preparation.

The NDP includes all necessary projects for the development of the Hellenic Electricity Distribution Network, improvement of services for network users, operation of the electricity markets for Non-Interconnected Islands (NIIs), and support for the electricity market. For each project, the plan provides essential information regarding its purpose, implementation schedule, and financial details, including investment costs and cash flows for 2022 to 2026.

Specifically, the NDP includes:

- Projects for the development and expansion of the network.
- Projects for network strengthening, replacement and renovation.
- Projects to modernize the infrastructure and systems of the DSO.
- Projects to manage the electrical systems of the NIIs.
- Projects for user connection and servicing.

In November 2022, HEDNO submitted the 2022-2026 NDP for approval, as outlined in Article 109 of the HEDNO Operation Code. The submitted NDP updates projects from the approved 2021-2025 NDP and proposes 29 new projects with a total estimated budget of €265.5 million.

RAAEY conducted a public consultation on HEDNO's proposal and, after evaluating the purpose of the included projects, approved the 2022-2026 NDP with this specific Decision, excluding 5 projects concerning specialized IT systems and applications with a total budgeted cost of €143.9 million, which were deemed unsuitable for inclusion in the NDP.

Furthermore, with this Decision, RAAEY requested the DSO to include in a future revision of the NDP the necessary projects for the interconnection of the Southern and Western Cyclades Islands with the Transmission System, as well as the islands of the Northeast Aegean and the Dodecanese, which must be completed no later than 2029.

3.2 Competition and market functioning

3.2.1 Wholesale markets

3.2.1.1 *Description of the wholesale market*

Another historic reform took place in the Greek wholesale electricity markets in 2022, two years after the implementation of the three new short-term electricity markets, namely the Day-Ahead Market, the Intraday Market and the Balancing Market, according to the European Target Model. In the framework of its regulatory powers, RAAEY, following relevant proposals of the Hellenic Energy Exchange Group and IPTO S.A., decided that on the 30th of November 2022 the coupled operation of the Intraday Market through Continuous Intraday Trading (XBID) will commence (RAAEY Decision 862/2022).

By joining the Continuous Intraday Trading platform (XBID), orders entered by Participants for continuous matching in Greece through the XBID platform can be matched with orders submitted by Participants in any other of the twenty-five countries (25) within the Single Intraday Coupling (SIDC) in Europe, if transmission capacity is available. The Greek Intraday Market through the Continuous Intraday Trading is also expected to gain further liquidity, as it will allow, in particular, RES Producers to correct their Market Schedule as close as possible to real time, in order to avoid deviations in the Balancing Market, which will lead to the optimal use of their production with consequent benefits for society.

The Regulatory Authority for Energy issued six decisions to complete the regulatory framework governing the operation of the Continuous Intraday Trading in accordance with Law 4425/2016, after relevant proposals by the market operators (RAAEY Decisions 693/2022, 694/2022, 859/2022, 860/2022, 861/2022 and 862/2022).

A very important milestone was also reached in 2022 in line with the country's commitments as included in the National Recovery and Resilience Plan Greece 2.0, which was approved on July 13 2021 by the Economic and Financial Affairs Council of the European Union (Ecofin) as well as the Reform Plan of electricity markets (under finalization by the Ministry of Energy), in accordance with article 20 of Regulation (EU) 2019/943, following an Opinion by the European Commission dated 29.11.2021.⁵ RAAEY issued eight decisions for the approval of the regulatory framework for the participation of demand (i.e., distributed load) either individually or through Aggregators as well as the participation of Distributed RES in the Balancing Market (RAAEY Decisions 185/2022, 481/2022, 482/2022, 585/2022, 212/2022, 480/2022, 476/2022 and 477/2022). Competition between Balancing Service Providers in this market is therefore strengthened, since both demand and RES will be able to provide balancing services, apart from distributed thermal power generation units.

It is also noted that due to the extraordinary geopolitical conditions and the energy crisis, the Greek State established a Temporary Mechanism, which was applied as of July 8, 2022, first in the Day-Ahead market and then in the Intraday Market. According to the mechanism part of the revenue to which the Participants/Electricity Producers in the Day-Ahead and Intraday Markets were entitled from their participation in those markets, was not cashed out to the Participants but only a "regulated revenue" was cashed out. The amount kept (not cashed out) constituted the Excess Revenue which was credited to the national Energy Transition Fund to be returned eventually to the consumers.

Figure 1 provides the evolution of the weighted average selling price in the Day Ahead and Intraday Markets, over the period of the implementation of the Temporary Mechanism (08.07.2022-31.12.2023), while Figure 2 provides the evolution of the sales income and amount returned from the Day Ahead and Intraday Markets, over the period of the implementation of the Temporary Mechanism.

⁵ https://energy.ec.europa.eu/system/files/2021-12/adopted_opinion_plan_greece_c_2021_8532_en.pdf

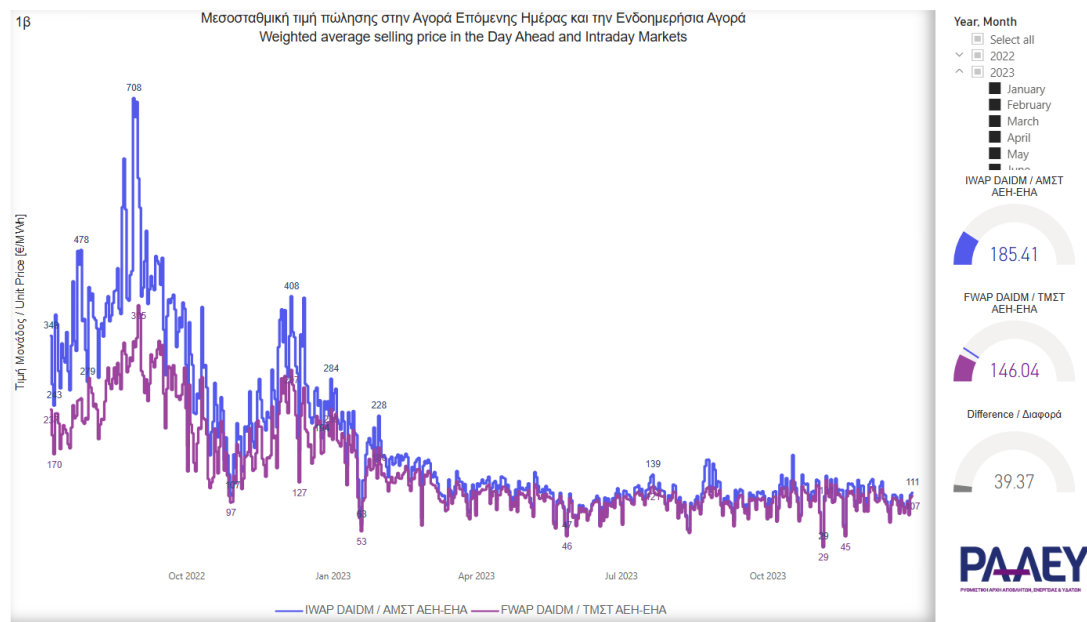


Figure 1: Evolution of the weighted average selling price in the Day Ahead and Intraday Markets, over the period of the implementation of the Temporary Mechanism (08.07.2022-31.12.2023).

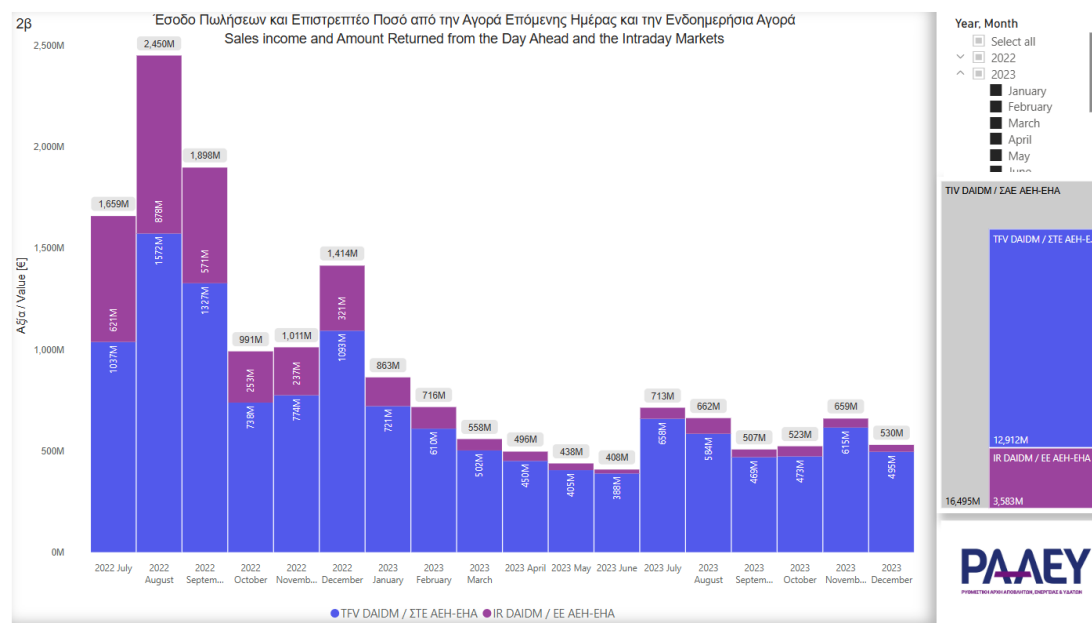


Figure 2: Evolution of the sales income and amount returned from the Day Ahead and Intraday Markets, over the period of the implementation of the Temporary Mechanism (08.07.2022-31.12.2023).

RAAEY by Decision 604/2022, following a relevant proposal by the Energy Exchange Clearing House and a public consultation, amended the Day-Ahead and Intraday Market Clearing rulebooks in order to incorporate the provisions required for the implementation of the Temporary Mechanism.

With regards to the fees and charges paid by participants in the Day-Ahead, Intraday and Balancing markets as well as by RES and HECHP producers to DAPEEP S.A. (to cover its operational and investment costs), RAAEY, following relevant recommendations of the competent Operators took the following actions:

a) maintained the fees for the Day-Ahead and Intraday Markets in 2023 at the levels of 2022 (RAAEY Decision 909/2022).

b) approved an increase in the fees of the Balancing Market, starting from 1.2.2023, taking into account the forecasts of IPTO S.A. for 2023, the under-recovery of relevant required revenue for the year 2022, but also the intention to establish a corrective clearing mechanism so that relevant over-recoveries of revenue are returned to the participants, if there is a deviation compared to the forecasts (Decision 945/2022).

c) amended the fees received by the Energy Exchange Clearing House for the clearing of the Balancing Market to introduce specific provisions for Participants who wish to exit the market (RAAEY Decisions 98/2022 and 99/2022).

d) determined the Unit Charge collected by DAPEEP S.A. from RES and HECHP Producers at €0.44/MWh for the year 2023 (RAAEY Decision 899/2022).

In 2022 RAAEY also issued a series of Decisions according to the provisions of Regulation (EU) 2015/1222 on the establishment of guidelines on capacity allocation and congestion management (hereafter "CACM"), of Regulation 2016/1719 on the establishment of a guideline on future capacity allocation (hereinafter "FCA") and Regulation (EU) 2017/2195 on the establishment of a guideline on electricity balancing (hereinafter "EBGL"). The Decisions mentioned below are the result of close cooperation with the Regulatory Authority of Italy (Greece Italy Capacity Calculation Region GRIT CCR) and the Regulatory Authorities of Bulgaria and Romania (Southeast Europe Capacity Calculation Region - SEE CCR):

a) CACM: Decisions 329/2022 and 330/2022 on the modification of the fallback procedures within the GRIT CCR and within the SEE CCR, respectively.

b) EBGL: Decision 363/2022 which approved the request of IPTO S.A. to join the MARI and PICASSO European platforms, concerning the exchange of balancing energy products with other European EU member countries in July 2024.

Taking into account the three Decisions mentioned above, RAAEY has now issued during the period 2016-2022 one hundred and nine (109) Decisions concerning terms and conditions or methodologies that specify the coupled operation of the Electricity Markets (59 CACM Decisions, 29 FCA decisions and 21 EBGL Decisions), either in cooperation with all the EU Regulatory Authorities, or the Regulatory Authorities of each CCR.

Additionally, in 2022, RAAEY approved the request for a derogation of IPTO S.A. from the application of the minimum margin of 70% that is required to be available for cross-zonal energy trading for the border of Greece-Bulgaria bidding zones, in accordance with the provisions of the European Regulation 943/2019, incorporating milestones to achieve this target, according to the Agency for the Cooperation of Energy Regulators' (ACER's) recommendations (RAAEY Decision 929/2022).

After relevant proposals from IPTO S.A., HENEX S.A., Energy Exchange Clearing House S.A., HEDNO S.A. and the Operator of RES and Guarantees of Origin DAPEEP S.A., RAAEY proceeded in 2022 with the issuance of a series of Decisions, concerning other key market issues, such as the following: a) the definition of the numerical values of the parameters for the charges imposed on those who participate in the Energy Exchange Markets and the Balancing Market in case of non-compliance, b) the formation of the Pre-Funded Resources which are used for the delinquency of the Clearing Members, c) the modification of the methodology applied by IPTO S.A. for the calculation of infeasible market schedules, d) balancing market rules for units undergoing a test/trial operation period and/or commissioning, e) the unit cost of losses for 2023 in the context of the implementation of the compensation mechanism between the Electricity Transmission System Operators, f) the guarantees of HEDNO S.A. for its coverage in case of non-payment by electricity suppliers and self-consumers of Public Services Obligation (PSO) charges, g) the guarantees of DAPEEP S.A. in order to be secured from the financial risk of non-payment of the revenues of the RES and HECHP Special Account referred to in paragraph 5 of article 4 of Law 4585/2018, and h) the approval of the Capacity Allocation Rules at the Bidding Zone Borders between Greece and countries outside the EU (Albania, North Macedonia and Turkey) for 2023.

The forward market, operating in parallel with the Day-Ahead Market, allows Participants, through the conclusion of future contracts, to hedge against short-term price volatility, while offering an incentive to Producers to make their production available at competitive prices, ensuring in the long term a part of the necessary for their sustainability cash flows. During 2022, RAAEY, with its Decision 928/2022, following a relevant recommendation of the Energy Exchange, decided to increase the forward hedging ratio (A), i.e., the percentage (%) of energy quantities that are included in the validated Physical Offtake Nominations and correspond to energy quantities of trades on Energy Financial Instruments (either through organized markets such as the Energy Financial Market of HENEX S.A., or through bilateral contracts), from 30% to 40%, so as to give the Supplier with a retail supply share of more than 40% a greater possibility of mitigating the effects of a sharp short-term price volatility. It should be noted that for the rest of the Suppliers (e.g. suppliers with a retail market share of less than forty percent), with the relevant 1014/2021 Decision of RAAEY, there is no relevant upper limit, and they can enter into forward contracts for their entire portfolio.

In 2022, the TSO (IPTO S.A.) continued the testing application of the basic principles of the methodology for distinguishing the energy for non-balancing purposes, including redispatching, from the energy for balancing purposes in order to draw information from the test results and make the necessary adjustments to the methodology in order to submit it, along with the necessary modifications to the balancing market rulebook, to RAAEY for approval.

Finally, taking into account the relevant update of the Operator of the Special RES and HECHP account, DAPEEP S.A., as well as the corresponding information on the inflows and outflows (actual and projections) for the years 2022-2023 the Authority with its Decision 931/2022 decided to maintain the RES levy for the year 2023 equal to 17 €/MWh, that is equal to the Unit Charges determined in Decision ΥΠΕΝ/ΓΔΕ/76979/4917 (Gazette B' 3373/31.08.2019) for the years 2019 and 2020 and Decisions 1654/2020 and 1063/2021 for the years 2021 and 2022.

Wholesale Market Monitoring

RAAEY, within the framework of its responsibilities regarding the monitoring and supervision of the wholesale electricity market and seeking its efficient operation, while ensuring the protection and comprehensive information of consumers, as well as of market Participants, developed and published on its website⁶ a series of tools including data concerning the operation of the wholesale market according to the European Target Model.

Electricity Wholesale Market Reports

RAAEY has implemented a Market Monitoring Mechanism which automatically collects a large amount of data sent by the Market Operators (HENEX S.A. and IPTO S.A.) and produces monthly reports regarding the operation of the Wholesale Electricity Market, which are posted on the website of the Authority⁷. More specifically, graphs and statistics are presented, which relate to the operation of each individual electricity wholesale spot market:

1. Day-Ahead Market
2. Intraday Market
3. Balancing Market
 - a. Integrated Scheduling Process
 - b. Imbalance Settlement Procedure

European Electricity Wholesale Market Maps

In collaboration with the “Smart RUE” research group of the Electrical Energy Systems Laboratory of the School of Electrical and Computer Engineering of the National Technical University of Athens,

⁶ <https://www.rae.gr/en/market-monitoring/>

⁷ <https://www.rae.gr/en/market-monitoring/greek-wholesale-electricity-markets/>

RAAEY developed and put into operation on its website, six information fields ("European Maps") with the following information:

1. European Electricity Day-Ahead Market Price Map⁸
2. European Map of Electricity Production from RES⁹
 - a. Percentage of total RES production penetration in relation to the domestic load demand (RES penetration)
 - b. Amount of electricity produced by all installed RES (RES generation)
 - c. Amount of electricity produced by Photovoltaic systems (PV generation)
 - d. Amount of electricity produced by wind systems (WIND generation)
3. European Cross-Border Electricity Trade Balance Map¹⁰

Graphs of the Greek Electricity Market

In addition, and in collaboration with the Smart RUE research group, two sections were added to RAAEY's website with detailed statistics regarding the operation of the domestic electricity market in terms of:

1. The Availability of Resources¹¹, where the following information is depicted:
 - a. the availability of distributed generation units
 - b. the availability of imports and exports per border and
 - c. the hourly forecast of resource availability in comparison with the load forecast and the RES production forecast according to the ISP settlement
2. The Energy Mix of the domestic Day-Ahead Market¹², where there are reflected in more detail the following:
 - a. the volumes of transactions per participating category, distinct from the supply side (sell) and the demand side (buy), in comparison with the average Market Clearing Price (MCP), in a weekly and daily observation window
 - b. the total imports and exports of electricity per market time unit, considering the quantities of energy between the coupled borders, based on the solution of the EUPHEMIA single price coupling algorithm (implicit/explicit trades)
 - c. the net volumes from the sale and purchase of energy per participating category, as calculated during the settlement of intraday electricity market auctions.

Moreover, RAAEY developed dynamic graphs showing the Energy Balance¹³ from:

- Day Ahead Market (DAM Schedule)
- Day Ahead Market and Intraday Market (Market Schedule)

⁸ <https://www.rae.gr/en/market-monitoring/european-wholesale-markets/>

⁹ <https://www.rae.gr/en/market-monitoring/european-wholesale-markets/european-map-of-electricity-production-from-res/>

¹⁰ <https://www.rae.gr/en/market-monitoring/european-wholesale-markets/electricity-cross-border-trading-map/>

¹¹ <https://www.rae.gr/en/market-monitoring/greek-wholesale-electricity-markets/electricity-prices-statistics/resources/>

¹² <https://www.rae.gr/en/market-monitoring/greek-wholesale-electricity-markets/electricity-prices-statistics/energy-mix/>

¹³ <https://www.raae.gr/energeia/en/market-monitoring/greek-wholesale-electricity-markets/electricity-prices-statistics/energy-mix/>

- Integrated Scheduling Process (ISP Schedule)

For each schedule (DAM Schedule, Market Schedule, ISP schedule), three graphs are shown:

- Daily Energy Balance for each hour of any selected date, since the implementation of the Target Model in Greece
- Average Energy Balance for each hour of any selected time-period, since the implementation of the Target Model in Greece
- Cumulative (Total) Energy Balance for each hour of any selected time-period, since the implementation of the Target Model in Greece

Figures 3 - 5 provide the average hourly energy mix for the DAM Schedule, Market Schedule and ISP Schedule respectively for 2023.

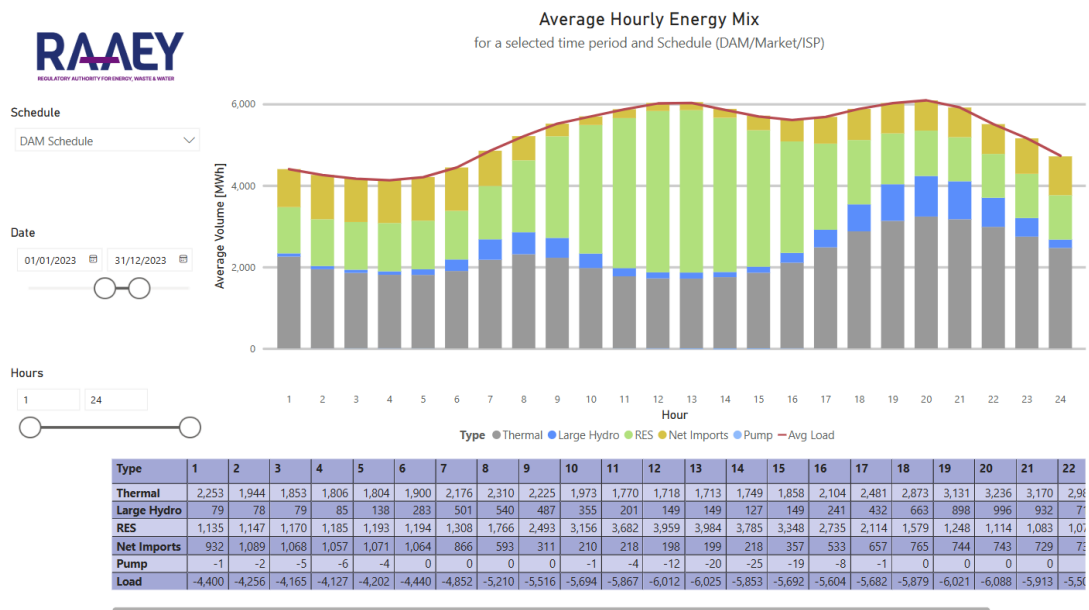


Figure 3: Evolution of the average hourly Energy Mix over 2023 for the DAM Schedule.

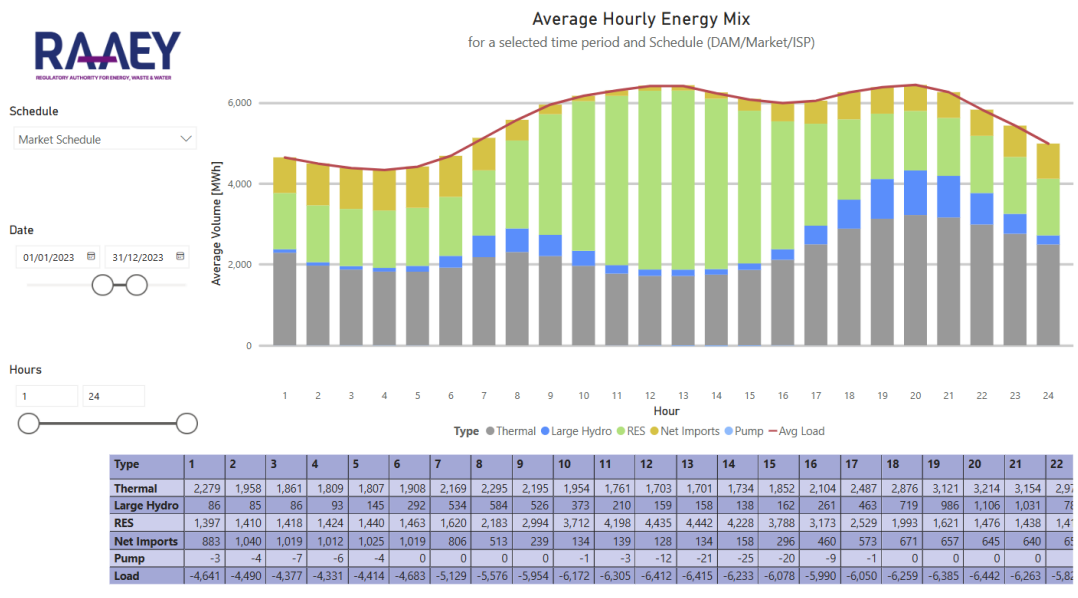


Figure 4: Evolution of the average hourly Energy Mix over 2023 for the Market Schedule.

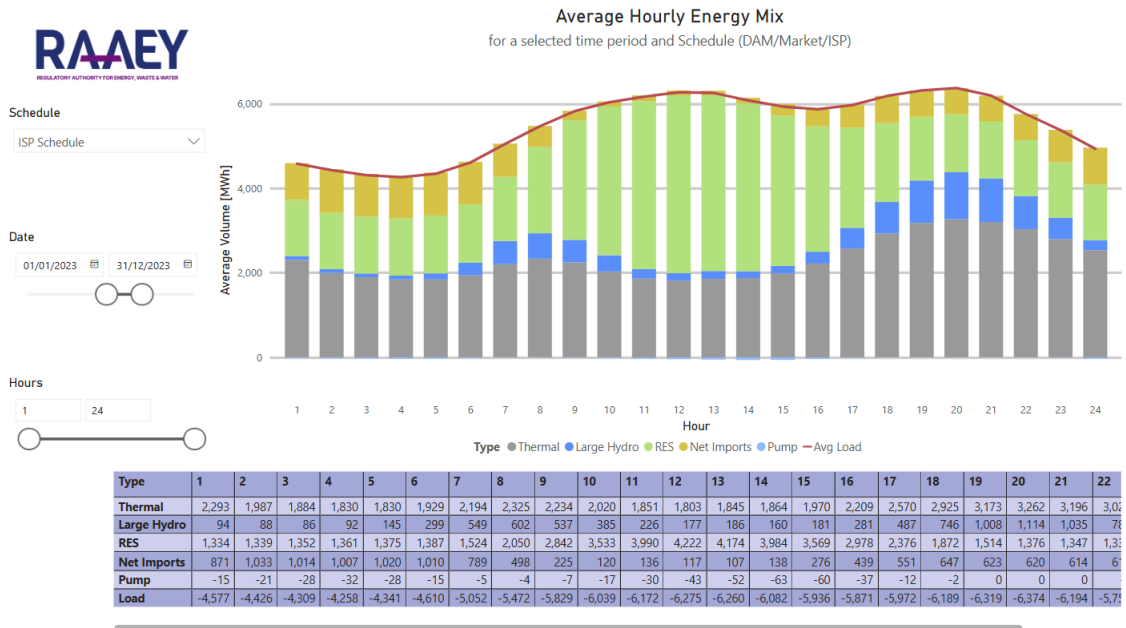


Figure 5: Evolution of the average hourly Energy Mix over 2023 for the ISP Schedule.

Statistics on the Implementation of the Temporary Mechanism

Finally, RAAEY has added to its website a dynamic graph with the complete history of the financial statistics of the Temporary Mechanism for windfall profits in the electricity sector, since the day of its implementation (initially in the Day-Ahead and then in the Intraday Market). The dynamic field above gathers four graphs with the following information:

1. Weighted average selling price before and after the application of the temporary mechanism, considering:
 - a. the total supply mix in the Day-Ahead Market and
 - b. the total supply mix in the Day-Ahead Market and the Intraday Market
2. Total value of sales before and after the implementation of the Temporary Mechanism, as well as the total amount flowing to the Energy Transition Fund, considering:
 - a. the total supply mix in the Day-Ahead Market and
 - b. the total supply mix in the Day-Ahead Market and the Intraday Market

3.2.1.2 Installed Capacity and Generation

In 2023, the installed capacity in the interconnected system of Greece was increased (24,471 MW) compared to 2022 (22,234 MW), due to the increase of RES units' installed capacity from 10,173 MW in 2022 to 12,385 MW in 2023 and the increase of natural gas units' installed capacity from 6,019 MW in 2022 to 6,043 MW in 2023. The installed capacity of lignite units amounted to 2,872 MW while the Large Hydro capacity remained at 3,171 MW in 2023. In terms of installed capacity (excluding RES), PPC S.A. held a market share of 71.74% compared to 71.92% in 2022, whereas the market share of PPC's conventional units including RES amounted to 35.43% compared to 39.02% in 2022.¹⁴

¹⁴ Please note that in February 2022, Melitis Lignite and Megalopolis Lignite were merged by absorption by PPC S.A..

Installed capacity and production by fuel, in 2023	Installed capacity (MW)	Total annual production (TWh)	Share in produced volume, including RES (%)
Lignite	2,872	4.51	10.28%
Large Hydro (P > 15 MW)	3,171	4.05	9.22%
Natural gas	6,043	14.63	33.34%
Total Thermal + Large Hydro (1)	12,086	23.19	52.84%
Total RES (Grid + Network) (2)	12,385	20.68	47.12%
Total (1+2)	24,471	43.88	100%

Table 9: Installed Capacity and Production by fuel, including RES, in the Interconnected System in 2023

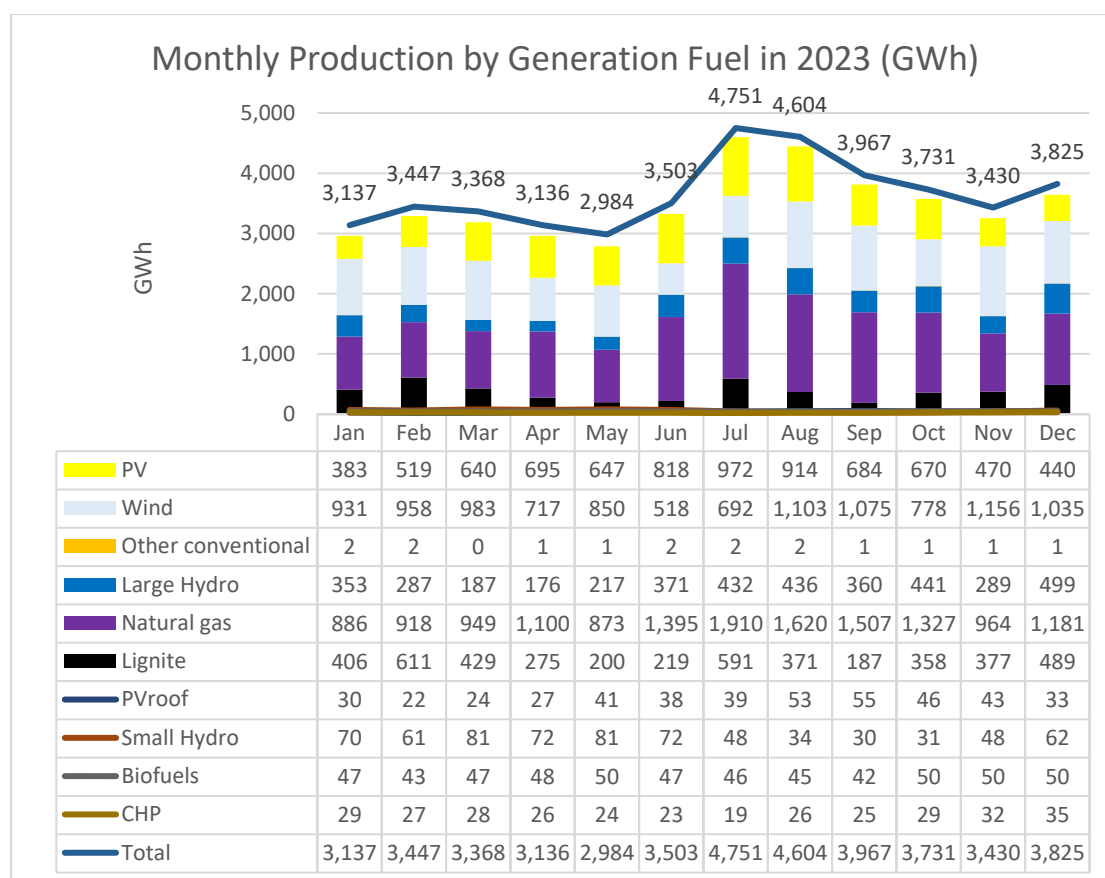


Figure 6: Monthly Production by Generation Fuel in 2023 (Interconnected System)

In terms of the generation mix, in 2023 the lignite production showed a decrease of 19.21% compared to 2022. More specifically, in 2023 lignite production amounted to a total of 4.51 TWh (5.59 TWh in

2022). Regarding other technologies, the electricity generation from natural gas decreased to 14.63 TWh (a decrease of 18.49% compared to 2022, 17.95 TWh), while hydroelectric production slightly increased by 1.05%, amounting to 4.05 TWh in 2023 (from 4 TWh in 2022). Finally, RES and HECHP generation continued the upward course of the previous year and reached 20.68 TWh, recording an increase of 9.63% compared to 2022 (18.86 TWh). Overall, domestic production showed a decrease of 5.49 % reaching 43.88 TWh compared to 46.43 TWh in 2022.

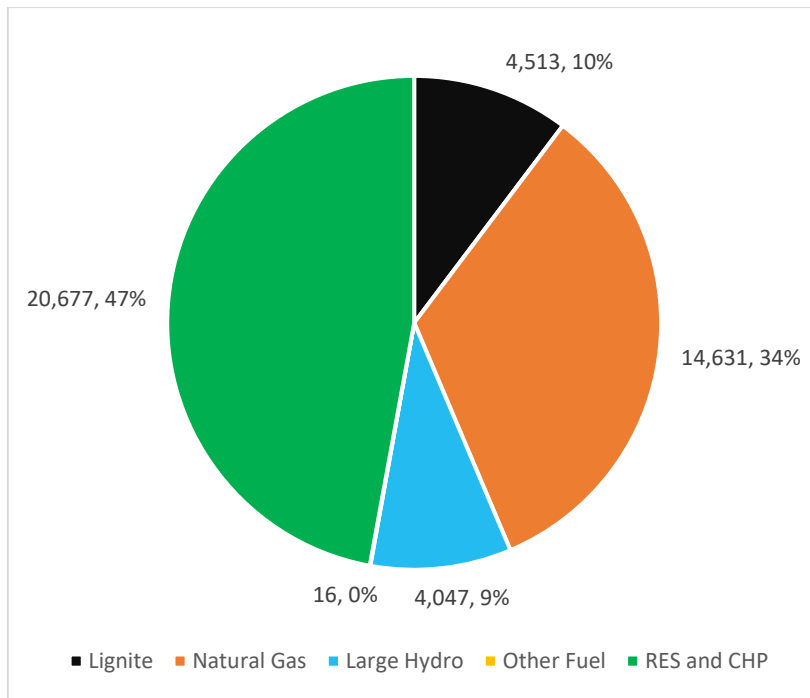


Figure 7: Electricity generation in GWh by energy source in 2023 (Interconnected System)

On a monthly basis, generation from lignite showed a sharp fluctuation between 187 GWh and 611 GWh. September was the month with the lowest demand for lignite-based power while February was the month with the highest demand in 2023. Electricity generation from natural gas showed a sharp fluctuation as well between 873 GWh (May) and 1,910 (July) GWh. RES generation also showed great fluctuations (between 1,461 GWh in January and 2,149 GWh in August 2023). The balance of interconnections in 2023 sharply increased by 42.32% compared to 2022 and amounted to 4.91 TWh (3.45 TWh in 2022). The fluctuations of electricity imports and exports through interconnections (Figures 8 & 9) were significant over 2023, with the lowest value being recorded in September (-133 GWh) and the highest value in January (1,046 GWh).

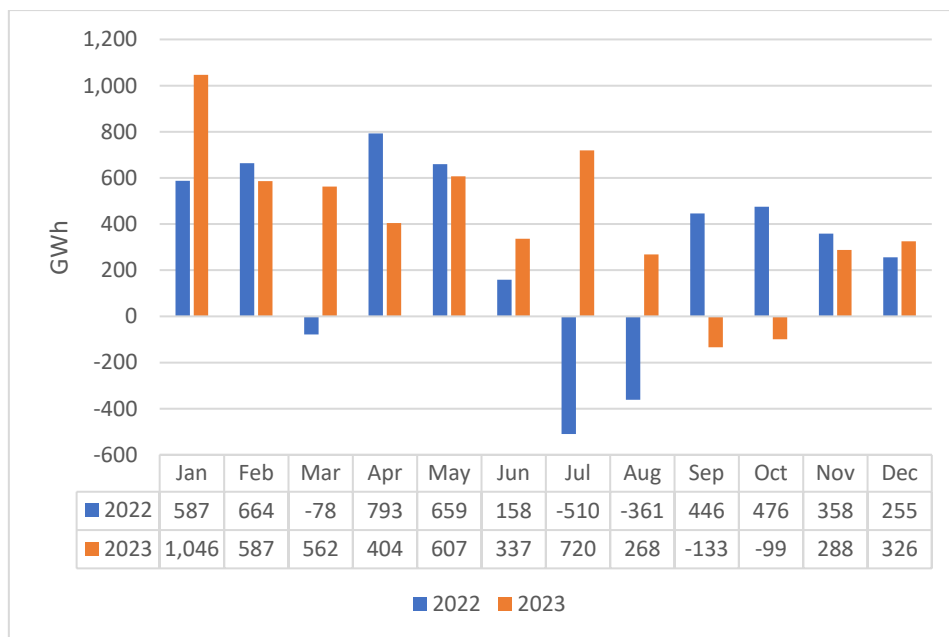


Figure 8: Evolution of Electricity Trading Balance of physical flows at interconnection points during 2022 and 2023 (GWh)

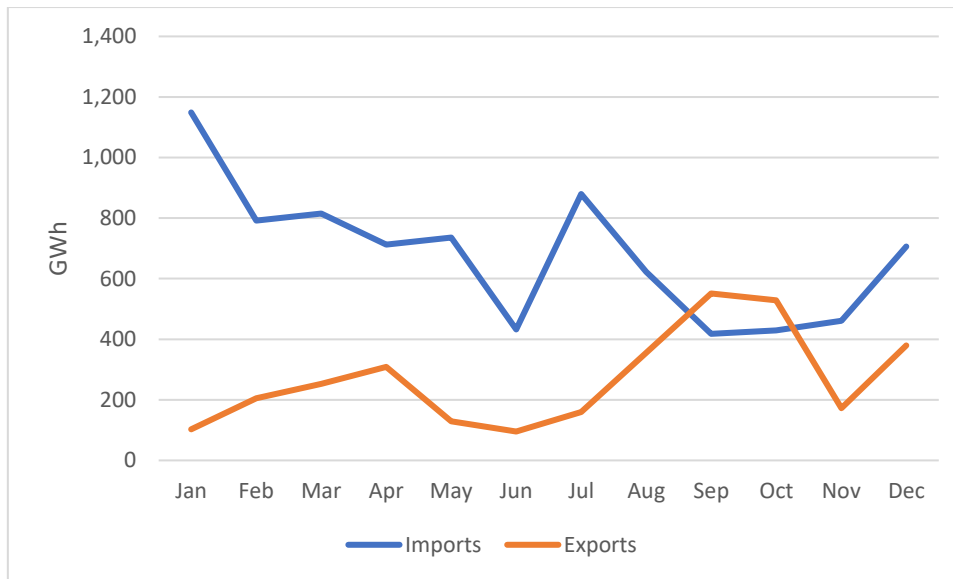


Figure 9: Physical Electricity Flow Imports and Exports (GWh) 2023

3.2.2 Retail market

3.2.2.1 Market opening and competition

The electricity retail market has been fully liberalised since July 2013. Public Service Obligations' (Supplier of Last Resort, Universal Service Supplier) Tariffs continue being regulated.

With Decision 692/2011 (and, subsequently, in the new Electricity Supply Code), RAAEY 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.

All suppliers publish their prices on their websites. RAAEY 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.

The retail electricity market description is divided into two categories: the Interconnected and Non-Interconnected Systems. This differentiation is a direct result of the liberalisation of electricity supply in the Non-Interconnected Islands (NII) being implemented on January 1, 2018, as specified in Decision 908/2017, published in Gazette B' 4461. Consequently, there is an uneven level of development in these two segments. For, information regarding the retail electricity markets in the non-interconnected islands refer to page 94.

With respect to the electricity supply activity within the Interconnected System, in 2023, competition remained at similar levels to those observed in 2022, with no significant issues impacting the accurate representation of electricity consumers. Throughout 2023, no new entrants emerged in the supply sector, while two companies, KEN and Watt & Wolt, were absorbed by other electricity supply companies, VOLTON and Protergia.

In 2023, a total of 19 suppliers operated within the retail electricity market of the Interconnected System. Among them, the five companies with the most significant market share, namely Public Power

Corporation S.A., Mytilineos S.A., Heron Thermoelectric S.A., Elpedison Electricity Production Unipersonal S.A., and NRG Supply and Trading Energy S.A., continued to act as Universal Service Suppliers starting from June 23, 2022 for a period of two years. Furthermore, Public Power Corporation S.A. continued to be sole Last Resort Electricity Supplier from 29 September 2022 to 28 September 2024, according to Decision 712/2022 published in the Gazette B' 5084/28.09.2022. Universal Service Suppliers and the Supplier of Last Resort are not included in Table 10.

	Supplier Name:
1.	PPC
2.	ELINOIL
3.	ELTA
4.	ELPEDISON
5.	ZENITH
6.	HERON
7.	SOLAR ENERGY SOUMPASIS
8.	PROTERGIA
9.	NRG
10.	OTE ESTATE
11.	FYSIKO AERIO ELLADOS
12.	VOLTERRA
13.	VOLTON
14.	WE ENERGY
15.	VIENER
16.	VIOLAR
17.	K.V. MARKOU
18.	KEN (Merged with VOLTON in August 2023)
19.	WATT & VOLT (Merged with PROTERGIA in December 2023)

Table 10: Active electricity suppliers in 2023

Tables 11, 12 and 13 below provide a detailed overview of supplies and consumption figures across various consumer categories and suppliers within the country's Interconnected System for 2023. These three tables do not include data on the SoLR.

It's important to note that Table 11 specifically reflects the number of meters associated with active Suppliers as of December 31, 2023. This includes data for 26 Suppliers, including two suppliers that ceased their operations due to mergerings during the year, the Last Resort Supplier (SoLR), which did not have consumers at that time as well as the 5 Universal Service Suppliers (USSs).

On the other hand, Tables 12 and 13 comprehensively outlines the total consumption data for all months of the year. It encompasses information from all 27 Suppliers who were active throughout the year.

Supplier	LV				MV		HV	TOTAL
	Households	Social Tariffs Households	Commercial Industrial	Other	Commercial Industrial	Other	Industrial	
PPC	3,461,085	358,652	813,816	295,023	7,281	1,707	222	4,937,786
PROTERGIA	310,861	25,439	93,524	565	2,191	8	36	432,624
ZENITH	238,385	30,011	27,988	732	132	0	0	297,248
ELPEDISON	218,920	18,685	48,520	370	484	4	23	287,006
HERON	194,772	18,294	52,895	508	1,855	14	70	268,408
NRG	132,071	17,027	57,556	330	907	8	13	207,912
FYSIKO AERIO	130,405	9,376	17,452	540	297	9	0	158,079
PPC-USS	104,124	8,129	36,786	6,114	0	0	0	155,153
VOLTON	63,051	6,519	18,159	1,359	117	3	0	89,208
VOLTERRA	13,264	950	6,633	209	409	18	22	21,505
PROTERGIA -USS	6,467	459	1,907	404	0	0	0	9,237
ELPEDISON-USS	6,341	392	1,931	425	0	0	0	9,089
HERON-USS	5,177	315	1,603	309	0	0	0	7,404
NRG-USS	4,065	283	1,147	228	0	0	0	5,723
ELINOIL	2,257	137	1,049	4	30	0	0	3,477
OTE ESTATE	478	6	1,893	7	2	0	0	2,386
WE ENERGY	945	27	831	7	321	1	0	2,132
SOLAR ENERGY	379	32	263	0	158	0	0	832
ELTA	3	0	492	29	11	0	0	535
VIOLAR	19	0	6	0	5	0	0	30
VIENER	0	0	0	0	23	0	0	23
K.V. Markou	0	0	2	2	7	0	1	12
EUNICE TRADING	0	0	0	0	0	0	1	1
HERON II BOETIA	0	0	0	0	0	0	0	0
WATT & VOLT	0	0	0	0	0	0	0	0
KEN	0	0	0	0	0	0	0	0
Total	4,893,072	494,737	1,184,334	307,162	14,146	1,772	388	6,895,611

Table 11: Total number of connections per Supplier and Consumer Category in the interconnected Network (31.12.23, Source: HEDNO S.A. for LV and MV, IPTO S.A. for HV)

MWh	LV				MV		LV & MV
Supplier	Households	Social Tariffs (households)	Commercial Industrial	Other	Commercial Industrial	Others	Total
PPC	7,938,665	1,244,861	4,222,864	2,575,422	2,349,546	1,378,252	19,709,610
PROTERGIA	626,505	52,509	1,019,840	9,085	1,646,967	23,360	3,378,266
HERON	622,699	70,857	985,503	13,402	1,583,599	18,222	3,294,282
NRG	392,118	59,487	851,578	8,478	925,457	13,287	2,250,406
ELPEDISON	669,261	73,496	597,474	6,325	658,113	3,428	2,008,097
FYSIKO AERIO	360,071	31,139	254,465	8,097	676,608	24,836	1,355,215
ZENITH	538,721	87,267	276,204	6,589	46,886	0	955,667
WATT & VOLT	369,356	42,825	423,956	2,832	77,972	39	916,980
VOLTERRA	46,182	3,749	154,815	9,280	601,613	52,967	868,607
VOLTON	167,453	21,991	132,690	8,975	56,828	850	388,787
PPC-USS	161,038	37,044	71,152	8,506	0	0	277,740
KEN	43,487	5,012	94,889	490	18,014	0	161,892
ELINOIL	8,525	605	16,172	57	47,415	0	72,776
WE ENERGY	3,682	91	22,173	267	35,132	3,365	64,709
VIENER	0	0	0	0	43,305	0	43,305
ELTA	7,702	448	13,764	491	14,292	0	36,698
OTE ESTATE	1,867	26	6,337	850	11,942	0	21,021
SOLAR ENERGY	1,040	137	5,179	0	8,805	0	15,161
PROTERGIA-USS	8,577	2,049	3,449	446	0	0	14,521
ELPEDISON-USS	7,653	1,648	3,999	407	0	0	13,708
HERON-USS	6,882	1,289	3,014	395	0	0	11,580
NRG-USS	5,025	1,192	2,357	198	0	0	8,771
K.V. Markou	0	0	5	9	7,551	0	7,565
VIOLAR	90	0	12	0	3,200	0	3,302
HERON II BOETIA	0	0	0	0	0	0	0
Total	11,986,600	1,737,724	9,161,892	2,660,600	8,813,245	1,518,606	35,878,666

Table 12: Electricity Consumption per Supplier and Consumer Category (LV & MV) in the interconnected Network (2023, MWh, Source: HEDNO S.A.)

Supplier	Consumption (GWh)
PPC	4,373.1
HERON	949.3
WATT & VOLT	833.6

ELPEDISON	798.0
PROTERGIA	234.7
NRG	76.6
VOLTERRA	39.9
CORINTHOS POWER	5.0
HERON II BOETIA	4.3
Total	7,314.5

Table 13: Electricity Consumption per Supplier of HV transmission consumers in the interconnected Network (2023, GWh, Source: IPTO S.A.)

In 2023, PPC retained its position as the dominant supplier in the retail electricity market. However, its market share showed a slight decline compared to the previous year, accounting for 71.61% of the total number of supplies in the interconnected system's LV and MV, down from 72.55% in 2022. Similarly, PPC represented 54.93% of the total MV & LV consumption, a decrease from 56.57% in 2022.

For a comprehensive view of the market landscape, Figures 10 and 11 display the market shares of Electricity Suppliers within the Interconnected System. These figures provide insights into both the number of supplies and consumption volume, drawing from data sourced from the DSO for the year 2023.

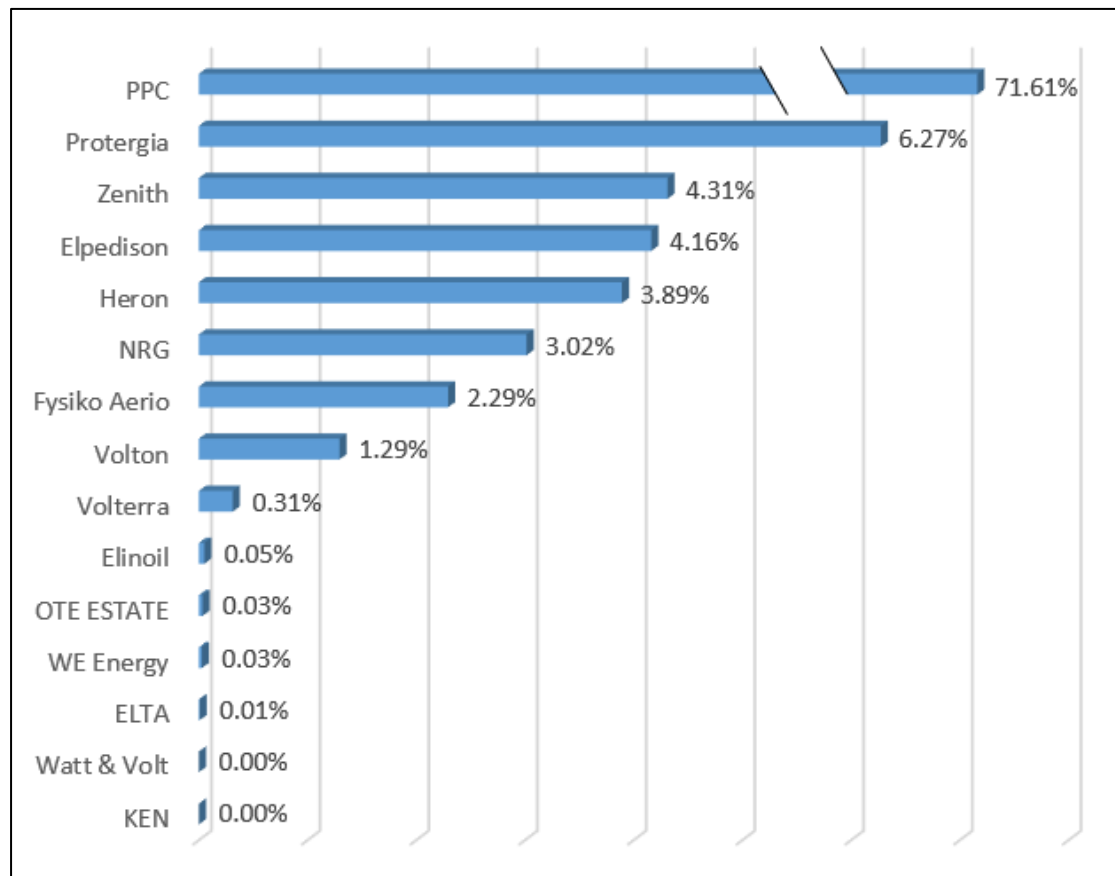


Figure 10: Market shares of suppliers based on number of meters in the retail electricity market, Interconnected System (LV & MV, 2023, Source: HEDNO S.A.)

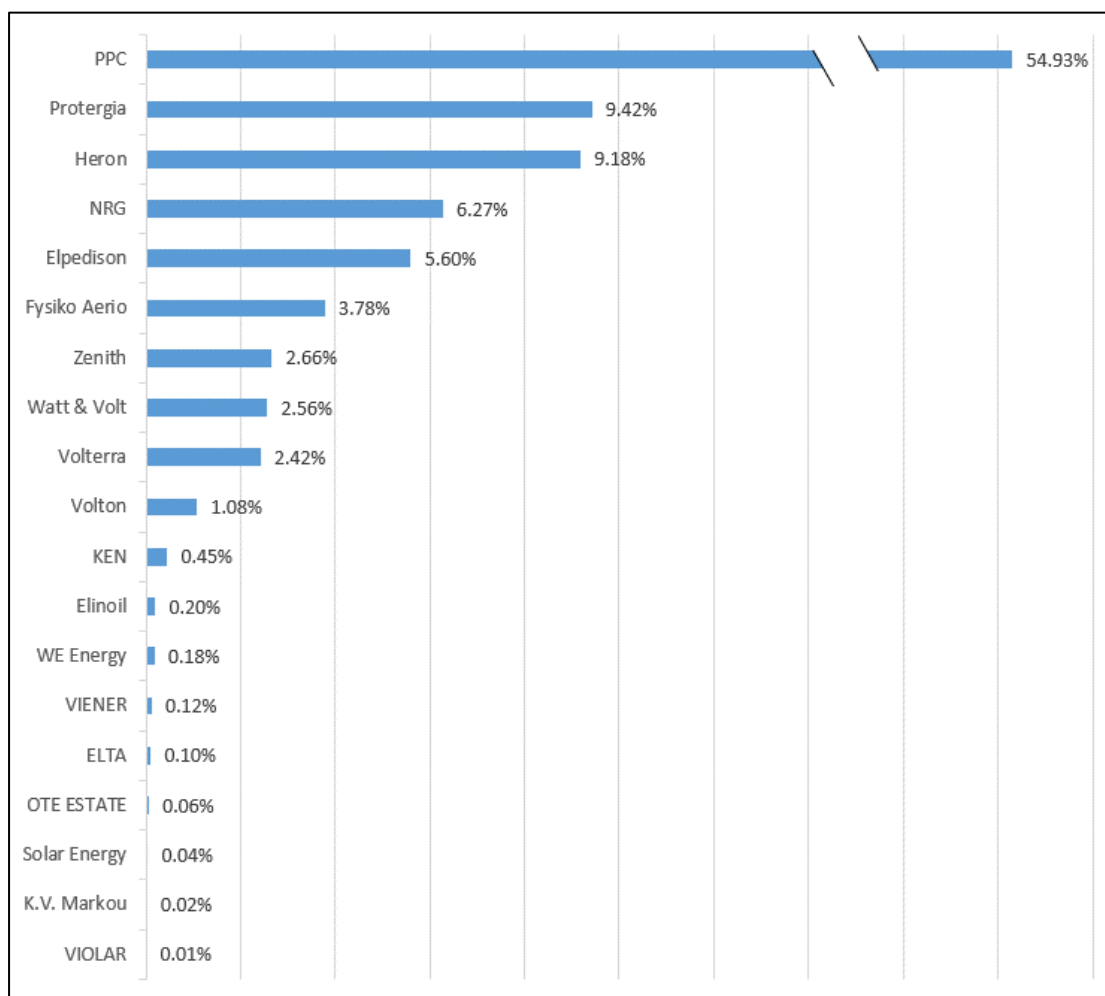


Figure 11: Market shares of suppliers based on consumption in the retail electricity market, Interconnected System (LV & MV, 2023, Source: HEDNO S.A.)

The Herfindahl-Hirschman Index (HHI) for 2023, calculated based on consumption volume within the Interconnected System, stands at 3,298. While this index notably surpasses the high market concentration threshold of 2,000, it does so to a lesser extent than in 2022 (3,502).

The subsequent table provides an overview of the orders to the DSO pertaining to supplier switching, disconnections, reconnections, and new supply connections that occurred within the Interconnected System during 2022. The encompasses both the number of orders issued and the corresponding orders that were effectively carried out by HEDNO.

Consumers' Categories	Number of switching orders issued	Number of switching orders executed	Number of disconnection orders issued	Number of disconnection orders executed	Number of reconnection orders issued	Number of reconnection orders executed	Number of new connection orders issued	Number of new connection orders executed
LV Consumers	679,987	669,263	626,784	327,064	125,733	125,569	51,705	49,967
MV Consumers	2,310	2,237	364	97	278,907	278,522	1,348	1,480
Total LV & MV Consumers (Interconnected System)	682,297	671,500	627,148	327,161	404,640	404,091	53,053	51,447

Table 14: Switching, disconnection, reconnection and new connection orders issued to and executed by HEDNO per consumer category (LV & MV) in the interconnected System (2023, Source: HEDNO S.A.)

Lastly, as illustrated in the following figures, there continues to be a visible upward trajectory in the number of consumers being supplied electricity by the Universal Service Suppliers (USSs), starting in 2016. Household consumers remain the prevailing category within this trend. In 2023, the number of consumers supplied by the USSs slightly increased compared to 2022, with 135,752 households and 50,854 non-households being supplied. In addition, electricity consumption saw a notable increase, reaching 258,634 MWh for households and 115,740 MWh for non-households in 2023. This rise contrasts with the previous year's decrease in consumption. It is notable that there were no MV consumers supplied by the USSs within 2023.

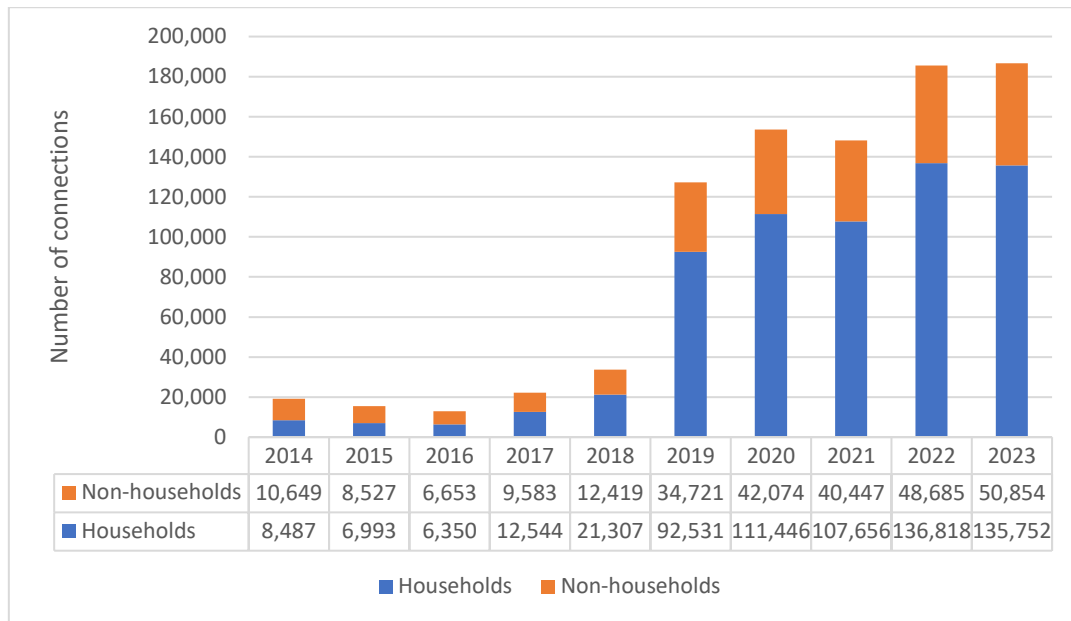


Figure 12: Electricity connections supplied under the Universal Service Suppliers, Interconnected System (LV & MV, 2023, Source: HEDNO S.A.)

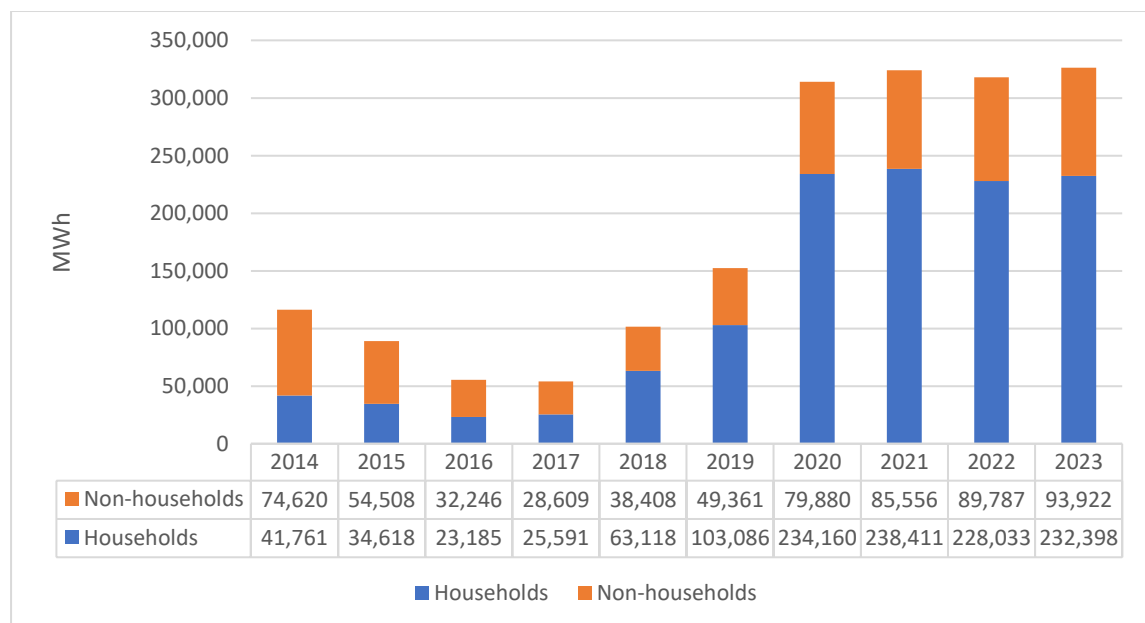


Figure 13: Electricity consumed under the Universal Service Suppliers, Interconnected System (MWh, LV & MV, 2023, Source: HEDNO S.A.)

3.2.2.2 *Prices for household consumers*

Prices for all electricity consumers have been fully liberalized since 01.07.2013. The only regulated tariffs are those under Public Service Obligations, i.e. the Social Tariffs and the prices offered under the Supplier of Last Resort and by the Universal Service Suppliers.

In accordance with Article 140, paragraph 6 of Law 4001/2011, RAAEY monitors deregulated retail prices. If it identifies abusive behavior, such as excessively high prices, the regulator may intervene after the fact (ex-post), provided the intervention adheres to the principle of proportionality.

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 RAAEY regularly publishes comparative estimates for household and small commercial consumers under the various prices on its website (both by PPC and by the alternative suppliers). RAAEY 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.

RAAEY, in the context of its responsibilities for monitoring 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 liberalised, 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. RAAEY 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 by themselves 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 household tariffs that are offered to vulnerable consumers as well as the tariffs of the USSs and SoLR that are approved by RAAEY.

A significant update to Greece's energy support framework occurred with the introduction of a new category to the Social Household Tariff (KOT) scheme, specifically targeting large-family households. This new category, designated KOT C, was established by Ministerial Decision ΥΠΕΝ/ΔΗΕ/136162/2333¹⁵ and became effective on February 1, 2024. It joins the two pre-existing categories: KOT A, which serves consumers in severe need, and KOT B, for households with low incomes. The reform aims to provide more tailored support to vulnerable groups by differentiating the aid they receive.

Each category is entitled to a specific discount on the competitive portion of their electricity bill. KOT A beneficiaries receive a reduction of €0.075 per kilowatt-hour, while the discount for KOT B beneficiaries is set at €0.045 per kilowatt-hour. The newly established KOT C provides the most substantial unit

¹⁵ The Ministerial Decision is available online at: <https://search.et.gr/el/fek/?fekId=602219>

discount at €0.100 per kilowatt-hour. For instance, assuming a supplier's base rate is €0.15/kWh, the final price for a KOT A consumer would be €0.075/kWh, for KOT B it would be €0.105/kWh, and for a KOT C household, it would be just €0.05/kWh.

A crucial aspect of this support mechanism involves exemptions from network fees. Consumers in both the KOT A and the new KOT C categories are fully exempt from all transmission and distribution system usage charges. The benefits for KOT B consumers are more limited, as they are exempt only from the fixed component of the distribution network charge. Eligibility for all KOT categories is tied to specific income criteria and four-month electricity consumption thresholds. This entire support system is funded through the Public Service Obligation (PSO) levy, a charge applied to all consumers' bills. Because the KOT framework is universally applied by all electricity suppliers, RAAEY does not consider that this mechanism hinders the competition in the electricity market, although not all offers can be combined with the discount of social household prices. Eligible consumers can choose or switch their electricity provider freely without any risk of losing their social tariff benefits, which maintains a level playing field among competitors in the retail market¹⁶.

Within 2023, RAAEY has maintained continuous oversight of the evolving electricity supply prices, which are published monthly on the 20th day of the preceding month. RAAEY's actions in announcing the Tariffs of Electricity Supply per Consumer category and the "Reference Tariff" of Universal Service Supplier are in strict compliance with the provisions of Article 138 of Law 4951/2022 (Gazette A'129/04.07.2022), as amended by Article 107 of Law 4964/2022 (Gazette A'150/30.07.2022). These measures expired on 31 December 2023.

This provision serves to alleviate consumers' uncertainty by providing them with foreknowledge of the prices they will be required to pay for the upcoming month, well in advance on the 20th of the preceding month. However, due to significant market fluctuations in the past year, the proactive tariff announcements appear to have influenced Suppliers in two notable ways: First, it has led them to increase their hedging contracts as a means of safeguarding against unforeseen spikes in wholesale market prices, beyond their initial estimates at the time of the monthly price announcement. Second, it has prompted Suppliers to make conservative (often higher) price estimates, offering tariffs that encompass their expectations of wholesale price movements with a significant level of certainty. This approach may have resulted in increased profits for electricity suppliers, particularly in cases where the conservative (higher) estimate surpasses the actual costs that emerged in the market.

The following table presents the average final competitive prices of household electricity products provided by various Suppliers, covering 2023.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year Average
ZENITH	135	155	127	139	147	145	133	129	118	112	124	132	133
SOLAR ENERGY	114	151	154	145	139	129	129	131	126	126	137	162	137
ELINOIL	64	163	161	151	148	146	146	146	146	146	168	160	145
VOLTON	143	164	160	158	143	135	133	138	133	132	135	160	145
PPC	162	157	153	153	144	138	138	143	138	138	145	170	148
VOLTERRA	188	170	175	174	174	105	125	130	125	125	135	160	149
WATT & VOLT	129	205	205	155	159	155	152	141	125	123	150	151	154
NRG	134	194	192	168	143	126	139	145	160	157	150	167	156
Fysiko Aerio	134	221	220	145	142	131	130	128	136	136	146	198	156
OTE ESTATE	145	176	176	175	175	145	145	150	145	134	164	170	158

¹⁶ Additional information on social household 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/>

PROTERGIA	130	214	214	175	174	157	150	140	132	135	162	163	162
HERON	115	200	197	174	167	149	144	147	158	155	155	178	162
WE ENERGY	105	210	210	215	195	138	138	143	138	138	153	178	163
ELPEDISON	142	165	195	180	190	185	171	146	147	157	189	200	172
MONTHLY AVERAGE	131	182	181	165	160	142	141	140	138	137	151	168	153

Table 15: Average Tariffs of Household Electricity Products. 2023 (€/MWh) after the application of subsidies from the Energy Transition Fund

According to the data presented in the above table, the average monthly prices for Greece's competitive retail electricity market in 2023 show a fluctuating trend. Prices peaked early in the year, reaching a high of 182 €/MWh in February. After a slight dip in March and April, prices stabilized around 140-160 €/MWh from May to November. There was a modest increase in December, with prices rising to 168 €/MWh. Overall, the year was characterized by initial high volatility, followed by mid-year stabilization and a slight increase towards the end.

According to EUROSTAT, retail household electricity prices decreased within 2023, stopping their upward trend that was recorded in 2021, following the increase in wholesale electricity prices since the summer of 2021. Specifically, electricity prices for household consumers with an average annual consumption between 2,500 and 5,000 kWh (DC band) decreased from 0.2950 €/kWh in the first half of 2022, to 0.1876 €/kWh in the first half of 2023, reflecting a decrease of 36.4%. In the second half of 2023, prices slightly increased to 0.1905 €/kWh, a 58.2% decrease compared to 0.4556 €/kWh in the second half of 2022.

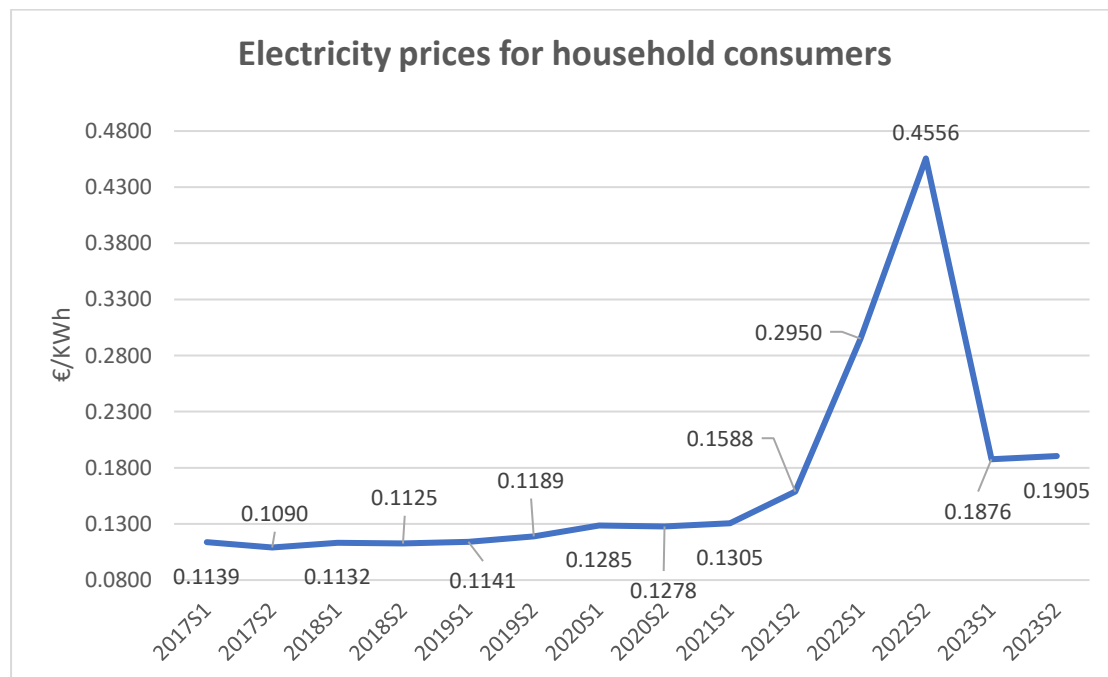


Figure 14: Electricity prices for household consumers – Eurostat (Consumption Band DC: 2,500 kWh < Consumption < 5,000 kWh) – Energy Component

Even though Figure 14 represents the prices of the retail competitive component of consumers' bills, it does not accurately reflect the final price paid by consumers. Specifically, the methodology used by EUROSTAT to calculate electricity prices for household consumers does not account for the subsidies

incorporated into consumers' energy bills, which are primarily recovered under the Temporary Mechanism applied in Day-Ahead and Intra-Day markets.¹⁷ The Household Energy Price Index (Figure 15), calculated by VaasaETT and commissioned by the Austrian energy regulator (E-Control) and the Hungarian Energy and Public Utility Regulatory Authority (MEKH), provides a more realistic reflection of electricity prices for Greek consumers.

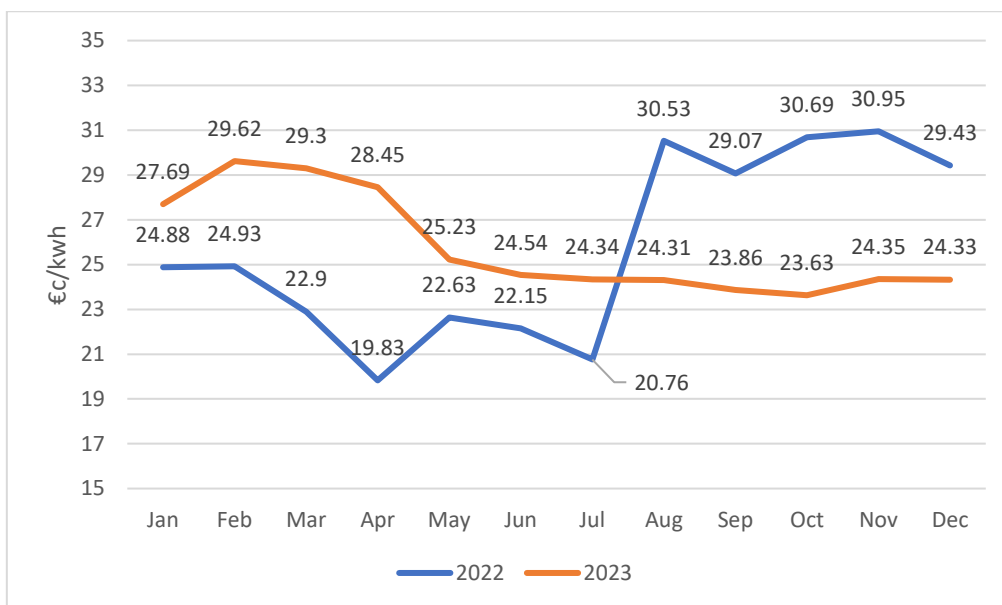


Figure 15: HEPI Index by e-Control, MEKH and VaasaETT – Total electricity price paid by consumers

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 annual electricity consumption.

The installation of smart meters was initially delayed due to legal challenges since the failed 2014 tender, was reinitiated in December 2021. Despite these setbacks, the installation of smart meters is now set to transform the Greek energy market, modernizing the grid and supporting a successful energy transition.

RAAEY has set a timeline (RAAEY Decision 525/2021) for HEDNO to reduce power theft by installing smart meters, with penalties for the distribution system operator for non-compliance. HEDNO's ongoing tender for 7.3 million low-voltage smart meters, worth €1.2 billion, aims to complete by early 2024. The number of smart meters in Greece is projected to increase to 500,000 by the end of 2023, with an additional 800,000 to 1 million meters installed annually until 2030, targeting full coverage by then.

The project's total budget is €1.2 billion, and it aims to install 7.5 million smart meters, replacing outdated analog meters. This will not only enable consumers to monitor their consumption but also allow HEDNO to detect and resolve low-voltage issues more efficiently. The first phase will deliver 500,000 meters, with the ability to remotely meter 40% of consumed energy by the end of 2023, expected to surpass 55% by the end of 2024.

On November 8, 2023, the European Investment Bank (EIB) and HEDNO signed a contract to fund the gradual installation of smart electricity meters. The two organisations signed a 15-year loan worth €150

¹⁷ See: <https://www.rae.gr/en/market-monitoring/greek-wholesale-electricity-markets/temporary-mechanism/>

million to install 3.12 million smart meters and necessary support infrastructure. This project is expected to be co-financed with an additional €273 million loan from the Recovery and Resilience Facility.

Dynamic contracts are not available in the Greek retail market due to the lack of smart meter installations and an appropriate regulatory framework. However, RAAEY aims to complete the regulatory framework for dynamic contracts by the end of 2024, after which consumers owning a smart meter will be able to enter into dynamic contracts with their suppliers.

3.2.2.4 Switching rates

The monitoring of the retail electricity market is done separately for Interconnected and Non-Interconnected System, given that the full liberalisation of electricity supply in the Non-Interconnected Islands took place only from 01.01.2018 (RAAEY Decision 908/2017, law B' 4461) and is therefore not equally mature.

Regarding supplier switching rates, according to HEDNO's data, 9.53% of LV and MV consumers in the Interconnected System switched their supplier in 2023 (equivalent to 8.86% of the total consumption in the LV and MV market). When compared to 2022, a slight increase of supplier switching was observed among both household consumers and LV-MV commercial and industrial consumers in terms of the number of connections in 2023. In terms of volume, commercial and industrial consumers continued to exhibit the highest switching trend in 2023. It is also notable that the consumed volume of household consumers that switched their supplier almost doubled in 2023, compared to 2022. In general, compared to 2022, the data showed a reversal in the trend of declining consumer connections, as the total number of connections slightly increased.

The following table includes data regarding consumer switching (LV and MV) in the Interconnected system for 2023 (data by HEDNO). For supplier switching in Non-interconnected islands, refer to chapter 3.2.4.2.

Figure 16 below illustrates LV consumer switching among all suppliers for the entire Greek electricity market (both Interconnected System and NII) in 2023, based on the number of connections.

Consumer Category	Number of Consumers in the Interconnected System in 31.12.2023	Number of consumers that switched supplier in 2023	Switching rates (% in number of consumers)	Total Consumption in 2023 (MWh)	Consumption of consumers that switched supplier in 2023 (MWh)	Switching rates (% of consumption volume)
Household consumers (not including Social Tariff)	4,893,069	527,693	10.78%	11,986,600	721,278	6.02%
Household Consumers under Social Tariff	494,733	99	0.02%	1,737,724	47,466	2.73%
Small industrial and commercial consumers	1,184,453	124,241	10.49%	9,161,892	1,222,783	13.35%
Oher LV consumers	307,165	3,848	1.25%	2,660,600	16,215	0.61%
Total LV consumers	6,879,420	655,881	9.53%	25,546,816	2,007,742	7.86%
Commercial and Industrial consumers	14,230	908	6.38%	8,813,245	1,165,998	13.23%
Oher MV consumers	1,772	10	0.56%	1,518,606	3,981	0.26%
Total MV consumers	16,002	918	5.74%	10,331,851	1,169,979	11.32%
Total number of LV and MV consumers	6,895,422	656,799	9.53%	35,878,667	3,177,721	8.86%

Table 16: Number of metering points, consumption volume and switching rates per consumer category in the interconnected system's electricity retail market in 2023

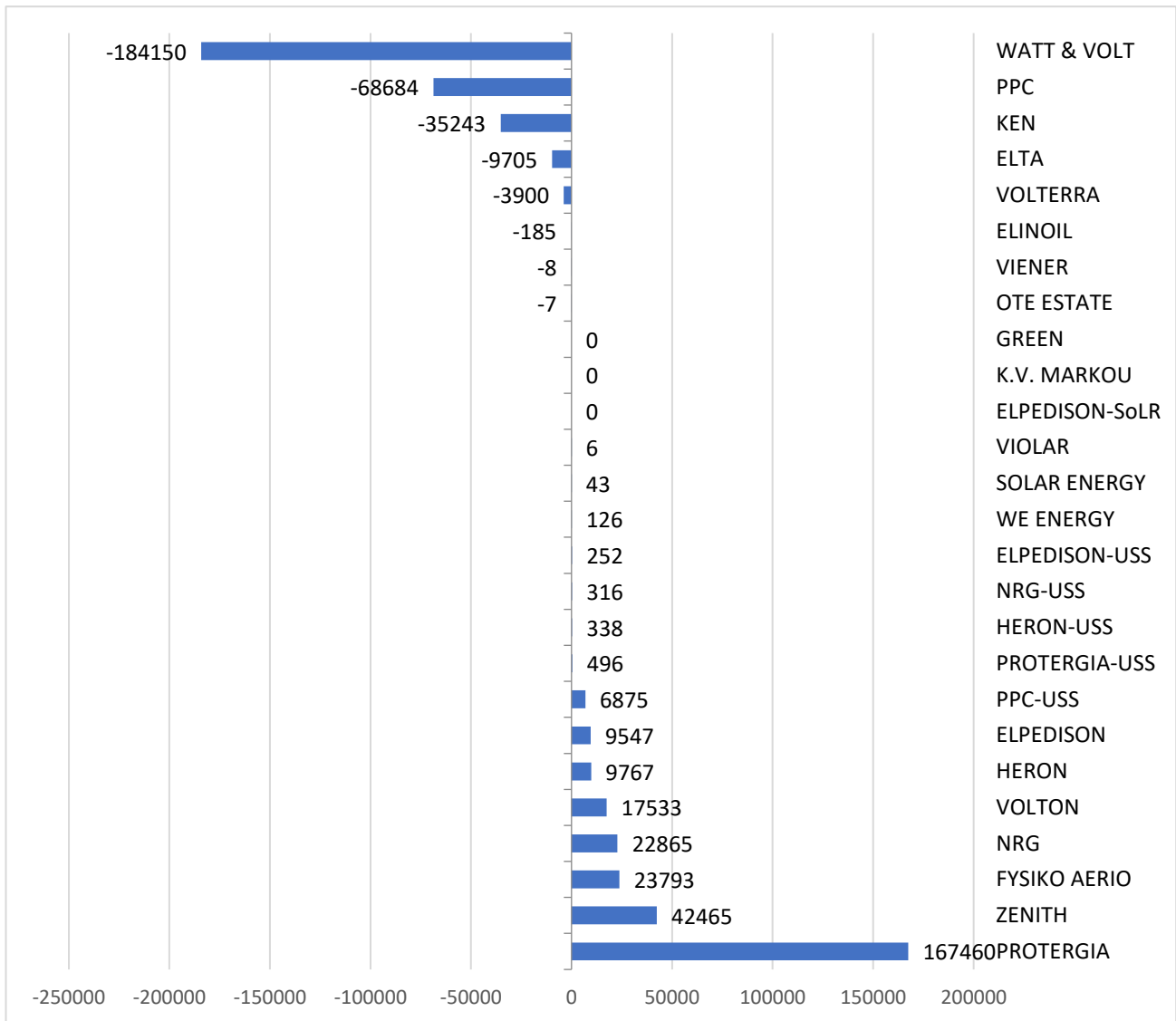


Figure 16: MV & LV consumer switching among all suppliers for the entirety of Greek electricity markets (both Interconnected System and NII) in 2023, based on the number of connections.

3.2.2.5 Relationship between household and wholesale prices

According to Article 69 1. (o) of Directive 944/2019, the NRAs have the duty to monitor the relationship between household and wholesale prices. Monitoring the relationship between household and wholesale electricity prices is important as it ensures fair pricing for consumers and reflects the true costs of energy production. Wholesale prices continuously fluctuate due to supply and demand, fuel costs, and market conditions. If household prices don't follow these changes, it can indicate inefficiencies or unfair pricing practices. Tracking this relationship also helps policymakers ensure market transparency, address affordability concerns, and promote competition. Additionally,

understanding price dynamics supports better energy planning and sustainability efforts, as it encourages shifts to renewable energy sources when they become more cost-effective.

In 2023, RAAEY conducted its own analysis of the relationship between household and wholesale electricity prices. More specifically, RAAEY calculated the Average Competitive Retail Price based on information received from suppliers about all their offers available in the market. The retail price excluded network tariffs, the RES levy, taxes, and any state subsidies aimed at alleviating the impact of high energy prices on consumers. On the other hand, the Average Weighted Market Price, which reflects the costs for suppliers to procure energy, was calculated considering the Average Day-Ahead and Intraday Market Prices, imbalance costs, network losses, as well as balancing energy and balancing capacity costs.

The analysis found that the Average Competitive Retail Price peaked in January at 461 €/MWh, while the Average Weighted Market Price was 210 €/MWh. This significant difference indicated a sharp mark-up (252 €/MWh) and substantial subsidies of 330 €/MWh, which brought the Average Competitive Retail Price (including subsidies) down to 131 €/MWh.

From February through June, both retail and wholesale prices declined. However, from July to August, wholesale prices saw a mild increase, likely due to higher electricity demand during the summer. Despite this, retail prices remained relatively stable until November. The mark-up also decreased, reaching its lowest point of 24 €/MWh in October.

Retail prices between July and October remained relatively stable compared to the volatility observed in 2022. In November and December, retail prices gradually increased. This rise cannot be attributed to wholesale price fluctuations, as wholesale prices remained relatively stable during that period.

Lastly, subsidies played a critical role in reducing retail prices, especially in January, when they reached 330 €/MWh. For most of the year, subsidies were capped at 15 €/MWh or lower, with the exception of November, when they spiked to 25 €/MWh before being completely removed in December. The government's aim was to cap final household prices at 150 €/MWh after subsidies, to mitigate the burden on consumers.

The mark-up, representing the difference between retail and wholesale prices, peaked in January at 252 €/MWh but dropping to 24 €/MWh in October, and ending at 50 €/MWh in December. The yearly average mark-up was 65 €/MWh.

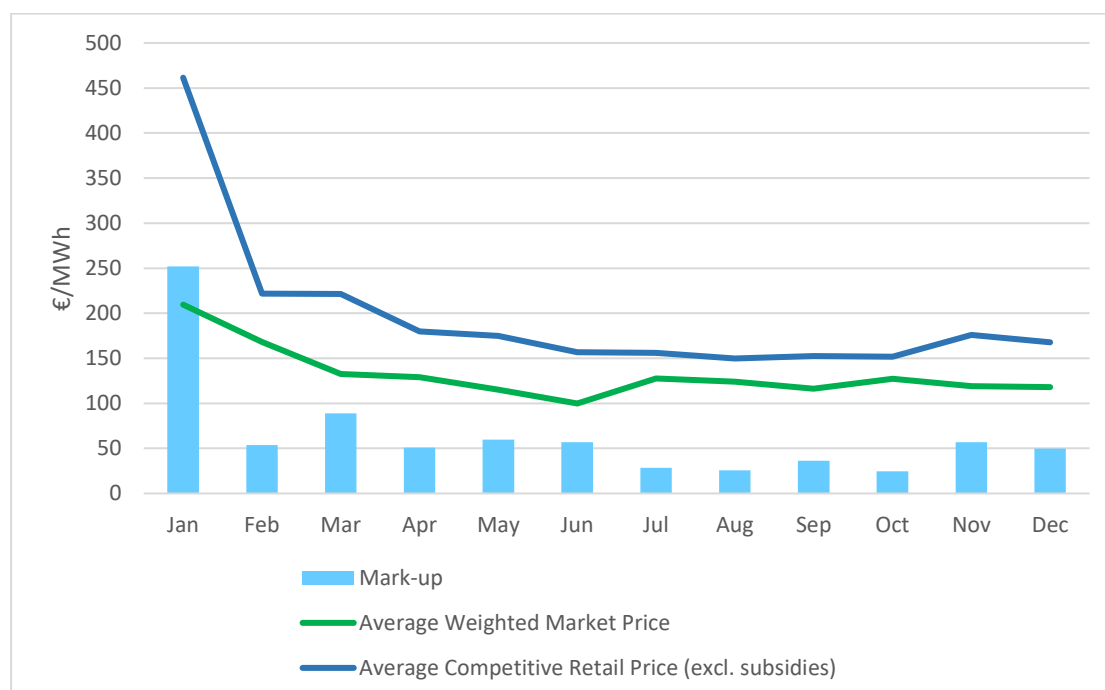


Figure 17: Correlation between wholesale and retail electricity prices in €/MWh (2023) – RAAEY analysis

3.2.2.6 Distortion and restriction of competition

In 2023, RAAEY did not detect any significant issues related to distortion or restriction of competition in the electricity market. While previous concerns arose in 2022 regarding misleading advertising and unilateral amendments to supply contracts, no such issues were identified during 2023. In 2022, some suppliers misrepresented state subsidies as their own commercial discounts, potentially distorting competition. RAAEY responded by issuing warnings and requiring suppliers to withdraw misleading advertisements. It also provided guidelines to improve transparency, especially regarding the presentation of supply charges and state subsidies. Additionally, RAAEY continued to monitor suppliers for compliance with the Electricity Supply Code, particularly regarding the unilateral modification of supply contracts. However, no significant violations were reported in 2023, and RAAEY remains committed to ensuring fair competition and consumer protection in the market.

3.2.2.7 Consumers' Protection

In 2022, RAAEY received a substantial number of consumer complaints from electricity and gas consumers. However, during 2023, there was a notable decrease in the number of complaints, likely due to lower final retail consumer prices recorded throughout the year. The majority of complaints continued to be processed through the "MyRae" online platform, which was launched in September 2021 and further improved in 2022 to streamline submission and investigation processes. This advanced information system automatically directs each report to the relevant recipient while providing RAAEY with comprehensive tracking and detailed information.

In 2023, a total of 6,075 consumer complaints were submitted via the "MyRae" platform, with 4,970 related to electricity and 1,050 to gas. The breakdown of these complaints by recipient is depicted in the figures below.

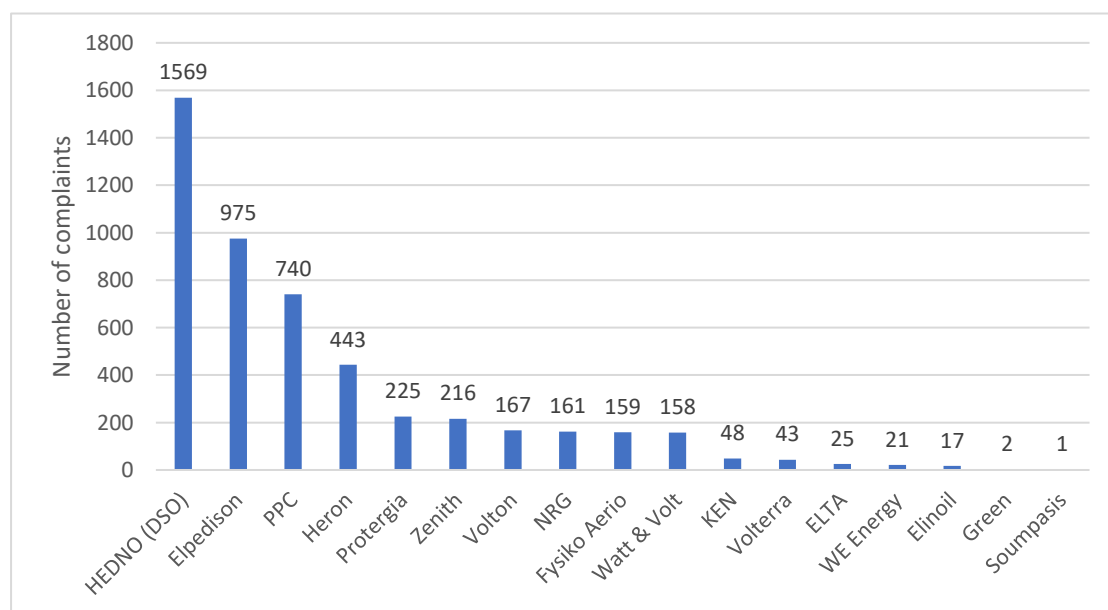


Figure 18: Complaints submitted to MyRAE platform per electricity supplier (2023)

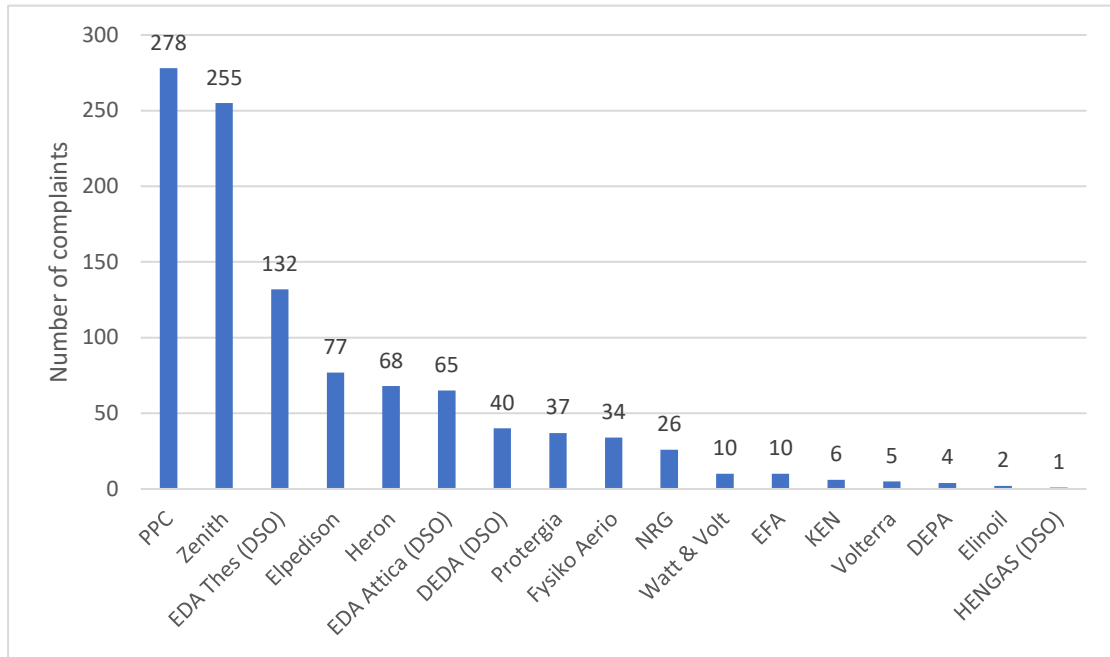


Figure 19: Complaints submitted to MyRAE platform per gas supplier (2023)

To offer a balanced perspective on the challenges faced by each supplier, considering their consumer market share, in 2018, RAAEY introduced a weighted index for the number of consumer complaints per supplier, based on the market share of each supply company and the number of complaints received by the company and in total. Figure 20 represents the results of the Weighted Complaint Index (WCI) per Supplier for 2023. RAAEY applies the following formula:

$$\text{Calculation methodology: WCI} = \frac{\frac{\text{Number of complaints received by the supplier}}{\text{Total Number of complaints received by all suppliers}}}{\frac{\text{Number of supplier's consumers}}{\text{Total number of consumers active in the market}}}$$

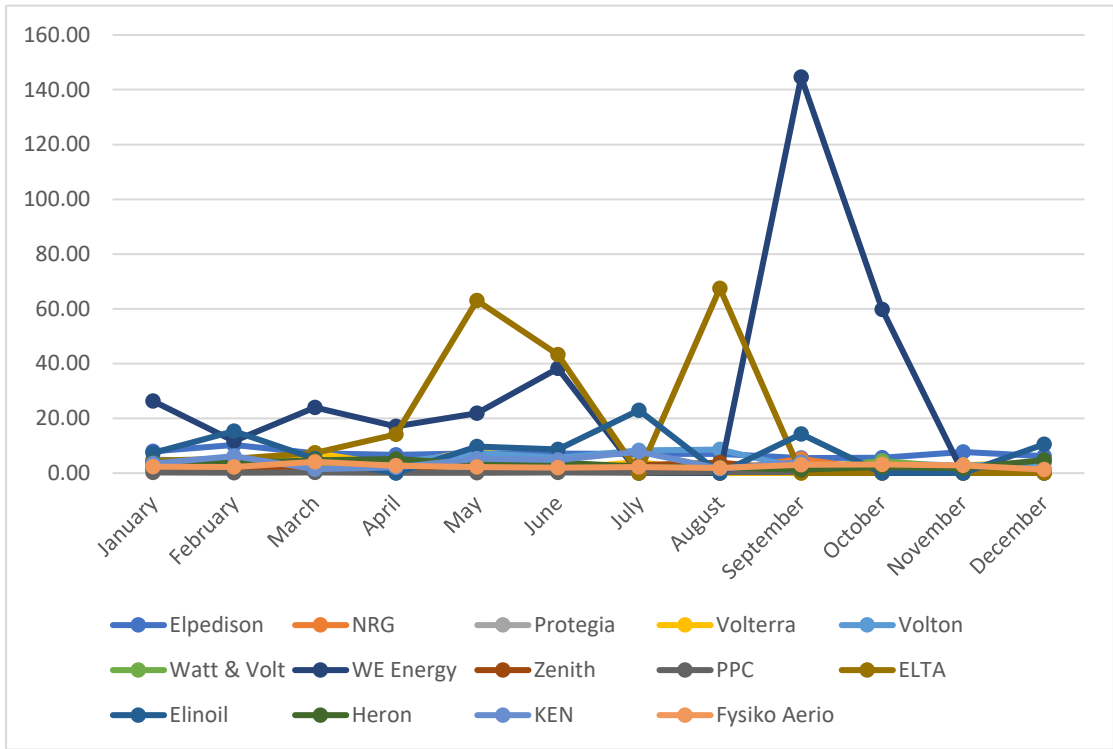


Figure 20: Electricity Weighted Complaint Index (2023)

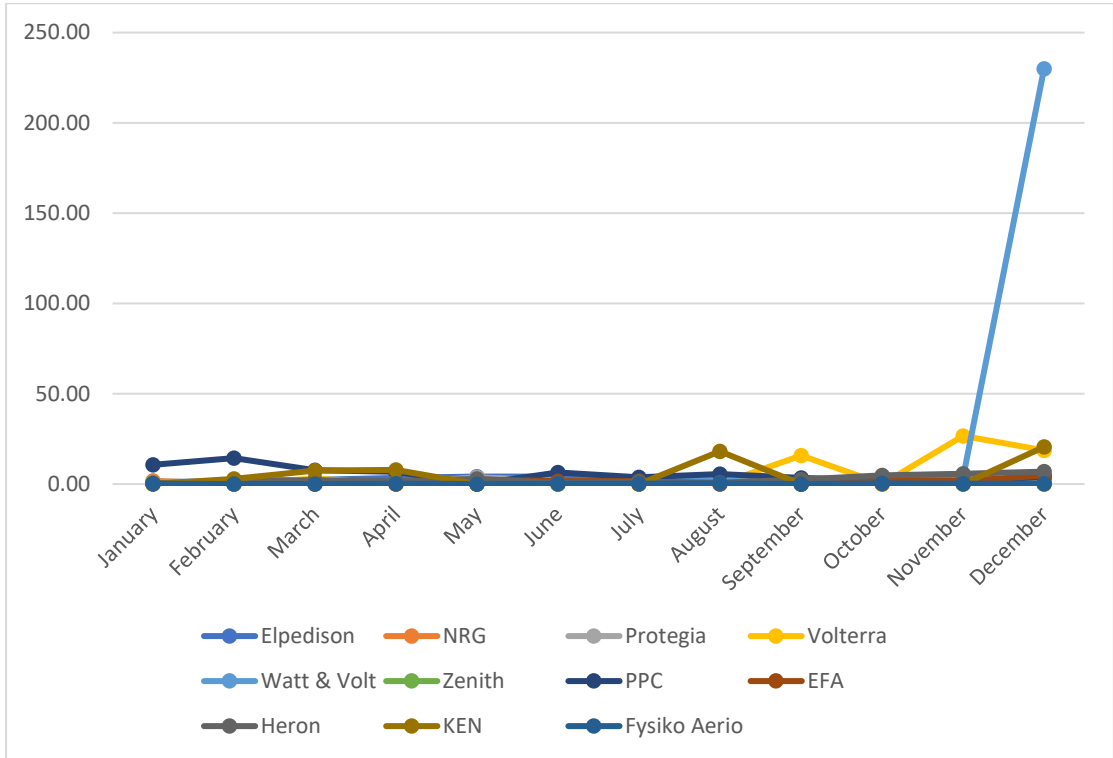


Figure 21: Natural Gas Weighted Complaint Index (2023)

In addition to the 6,020 complaints registered on the "MyRae" platform, the Authority received an additional 267 complaints in 2023 through email as well as conventional mail, while the phone call

center received 3,514 calls related to consumers' complaints, bringing the total number of complaints received by the Authority in 2023 to 9,801.

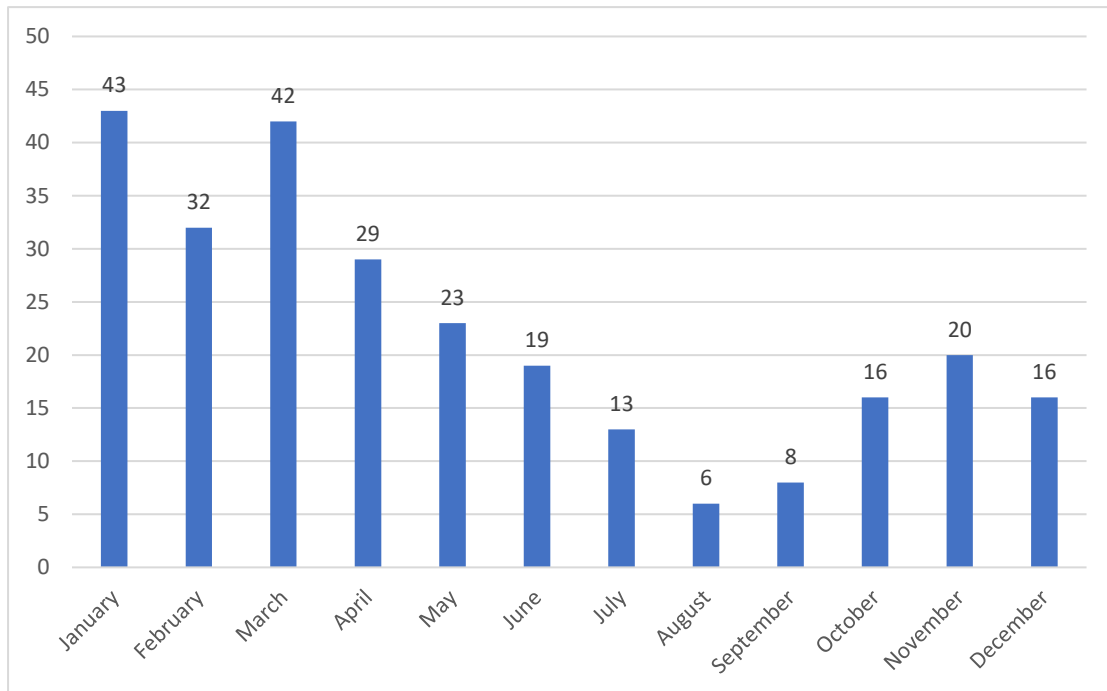


Figure 22: Complaints submitted to RAAEY outside MyRAE online platform (2023)

3.2.2.8 Other retail market topics

Providing guidelines and setting obligations to electricity suppliers regarding the transitioning to a new retail regime

The Regulatory Authority for Energy, Waste, and Water, in light of the introduction of a new structure in the retail market, issued Decision E-160/2023 which outlines a comprehensive set of obligations for electricity suppliers, primarily focusing on notification procedures and contract amendments to safeguard consumer rights and enhance transparency. The decision mandates that suppliers provide timely and detailed advance notice of any changes to electricity supply contracts effective from 1 January 2024 that are a result from the transition into the new structure. This advance notice must be delivered to customers by 1 November 2023, and suppliers bear the burden of proof for meeting this deadline. Importantly, if no modifications are made to existing contracts, suppliers are not required to notify customers, with billing continuing under the terms of the signed contracts.

The decision also addresses the process of handling expiring contracts or discontinued products, requiring suppliers to notify customers in such cases. Specifically, if a contract is set to expire and no new agreement is reached, or if a product is discontinued after 1 January 2024, suppliers must inform customers about their transition to a new product or contract that corresponds to their consumer category. The same advance notice deadline of 1 November 2023 applies, and if customers do not object within 30 days of receiving the notice, their consent to the new terms is presumed. However, customers can opt out by notifying the supplier in writing. If no new contract is signed before the expiry of the current arrangement, customers will be moved to the default offer of the Universal Service Supplier.

Additionally, suppliers must ensure that the content of their supply contracts is transparent, fair, and easily accessible to customers. This includes clearly stating both general and specific terms, detailing the methodology used to calculate charges, and posting all contract terms online, along with historical information of contracts from the past three years. The decision also sets rules for variable pricing products, requiring suppliers to publish the final consumer prices based on wholesale market fluctuations either before or shortly after the consumption period. Variable pricing products must not include additional price adjustment mechanisms beyond those linked to market indices.

A key element of the decision is the introduction of transparency markings for different types of electricity products. Fixed-price products will be labeled with a blue marking, variable pricing products with a green marking, and dynamic pricing products—those reflecting real-time wholesale market prices—with an orange marking. This labeling system aims to help consumers quickly understand the pricing structure of the products they are being offered.

Overall, the decision aims to ensure that electricity suppliers operate with greater transparency and accountability, providing consumers with the information they need to make informed decisions about their electricity supply.

Monitoring suppliers' outstanding debts to the operators

RAAEY continued the implementation of the "Positive Reporting" initiative in 2023, which had been launched in March 2022. As part of this initiative, details of suppliers who comply with their obligation to pay both Regulated and Non-Regulated Charges to the operators were made public. These suppliers are categorized as follows:

- Category A: Suppliers with no outstanding debt.
- Category B: Suppliers with outstanding debts that are fully settled, covered by guarantees, and where the agreed installment payments are duly made.

As of December 2022, the total overdue Regulated Charges owed by suppliers to the operators amounted to €39,339,463.09, while the total overdue debts (including both Regulated and Non-Regulated Charges) reached €55,877,672.

By December 2023, the total overdue Regulated Charges had decreased significantly to €10,083,645.61, and the total overdue debts (Regulated and Non-Regulated Charges) fell to €11,762,411.43. This represents a substantial reduction of approximately 79% in debts from December 2022 to December 2023, following the implementation of the "Positive Reporting" initiative by RAAEY.

Increasing transparency in the retail markets

In 2023, RAAEY issued comprehensive guidelines to electricity suppliers to ensure compliance with Article 138 of Law 4951/2022. This article introduced transitional measures in electricity supply to mitigate the economic impact of the energy crisis. Among its key provisions, the article prohibited variable electricity supply tariffs by denying the suppliers to include adjustment clauses or mechanisms linked to wholesale market fluctuations between August 1, 2022, and July 1, 2023. This period could be extended or terminated earlier by decision of the Minister of Environment and Energy, provided the Temporary Mechanism for the Partial Return of Income from the Day-Ahead & Intra-Day Markets under Article 12A of Law 4425/2016 was in place.

Suppliers were required to announce, by the 20th day of each month, the fixed charges, energy supply tariffs, and discounts for the following month. These details had to be prominently displayed on their websites, ensuring transparency. Customers with specialized tariff agreements negotiated with suppliers also had to be informed individually, in line with the Electricity Supply Code (B' 832/2013). For universal service suppliers, tariffs were based on the highest electricity supply tariff price within a 0–2 MWh consumption scale, as determined by RAAEY and published monthly. The universal service tariff was calculated by adding 5% to the Reference Tariff, with adjustments allowed only under strict conditions.

RAAEY stressed that compliance with these guidelines was essential for market transparency, healthy competition, and consumer protection. Timely tariff announcements ensured that suppliers presented their policies simultaneously, preventing unfair practices or last-minute adjustments that could distort competition. These deadlines also enabled consumers to compare offers and make informed decisions. RAAEY warned that non-compliance would infringe the law, restrict consumer choice, and distort market fairness. Instances of violations were being investigated, with potential sanctions under Article 36 of Law 4001/2011.

To enforce compliance, RAAEY implemented a procedural framework. Suppliers must notify RAAEY of their prices and terms for the upcoming month by 23:59 on the 20th day of each month. These details must also be published on their websites by 24:00 the same day. By 10:00 on the 21st day, RAAEY publishes a consolidated list of products and prices on its website. Any products not submitted or published on time are excluded from announcements and the government's consumer platform e-katanalotis.gov.gr. Furthermore, suppliers are prohibited from modifying their prices or introducing new products for the following month after the 20th day's deadline.

This structured approach by RAAEY aims to ensure compliance, foster competition, and empower consumers in the electricity market.

RAAEY's Opinion on Amendments to the Electricity Supply Code to Align with Directive (EU) 2019/944

RAAEY provided recommendations to the Minister of Environment and Energy for amending the Electricity Supply Code (Government Gazette B' 832/09.04.2013) to effectively incorporate provisions of Directive (EU) 2019/944, which were not fully transposed into Greek law via Law 4986/2022. Key proposed changes address supply tariffs, contractual obligations, customer rights, and billing transparency.

Supply Tariffs and Contractual Provisions

Article 11: Suppliers must present tariffs clearly to facilitate customer comparison.

Article 18 and Article 29: Supply contracts must provide detailed terms, including obligations to inform customers about their right to switch suppliers and the conditions for imposing termination fees. Suppliers may charge termination fees for fixed-price, fixed-term contracts terminated early, provided the fee is proportionate, pre-disclosed, and based on the supplier's direct economic loss. Additionally, suppliers must inform customers of the option to adopt advanced metering systems for better tracking and billing of electricity usage.

Suppliers are also obligated to include information in bills or supplementary documents about their energy mix, CO2 emissions, and environmental impact from electricity generation. They may refuse to serve customers with substantial outstanding debts to other suppliers, with such conditions clearly defined in the supply agreement.

Customer Service and Billing Transparency

Article 31: Suppliers must respond promptly to customer complaints and requests for clarification, particularly if bills are not based on actual consumption.

Article 37: Bills must contain accurate, comprehensible, and easily comparable pricing information. Customers should receive clear explanations of charges upon request, especially if estimates or flat-rate calculations are used. Bills must be issued in the customer's preferred format (paper or electronic) and must allow flexible payment options, including bank transfers, credit or debit cards, and payments at supplier-authorized locations.

For customers with smart meters, suppliers are required to provide accurate consumption-based billing monthly and make the consumption data accessible online. Customers without remote-reading meters may manually report their usage to suppliers every six months or quarterly to avoid reliance on estimated charges.

Bills must also reference RAAEY's online tools for complaints and price comparison (my.rae.gr and energycost.gr). Suppliers must inform customers about options to switch suppliers, benefits of alternative tariffs, and any upcoming price or product changes, including their effective dates.

Metering and Customer Rights

Article 41: Suppliers must ensure accurate consumption measurements for conventional meters and provide accessible tools for customers to read their own meters. Advanced metering options must be available to enable more precise billing based on actual consumption and usage patterns.

Additional Obligations

Suppliers must provide:

- Free and prompt explanations of billing calculations.
- Information about out-of-court dispute resolution mechanisms, including relevant contact details.
- Transparency on network charges through advanced metering systems that separately measure electricity supplied and consumed.

These proposed amendments aim to enhance customer protections, promote transparency, and align Greek regulations with EU energy directives.

3.2.3 Renewable energy sources and HECHP

3.2.3.1 RES and HECHP installed capacity and generation

The installed capacity of Renewable Energy Sources' (RES) power plants at the end of 2023 amounted to 12,040 MW, showing an increase of approximately 16.45% compared to that recorded at the end of 2022 (10,339 MW). As in 2022, 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 1,182 MW within 2023. Table 17 presents the total capacity distribution per renewable technology. In 2023, RES and HECHP production in Greece amounted to 21 TWh in total, which was increased compared to 19.22 TWh in 2022. Table 18 presents the electricity production of RES units per technology between 2020 and 2023.

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 years, mainly in the field of solar PVs. Furthermore, this trend is expected to be strengthened over the next years due to the provision of operating aid to new power parks which were successful in the competitive tender procedures held by RAAEY since 2018, but also due to the improved economic and investment climate in the country.

In addition, following the Russian aggression against Ukraine in February 2022, Greece is increasingly gaining further momentum in the renewable energy sector as part of the European Commission's REPowerEU plan. This comprehensive plan is designed to reduce the EU's dependence on Russian fossil fuels and enhance the resilience of the European energy system. Greece's commitment to this initiative is evident in its pursuit of funding support, estimated at 7 to 8 billion euros, for approximately 14 energy efficiency and security projects through the REPowerEU initiative. The country is consistently looking to leverage various European funding programs, including the National Strategic Reference Framework (NSRF), the Recovery and Resilience Facility (RRF), and the European Solar Rooftop Initiative, to accelerate its transition towards renewable energy sources.

RES Technology	Installed Capacity in 2020 (MW)	Installed Capacity in 2021 (MW)	Installed Capacity in 2022 (MW)	Installed Capacity in 2023 (MW)	% change 2022-2023
Wind	4,119	4,456	4,570	5,056	10.63%
PV	2,860	3,660	4,895	6,077	24.15%
PV on roof (P < 10 kW)	375	375	375	376	0.27%
Hydro Small (P < 15 MW)	245	251	263	277	5.32%
Biomass - Biogas	97	109	113	123	8.85%
Hybrid RES	3	3	3	3	0.00%
HECHP	235	237	120	128	6.67%
Total RES	7,699	8,854	10,219	11,912	16.57%
Total RES & HECHP	7,935	9,091	10,339	12,040	16.45%

Table 17: Total RES/HECHP installed capacity and percentage change (2020-2023)

	2020	2021	2022	2023
Wind	9,323	10,503	10,668	11,022

PV	3,898	4,679	6,582	7,936
PV on roof (<10kW)	494	467	465	461
Small hydro	541	679	630	690
Biomass-Biogas	429	452	691	565
Hybrid RES	3	4	5	6
HECHP	1,102	216	181	322
Total RES*	14,685	16,780	19,036	20,674
Total RES, Hybrid RES & HECHP*	15,790	17,000	19,222	21,002
*Excluding large hydroelectric power parks (>15 MW)				

Table 18: Total RES/HECHP generation in GWh (2020-2023)

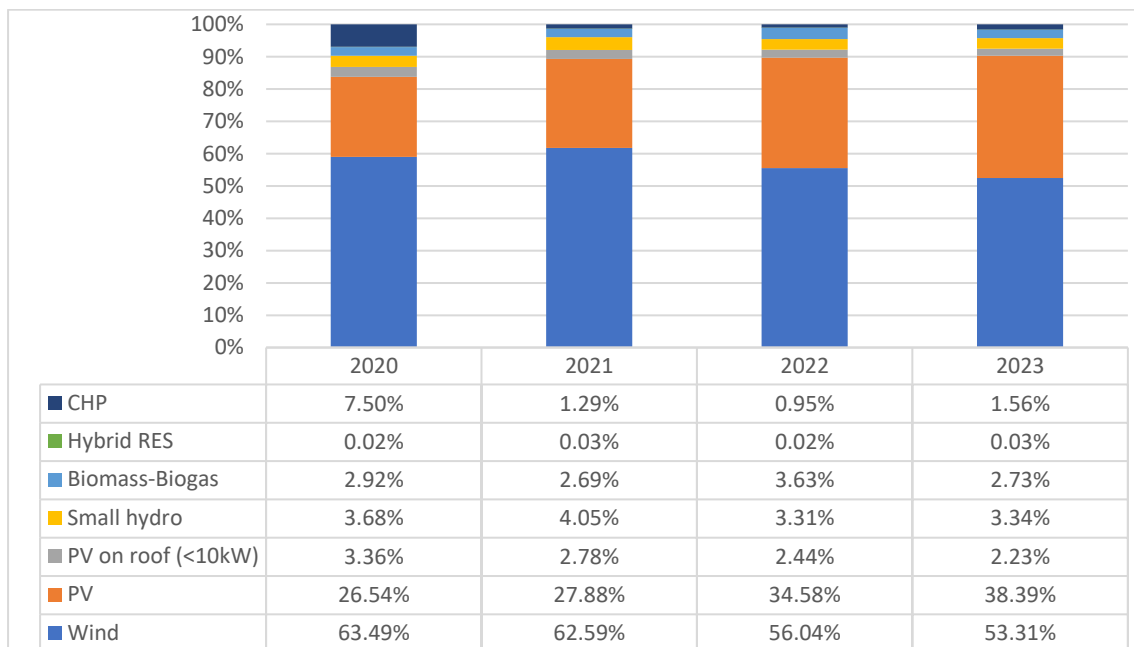


Figure 23: RES/CHP Generation percentage excluding large hydroelectric plants per technology (2020-2023)

3.2.3.2 RES and the electricity market

In Greece, balancing responsibilities for Renewable Energy Sources (RES) and High-Efficiency Cogeneration of Heat and Power (HECHP) plants are crucial for maintaining grid stability, especially considering the evolving market landscape in 2023. Since November 1, 2019, RES and HECHP power parks compensated under the Feed-in-Premium (FiP) scheme had taken on partial balancing responsibilities through the Transitory Mechanism for Optimal Forecasting Accuracy (TMOFA). Under TMOFA, these power parks were required to provide accurate forecasts of their electricity production and to minimize deviations in supply and demand.

Additionally, RES and HECHP installations with a capacity equal to or greater than 400 kW that receive feed-in tariffs and commenced operations after July 4, 2019, assume partial balancing responsibilities for their load. These balancing responsibilities are also assumed by RES aggregators and the Aggregator of the Last Resort (DAPEEP) for the plants they represent in the wholesale electricity markets.

From December 2022, following the introduction of the Intraday Continuous Trading Market (XBID) in Greece, RES projects that operated previously under the Transitory Mechanism for Balancing and Settlement Accuracy (TMOFA) resumed full balancing responsibilities. In particular, the TMOFA mechanism remained in effect until November 29, 2022. From November 30, 2022, with the coupled operation of the Intraday Markets under the cross-border intraday project (XBID), RES and HECHP power plants compensated under FiP and FiT¹⁸ contracts, or their aggregators, assumed full balancing responsibilities. This change underscored the growing importance of accurate forecasting and active market participation to stabilize the electricity grid and optimize the integration of renewable energy sources into the market.

Furthermore, the Temporary Mechanism for Day-Ahead and Intraday market for windfall profits in the electricity sector that was introduced with Article 122 of Law 4951/2022 expired on December 31, 2023.

Law 4001/2011 outlines the responsibilities of the DAPEEP S.A., in collecting revenue from contracting RES and HECHP producers to cover its operational expenses and investment costs. The operator submits an annual budget to the Ministry of Energy for approval, detailing expected costs and reasonable profit. In 2023, DAPEEP S.A. recommended a Unit Charge for RES and HECHP Producers ("UOCC") for 2024, which was approved at 0.442 €/MWh. The approved budget for 2024 is €12,980,724 while the estimated RES and HECHP energy production for 2024 is 23,000,000 MWh. In this regard, RAAEY approved a reduced UOCC charge, considering increased RES electricity production from RES and HECHP.

3.2.3.3 RES projects' licensing

The dynamics of the Renewable Energy Sources (RES) market in 2023 remained robust, building upon the positive momentum of 2022. Notably, the installation rate of photovoltaic power parks saw a remarkable surge, continuing the upward trend from the previous year. In particular, photovoltaic projects in the licensing process experienced significant growth, with installed capacity increasing from 63 GW to 68 GW. However, the RES units under operating licenses expanded at a more moderate pace, rising from 5,416 MW to 5,772 MW in 2023.

Within 2023 PAAEY issued a total of 23,499 administrative acts as part of the licensing evaluation process. The total number of licenses and the number of RAAEY decisions per category in 2023 is presented in the tables below.

¹⁸ Power plants with a capacity equal to or greater than 400 kW that receive compensation from feed-in tariffs and began operations after July 4, 2019.

Type of Decision	Number
New applications for Production certificates	463
Decisions on application rejection for Production certificates/Production licenses	97
Decisions on Production certificates modification / transfer	1,413
Production certificates granted due to modification or transfer of the Production license	162
Automatic termination due to forfeiture of the letters of guarantees	247
Automatic termination due to the return of the tender fees	0
Automatic termination of licenses due to failure to meet implementation deadlines	10
Decisions on Production certificate revocations	5
Decisions on modification requests	5
Decisions to register a polygon of exempted parks	20,633
Electricity storage licenses granted	464
Total	23,499

Table 19: RAAEY licensing activity in 2023

Revocations / End of duration/ Termination of licenses														
	Wind		Photovoltaics		Small Hydro		Biomass		CSP		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)	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 (Art. 12 (2) of L. 4685/2020)	3	64.70	7	317.46									10	382.16
Termination of licenses of wind parks that are not included in the area of offshore wind parks (Art. 174 (15) of L. 4964/2022)	1	498.15											1	498.15
Termination of licenses due to non-submission of the financial guarantee for the project implementation (Art. 11A of L. 4685/2020)	2	27.50	43	328.53	3	21.74	1	2.99					49	380.76
Termination of licenses due to unbundling of project from the special interconnection project named Polypotamos – N. Makri (Art. 102 (2) of L. 4951/2022)	3	31											3	31
Termination of licenses due to a voluntary application. (Art. 31 (2d) of L. 4951/2022)	4	78.60											4	78.6
Termination of licenses due to non-submission of the second instalment of the fee for issuing a Producer's Certificate	11	32.16	2	27.99									13	60.15
Termination of licenses due to submission of an irrevocable application to return the financial guarantee for the project implementation (Art. 11A (5) of L. 4685/2020)	88	1,685.92	54	2,064.31	13	80.17	1	5	1	2	41	270.36	198	4,107.76
Voluntary revocations	2	51.90	3	43.69									5	95.59
Termination due to license duration expiry without submitting a renewal request	1	6.60											1	6.6

Table 20: Revoked RES licenses per technology (2023)

Licensing progress of RES projects										
Licensing Stage →	Operating License		Installation License		Approved Environmental Terms		Production License		Total Production Licenses/Certificates	
Technology ↓	Number of parks	Installed capacity (MW)	Number of parks	Installed capacity (MW)	Number of parks	Installed capacity (MW)	Number of parks	Installed capacity (MW)	Number of parks	Installed capacity (MW)
Wind	359	4,481.2	123	2,029.2	382	6,115.9	1,211	21,699.4	2,075	34,325.6
PV	285	960.2	164	3,100.6	1,310	29,466.8	1,030	35,615.6	2,789	69,143.2
Small hydro	131	250.6	48	111.3	69	151.7	433	557.8	681	1,071.4
Biomass	16	78.7	10	35.3	15	61.2	25	70.4	66	245.6
Geothermal	0	0	0	0	1	8	0	0	1	8.0
Hybrid RES	1	1	3	17.9	65	341.1	94	451.9	163	811.9
CSP	0	0	1	52	34	84.5	1	70	36	206.5
Total RES Projects	792	5,771.6	349	5,346.4	1,876	36,229.2	2,794	58,465.0	5,811	105,812.1

Table 21: Licensing progress of RES projects (2023)

3.2.3.4 Electricity storage licensing

In 2023, the licensing of energy storage facilities, including battery storage and hydro pumped storage, continued under a framework similar to that used for thermal power parks, with 16 electricity production licenses integrating storage technologies being granted. This followed significant changes introduced in July 2022 with the enactment of Law 4951/2022, which established a specialized licensing framework for standalone electricity storage technologies. The new law, supplemented by the Electricity Production and Supply Licensing Regulation, allowed licensees with combined renewable energy sources (RES) and storage technologies to transition their licenses into the new regulatory framework. Transitional provisions provided a three-month window for license holders to submit the necessary documentation to update their Production License to an Electricity Storage License. Additionally, projects that had applied for production licenses incorporating storage technologies but had not yet been issued were given the opportunity to obtain a Storage License.

	Number of licenses	Peak Output Capacity (MW)	Maximum Charging Rate (MW)	Storage Capacity (MWh)	Guaranteed Capacity (MWh)
Battery storage	16	940.73	940.73	2,128.28	19,41.52
Hydro-pumped storage	0	0	0	0	0
Total	16	940.73	940.73	2,128.28	19,41.52

Table 22: Production licenses issued to storage technologies within 2023

3.2.3.5 RES financial Support Scheme

The foundation of the current financial support scheme dates back to 2016.¹⁹ The main objective of this RES support mechanism is to achieve an efficient integration of renewables' generation into the electricity market.

Drawing on the experience from the 2018-2020 auction period, Greece has introduced several changes to the RES scheme for the period 2021-2025 to enhance competition, prevent collusion and strategic bidding, and ensure transparency in the tendering processes. The new scheme aims to create a more competitive and efficient market for renewable energy sources by modifying the design of the previous tender scheme.

One of the significant changes involves adjusting the capacity limits for eligible RES technologies, particularly photovoltaic (PV) and wind energy. Greece plans to gradually lower the capacity thresholds for these technologies, setting them below the levels outlined in the Guidelines on State aid for environmental protection and energy 2014-2020 ("EEAG"). By 1 January 2023, these lower thresholds will result in the obligation to participate in a tendering procedure. This change is intended to stimulate greater market interest and foster competition through a more cost-efficient approach. Additionally, Greece plans to shift the scheme's core design towards joint tendering procedures for PV and wind projects, instead of technology-specific auctions. Furthermore, all PV power plants will be obligated to participate in competitive tenders to receive operating aid from 2025, except for rooftop photovoltaics.

¹⁹ The current financial support scheme was approved by the European Commission in 2023 (SA.64736). https://ec.europa.eu/competition/state_aid/cases1/202220/SA_60064_004CB280-0000-C964-AF2C-2FDF5DDCA3CB_50_1.pdf.

This approach aims to support more cost-efficient RES projects while ensuring a diversified electricity mix and the growth of small-scale RES capacities.

The updated scheme introduces several types of support through different tendering procedures. These include joint calls for tenders for PV and wind energy, as well as dedicated joint calls for specific contexts, such as tenders for PV and wind with storage capacity, projects located on the islands of Crete, Euboea, and Cyclades, and foreign projects outside of Greece. Additionally, technology-specific tenders will be held for small-scale PV and wind projects. The scheme also includes provisions for supporting technologies exempted from tendering procedures.

	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 $60kW \leq P_{WIND} \leq 6MW$	89
1c	Wind energy utilized with onshore Wind parks that fall under the scope of the provisions of RAAEY's decision No. 904/2011, as amended by the decisions of RAAEY No. 155/2012 (Gazette B' 908) and 452/2015 (Government 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 generation 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 RAAEY.	65
1d	Small Wind parks with installed capacity $P_{WIND} \leq 60kW$	157
2	Wind Energy produced by onshore installations with an installed capacity $60kW \leq P_{WIND} \leq 6MW$, belonging to Energy Communities.	90
3	Small hydropower $P \leq 3MW$	90
4	Small hydropower $3MW < P \leq 15$ MW	87
5*	Biomass (or bioliquids) from thermal processing $P \leq 1MW$ (excluding the biodegradable fraction of urban waste)	176
6*	Biomass (or bioliquids) through gasification $P \leq 1MW$ (excluding the biodegradable fraction of urban waste)	185
7*	Biomass (or bioliquids) from thermal processing (including gasification) $1MW < P \leq 5MW$ (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 $P \leq 2MW$	123
10	Landfill gas and biogas from anaerobic digestion of the biodegradable fraction of urban waste $P > 2MW$	99
11a*	Biogas released from anaerobic digestion of biomass (energy crops, rural waste and residues, etc.) $P \leq 1MW$	219
11b*	Biogas released from anaerobic digestion of biomass (energy crops, rural waste and residues, etc.) between $1MW \leq P \leq 3MW$	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 $P \leq 5MW$	134
16	Geothermal power $P > 5MW$	104
17	Other renewable energy technologies	88
29a	Solar energy utilized with photovoltaic parks with an installed power $\leq 200kW$	63
29b	Solar energy utilized with photovoltaic parks with an installed power $200kW \leq PPV \leq 500kW$	63

	Renewable technologies and project categories	RT (€/MWh)
30a	Solar energy utilized with photovoltaic parks that belong to energy communities with an installed power PPV ≤ 200kW	65
30c	Solar energy that is utilized by photovoltaic power parks 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 parks with installed capacity ≤6kW, connected to a home power supply use and belong to natural persons not tradesmen	87
32 ²⁰	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.	<p>1-10 years of operation: -1.4 x Years of Operation + 70 11</p> <p>16 years of operation: -0.9 x Years of Operation + 61</p> <p>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</p>
37	Solar energy utilized with Pilot Offshore floating solar systems	159
	Solar PV ≥ 0.5MW	Competitive bidding
*The under commercial operation power plants of categories 5, 6, 7, 8, 11, 12 had their Reference Tariffs increased by 25% from April 2023 to March 2024 according to Article 151 of Law 5037/2023 (Gazette A' 78/2023)		

Table 23: Administrative reference tariffs for RE projects of Law 4414/2016, Table 1 of Article 4.1(b)

High Efficiency Combined Heat and Power parks (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

²⁰ 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.

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 parks	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 parks	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 YA 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 YA 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 24: 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 Β', 889/2012)

η_{th} : Thermal efficiency of cogeneration unit, as specified in Ministerial Decision Δ5-ΗΛ/Γ/Φ1/749/21.3.2012 (Gazette Β', 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

n_{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 Β', 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 monthly. 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 23 and 24.

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 **Sliding Feed in Premium** (FiP) 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 Reference Tariff (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 by RES and HECHP plants under Article 10 of the Law 4414/2016, and which is defined per RES and HECHP power park technology and category, or per RES or HECHP power park, in case this results from a competitive process, 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 RAAEY. 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 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, since 2023, is conducted in one phase: online submission of the applications’ supporting documents and submission of bids (single – step static auction).

In accordance with RAAEY Opinion 17/2022, Ministerial Decision YΠEN/ΔΑΠΕΕΚ/53607/1559 (Gazette B 3328/19.05.2022) was issued. In the decision by the Minister of Environment and Energy, several crucial aspects concerning competitive bidding procedures were established. These aspects encompass the minimum number of annual competitive bidding procedures, the installed capacity per technology and/or power park category for Renewable Energy Sources (RES) and Combined Heat and Power (HECHP) projects subject to competitive bidding, the maximum allowable bid price, the participation fee, and other matters relevant to competitive bidding procedures.

Table 25 summarizes the estimated date, technologies and auctioned capacities of RES auctions planned for 2022 – 2024, while Table 26 presents the RES auction participation fee collected by RAAEY according to the same Ministerial Decision. Despite the above decision, no RES auctions were held in Greece in 2023.

Date	Type of auction	Eligible technologies	Categories of power parks	Total auctioned capacity (MW)
2022 – Q3	Common	PV and Wind	Wind parks with capacity $P_{WIND} > 6 \text{ MW}$	1,000
			Wind parks with a capacity of $60\text{kW} \leq P_{WIND} \leq 6\text{MW}$ that do not fulfill the criterion of Article 7 (3) of Law 4414 (A' 149)	
			PV power parks with a capacity of $P_{pv} > 1\text{MW}$	
2023 – Q3	Common	PV and Wind	Wind parks with capacity $P_{WIND} > 6 \text{ MW}$	1,200 + any remaining capacity from the previous common competitive procedure
			Wind parks with a capacity of $60\text{kW} \leq P_{WIND} \leq 6\text{MW}$ that do not fulfill the criterion of Article 7 (3) of Law 4414 (A' 149)	
			PV power parks with a capacity of $P_{pv} > 1\text{MW}$	
2023 – Q3	Technology specific	PV	PV parks with a capacity of $P_{pv} \leq 1\text{MW}$	200
2023 – Q3	Technology specific	Wind	Wind parks with a capacity of $60\text{kW} < P_{WIND} \leq 6\text{MW}$	100
2023 – Q4	Common	PV and Wind	Power parks established in countries the European Economic Area with which there is an existing bilateral cross-border trade in energy	According to the methodology of Article 7 of Ministerial Decision ΥΠΕΝ/ΔΑΠΕΕΚ/123726/5096/23.12.2021 (B' 6250)
2024 – Q2	Common	PV and Wind	Wind parks with a capacity of $P_{WIND} > 6 \text{ MW}$	600 + any remaining capacity from the previous common competitive procedure
			Wind parks with a capacity of $60\text{kW} < P_{WIND} \leq 6\text{MW}$ that do not fulfill the criterion of Article 7 (3a) of Law 4414 (A' 149)	
			PV power parks with a capacity of $P_{pv} > 1\text{MW}$	
2024 – Q2	Area specific	PV and Wind	Wind parks with a capacity of $P_{WIND} > 6 \text{ MW}$	500
			Wind parks with a capacity of $60\text{kW} < P_{WIND} \leq 6\text{MW}$ that do not fulfill the criterion of Article 7 (3a) of Law 4414 (A' 149)	
			PV power parks with a capacity of $P_{pv} > 1\text{MW}$	

2024 – Q2	Common with energy storage	PV and Wind	PV and Wind parks with energy storage and without capacity limitations	200
2024 – Q4	Technology specific	PV	PV power parks with a capacity of $P_{pv} > 1\text{MW}$	200
2024 – Q4	Technology specific	Wind	Wind parks with a capacity of $60\text{kW} \leq P_{WIND} \leq 6\text{MW}$	100

Table 25: Timing, technologies and auctioned capacities of RES auctions planned for 2022 – 2024

RES auction category	Fee collected by RAAEY (€)
Common competitive procedure	2,500
Technology specific competitive procedure (PV)	500
Technology specific competitive procedure (Wind)	1,000
Common competitive procedure with RES storage	2,500

Table 26: Competitive auction participation fee

The maximum bid price for the common competitive tendering procedure (2022 Q3) for plants to be installed in Greece, as well as for the first common competitive tendering procedure (2023 Q4) for parks to be installed in the European Economic Area countries engaged in active cross-border trade, was established as follows: (a) 54 €/MWh for the PV technology, and (b) 63 €/MWh for the wind technology. For the technology specific auctions, the maximum bid price was established at: (a) 70 €/MWh for PV parks and (b) 83 €/MWh for wind parks.

In common competitive tendering procedures, a technology quota was set at thirty percent (30%). The technology quota represents the minimum percentage of the available capacity allocated to each of the RES technologies participating in the common competitive procedure, provided that the respective bid offers are submitted in compliance with the Articles 3, 7, and 8 of this Ministerial Decision ΥΠΕΝ/ΓΔΕ/66576/5877 and that the minimum competition percentage is met. The capacity allocated to each of the RES technologies may exceed the capacity determined by the above coefficient by an amount equal to ten percent (10%) of the total capacity auctioned if choosing to meet the 30% minimum percentage would result in exceeding the minimum percentage. If the excess surpasses 10%, the last project is not selected based on the 30% minimum technology factor criterion. In the context of applying the competitive procedure rules for selecting the most cost-effective projects, the allocated power for the technology may be less than the power derived from applying the 30% rate to the offered capacity.

The minimum competition level is set at eighty percent (80%) for each RES plant technology participating in a competitive process. The minimum competition percentage represents the level of participation that exceeds the originally advertised capacity. If the combined capacity of power parks participating in the competitive procedure for each technology does not meet the minimum competition percentage, the auctioned capacity is reduced to ensure compliance with the minimum competition percentage for each technology. The application of the minimum competition level leads to a reduction in the technological quota as outlined above, to ensure that the capacity ultimately auctioned fulfills the minimum competition rate for each technology. In any case, a minimum of three (3) power parks of each technology, owned by different participants, must participate in an auction for it to be valid. If the above level is not met for a technology, no capacity shall be allocated for that technology, and the competitive procedure shall be conducted without the application of the technology quota. If the above criterion is not met for any technology, the competitive procedure would be canceled. A maximum capacity limit per participant was set which could not exceed thirty-five percent (35%) of the originally tendered capacity. A last project rule was applied, where the last project of each technology, selected in order of ranking, may exceed the auctioned capacity allocated per technology by up to ten percent (10%). In particular, one plant in each technology may be selected

for the portion of its capacity that results in an excess of up to ten percent (10%) of the auctioned capacity allocated per technology.

In order for the parks to be able to participate in the competitive procedures, they must have a final connection offer by the relevant network operator, which they must have had accepted, while having submitted, if required, the letter of guarantee to the operator.

The deadline within which the awarded participants are required to establish the power parks depends on the auction and the technology. The following table presents the relevant development deadlines for the power parks that are successful in the auction.

RES auction category	Deadline
Common competitive procedure	36 months for wind power parks 30 months for PV power parks
Technology specific competitive procedure (PV)	12 months
Technology specific competitive procedure (Wind)	24 months
Common RES competitive procedure with storage	36 months for wind power parks 30 months for PV power parks
The time periods of this table are increased by twelve (12) months, if at the time of the competitive tendering procedure the selected producer is obliged by the institutional framework to carry out a competitive tendering procedure in order to implement the RES and HECHP plant.	

Table 27: Competitive auction participation fee

As regards the support scheme for energy storage projects, it was established by Ministerial Decision ΥΠΕΝ/ΔΗΕ/55948/1087/20.05.2023 (Gazette B' 3416). The scheme provides investment and annual operating aid for the construction of energy storage stations. Beneficiary projects are selected through competitive procedures and receive an investment aid of EUR 200,000 per MW, along with an operating aid calculated and adjusted for each project according to the relevant methodology determined by the RAAEY decision and provided by DAPEEP. For this purpose, the project owner must enter into an operational aid agreement with DAPEEP.

According to the Ministerial Decision, the total capacity to be tendered through the Competitive Bidding Procedures was set at 1,000 MW, representing the maximum electricity injection capacity of the power plants. The tendering process is divided into three distinct Competitive Procedures, as outlined in Table 28. The capacity ultimately awarded in each procedure may vary from the amounts listed in the table, as a "last project rule" is applied. This allows for an excess capacity award of up to 5% if the submitted financial bid does not exceed 10% of the highest selected bid without applying this rule. Any excess awarded capacity in Procedure A reduces the available capacity for Procedure B.. On the other hand, any unawarded capacity during an auction is transferred to subsequent competitive procedures.

Year – Quarter	Competitive Auction	Tendered capacity (MW)
2023 – Q2	First Competitive Auction	400
2023 – Q3	Second Competitive Auction	300
2023 – Q4	Third Competitive Auction	300
	Total	1,000

Table 28: Tendered capacity per electricity storage competitive auction (2023)

The first two Competitive Procedures distribute their auctioned capacity across the entire territory of the interconnected system, with the exception of the island of Crete. The third procedure focuses specifically on the Just Development Transition of lignite-dependent areas. Each procedure is conducted in a single-stage bidding format.

During the auction period, participants must submit bids that include their details, the Electricity Storage License, details of other necessary licenses and approvals, a technical description of the project, a financial bid, and any other information required to meet the technical and operational requirements. The financial offer should specify the annual Reference Revenue in euros per megawatt of maximum injection capacity per year (€/MW/year), which will be used to calculate the annual operating aid. If a bid proposes power and capacity lower than the current Storage License, it must include a request for the modification or division of the existing license. Such requests are considered only if the electricity storage unit is selected in the competitive procedure. The bids are evaluated based on the completeness and validity of their entries, in line with the criteria established in the Notice of Competitive Procedure. Valid bids are ranked in ascending order of cost (Reference Revenue) until the tender capacity is fully allocated, taking into account the "last project rule" which could lead to an excess of the capacity tendered up to 5%.

In cases where two or more financial offers are equal, and their combined selection exceeds the tendered capacity beyond the margin allowed by the "last project rule", projects with higher licensing maturity are selected. Licensing maturity considers factors such as the approval of environmental conditions and the issuance of a Final Connection Offer. If financial offers and licensing maturity are still tied, the Regulatory Authority for Energy, Waste and Water (RAAEY) will request the re-submission of financial bids for re-evaluation of these projects.

The results of the Competitive Procedures include a list of successful electricity storage plants, as well as a list of runners-up, up to 30% of the tendered capacity. Successful runners-up participants have the right to withdraw from the list by notifying RAAEY and requesting the return of their Participation Guarantee Letter.

A Minimum Competition Percentage of 100% is established for each procedure. If the total capacity of participating power plants falls below this percentage, the awarded capacity is reduced accordingly, and any unawarded capacity from the first competitive procedure is transferred to the second competitive procedure. A minimum of four participants, who are not affiliated or associated, are required for each procedure. If this condition is not met, the competitive procedure is postponed.

Additional limitations include a maximum participation power of 100 MW per storage power plant, a maximum participation power limit of 25% of the auctioned capacity per participant, and a cumulative capacity award limit of 250 MW across all tendering procedures. The "last project rule" allows for an excess capacity award of up to 5% if the financial offer does not exceed 10% of the highest selected offer without applying this rule. Any excess awarded capacity in the first procedure reduces the available capacity for the second procedure.

The maximum allowable bid price for Tender Procedure A is €115,000 per MW/year. Owners of supported electricity storage plants from the first and second procedures receive investment aid of €200,000 per MW. To obtain this aid, owners must submit a Letter of Guarantee of Performance and Timeliness, which must exceed the aid amount by at least 25%. Upon submission, the initial Participation Guarantee Letter is returned. Prior to the issuance of an operating license, owners must submit a Letter of Guarantee for Good Operation, of €200,000 per MW which is valid for the entire period that the storage power plant receives aid. The amount of this guarantee is reduced by €100,000 per MW after five years of operation of the plant. The Performance Guarantee is returned after the deposit of the Good Operation Guarantee, while the later shall be returned within six months after the end of the operating aid.

The aid period is set at 10 years, starting from the issuance of the operating license. An Operating Aid Contract between the plant owner and the RES and Guarantees of Origin Operator (DAPEEP) is a prerequisite for receiving aid. Upon contract-signing, the storage station is registered in the RES and CHP Register.

The Annual Aid Methodology for energy storage power plants, established by RAAEY, sets the framework for calculating operating aid, considering factors like market revenues, incentive mechanisms, and adjustments for projects not included in the aid scheme. Supported plants are grouped by their competitive procedures (A, B, and C) for revenue calculations, with adjustments possible if significant discrepancies are found. Market revenues are estimated and adjusted annually, with discrepancies settled as necessary. Monthly debit entries are managed by the RES and Guarantees of Origin Operator (DAPEEP), and any overpayments are refunded. The methodology also includes incentives to encourage efficient participation in electricity markets.

According to RAAEY Decision E-45/2023, the first auction for energy storage power plants was established. A total of 93 power plants expressed interest in participating in the auction, with a combined output capacity of 3,299.55 MW and a guaranteed energy storage capacity of 6,653.2 MWh. Decision E-130/2023 published the final list of selected power plants. Out of the 93 power plants that participated, only 12 were awarded investment aid. The total output capacity awarded was 411.79 MW, with an average weighted award price of €49,748.18/MW/year. The awarded storage capacity of these power plants was 824.14 MWh. The following table presents the list of energy storage power plants awarded in the first auction for energy storage in Greece in 2023.

	Storage license number	Company name	Output capacity (MW)	Guaranteed storage capacity (MWh)	Bid (€/MW/year)
1	AΔ-04608	HELLENiQ RENEWABLES	50	100	33,948
2	AΔ-04606	HELLENiQ RENEWABLES	25	50	39,956
3	AΔ-04411	PPC Renewables SMSA	50	100	47,291
4	AΔ-04636	PPC Renewables SMSA	48	96	48,756
5	AΔ-04855	INTRA - S. ENERGY	50	100	49,501.111
6	AΔ-04607	HELLENiQ RENEWABLES	25	50	49,885
7	AΔ-04438	AENAOS - Energy Systems	48	96	49,900
8	AΔ-04854	INTRA - S. ENERGY	25	50	55,332
9	AΔ-04945	ENERGY SERVICES DEVELOPMENT SINGLE-COMPANY	7.8	15.6	58,640
10	AΔ-05132	ENERGY COMMUNITY MEAGAPI HELIOS	8	16.54	60,000
11	AΔ-05154	ENERGY BANK I	49.99	100	60,887
12	AΔ-04892	INTRA - S. ENERGY	25	50	64,112
Total output capacity awarded (MW)					441.73
Weighted average bid price (€/MW/year)					49,748.18
Total guaranteed storage capacity awarded (MWh)					824.14

Table 29: Results of the first competitive auction for energy storage power plants

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 parks that participate in the electricity wholesale market through the Aggregator of the Last Resort, (d) a revenue from the RES levy paid by the consumers and (e) a revenue for CO2 emission rights.

The effects of the implementation of the Temporary Mechanism for the Partial Return of Income from the Day-Ahead & Intra-Day Markets on RES financing

The Temporary Mechanism, as established by Law 4951/2022 (Gazette A' 129/04.07.2022), introduces an administratively determined unit price (referred to as the "cap" or "Adjusted Producer Revenue Price") for each category of generation units and RES portfolios. Under this mechanism, every RES portfolio participating in the Day-ahead Market will be settled at the administratively determined unit price, unless the Market Clearing Price (MCP) is lower than the cap, in which case the portfolio will receive the MCP. The monetary difference between the amounts from the cap to the Day-Ahead Market (DAM) and Intraday Market (IDM) price, for each RES production power park or portfolio, is directed to the Energy Transition Fund Special Account (EL_TEM).

The primary milestones of the Temporary Mechanism can be summarized as follows:

- The implementation of this mechanism commenced on 08.07.2022 and will remain in effect until 01.06.2023, as per Ministerial Decision ΥΠΕΝ/ΔΗΕ/69734/2413/06.07.2022.
- The Adjusted Producer Revenue Price for the Renewable Energy Portfolio, also known as the Renewable Energy Portfolio Cap, has been established at 85 €/MWh, in accordance with Ministerial Decision ΥΠΕΝ/ΔΗΕ/70248/2434/06.07.2022.
- Furthermore, on 06.10.2022, the mechanism was extended and applied to Intraday Auctions (Intraday Market) based on ΥΠΕΝ/ΔΗΕ/102621/13568/06.10.2022.
- It's important to note that, as of 28 October 2022, the calculation of the Special Market Price for Renewables (SMPRES) for each RES technology has been modified. The SMPRES is now determined based on the cap of 85 €/MWh, as stipulated in Article 64 of Law 4986/2022, Gazette A' 204/28.10.2022.

The application of the temporary cap mechanism on 08.07.2022 has affected various components of the Special RES Account. These effects include: The revenues from the Day-Ahead Market (DAM) and Intraday Market (IDM) for RES projects, whether these power parks were activated before or after 01.01.2021, are now based on a fixed price of 85 €/MWh. The Differential compensation for RES projects with FiTs, which involves compensation for RES producers and credit or debit for the Special RES Account, is now settled with the SMPRES based on a rate of 85 €/MWh, rather than being based on the DAM price. The settlements related to variables that involve the SMPRES, such as the Aggregator of the Last Resort, 10-day settlement and Balancing Cost, have also been modified.

The temporary mechanism expired on 31 December 2023.

RES Levy

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 the so-called "RES Levy" ("ETMEAR") 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 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, RAAEY determines the RES Levy unit charges imposed on consumers of each category. These responsibilities were taken away from RAAEY and assumed by the Ministry for Energy for the years 2019 and 2020, while in 2021, RAAEY continued to set again those unit charges. RAAEY had requested data from DAPEEP S.A. to determine the unit charges for 2023. DAPEEP S.A. forecasted a surplus for 2024 (from 45.67 to 267.33 MEUR). To ensure financial stability and avoid burdening consumers with increased energy costs, RAAEY has adopted Decision E-235/2023

(Gazette B' 7544/2023) maintaining the unit charge at 17 €/MWh for 2024, following previous years' decisions. Keeping the base charge at 17 €/MWh helps protect the public interest and project financial viability. The charges for this levy are determined by RAAEY Decision each December for implementation in the following calendar year. This process aims to ensure no deficits by estimating the expected revenues and expenses of the national RES Special Account, while maintaining a reserve of €70 million for emergency expenses.

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 parks 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 30: New RES Levy Unit Charges (2021)

At the end of 2023, the RES financing account recorded a deficit of 92.99 Million (see Figure 24), mainly due the decreased wholesale electricity prices recorded within 2023 and possibly as a result of the implementation of the Temporary Mechanism. The main components of the RES financing account and the Subaccount for New Res & HECHP Projects are presented in Table 31 and Table 32 below.

		2022	2023
Aggregator of the last resort account	DAM and IDM revenues for units represented by the aggregator of the last resort	13.93	6.452
	Settlement of units represented by the aggregator of the last resort	-14.19	-6.418
	Aggregator of the last resort account balance	-0,26	0.034
Subaccount for the electricity market (ΛΓ1)	DAM and IDM revenues for units operating under PPAs, FiTs (activated before 1 January 2021) and the terms of the Special PV rooftop programme	1,889.42	861.64
	Imbalance settlement of units operating under PPAs, FiTs (activated before 1 January 2021) and the terms of the Special PV rooftop programme	-89.59	-95.05
	Imbalance settlement of units that are either represented by an aggregator or which participate directly in the electricity market	-83.33	(Abolished)*
	Imbalance settlement of units represented by the aggregator of the last resort	0.22	0.13
	Imbalance settlement of RES units located in Crete	2.77	0.57
	Additional settlement of Crete's electricity suppliers	14.37	15.67
	Temporary Mechanism of Optimal Forecast Accuracy (TMOFA)	2.15	(Abolished)*
	Disincentive for units represented by the aggregator of the last resort	0.67	0.47
	Imbalance cost for FiT power parks with P > 400 kW	5.12	1.89
	Total revenues	1,741.80	785.32
	Aggregator of the last resort account balance	-0.26	0.034
Subaccount for the electricity market (ΛΓ1) balance	1,741.54	785.36	
Subaccount for RES support (ΛΓ2)	RES levy (ETMEAP)	553.30	553.08
	CO ₂ emission rights	50.52	55.73
	Special fee for Production Certification Issuance	47.47	17.96
	Total revenues	651.29	626.77
	Remuneration of units operating under FiPs (activation before 1 January 2021)	408.24	-70.35
	"Readiness" Support Payments (RSP)	-1.83	(Abolished)*
	10-day settlement	-6.19	-1.68
	Total expenses	400.22	-72.03
	Non-interconnected islands' account balance	55.71	51.79
Subaccount for RES support (ΛΓ2) balance	1,107.22	606.53	
Main RES financing account	Subaccount for the electricity market (ΛΓ1) balance	1,741.54	785.36
	Subaccount for RES support (ΛΓ2) balance	1,107.22	606.53
	Total revenues	2,848.76	1,391.88
	Remuneration of units operating under PPAs & FiTs (activation before 1 January 2021)	-1,753.21	-1,621.27
	Remuneration of roof PV units	-187.01	-183.86
	Total expenses	-1,940.22	-1,805.13
	Main RES financing account balance	908.54	-413.25
Main RES financing aggregated account balance	1,218.72	-194.02	
Revenues from the "Green levy" of on diesel fuel	100.51	101,00	
Other revenues	Not applicable	0.03	
Transfer to Energy Transition Fund (Gazette B' 1101/2022 & 3476/2022)	-1,100.00	0	
RES Special Account Balance	219.22	-92,99	
<i>*Abolished due to the implementation of XBID European Cross-Border Intraday after 30 November 2022</i>			

Table 31: Structure of the Main RES' Financing Account (ΛΓ1 & ΛΓ2, in MEUR, 2021-2022, Source DAPEEP)

		2022	2023
Subaccount for New RES & HECHP Projects (ΛΓ3)	DAM and IDM revenues for units operating under FiTs (activated after 1 January 2021)	15.40	21.83
	Imbalance settlement of units operating under FiTs (activated after 1 January 2021)	10.40	15.25
	Revenues of units operated under FiPs (activated after 1 January 2021)	78.01	-33.27
	Total Revenues	103.75	3.81
	Cost of RES units remunerated under FiT (activated after 1 January 2021)	-15.43	-35.63
	Total Costs	-15.43	-35.63
	RRF	0	0
	Load Representatives' Charge for the financing of new projects	0	0
	Subaccount for New RES & HECHP Projects balance	88.31	-31.82
Subaccount for New RES & HECHP Projects aggregated balance	88.31	56.49	

Table 32: Structure of subaccount for New RES & HECHP Projects (ΛΓ3, in MEUR, 2022, Source DAPEEP)

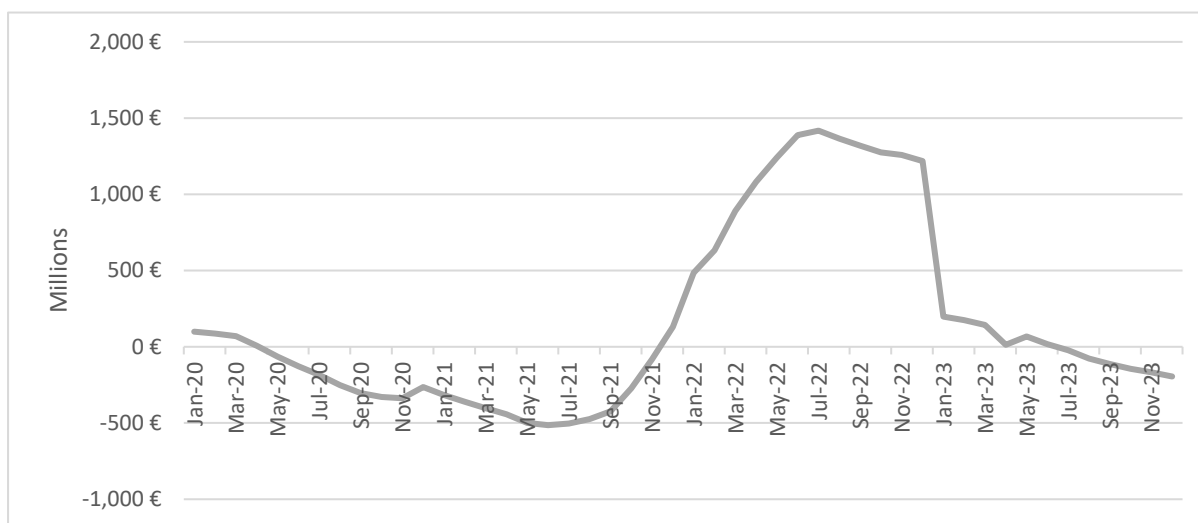


Figure 24: RES Financing Account's Progress (2020-2023, Source DAPEEP)

3.2.3.7 New RES Legislation and Regulatory Development

Primary legislation

Law 5037/2023 (Gazette A' 78/2023), marks a significant step in modernizing Greece's regulatory framework concerning energy, water, and urban waste management. This legislation not only renames the Regulatory Authority for Energy (RAE) but also expands its scope of responsibilities, transforming it into the Energy, Waste and Water (RAAEY). The law's overarching aim is to integrate the regulation of water services and urban waste management with the supervision of the energy sector, thus creating a more unified regulatory body equipped to handle contemporary challenges.

Another major aspect of Law 5037/2023 involves the transposition of European Union Directives 2018/2001 and 2019/944, which focus on the production and use of electricity from renewable sources. These directives are critical to the EU's overarching goal of reducing greenhouse gas emissions and promoting renewable energy as part of its energy mix. In this regard, the new law introduces a framework for the further development and regulation of renewable energy sources (RES) in Greece.

Specifically, the law covers provisions related to the self-consumption and self-production of electricity from RES plants, as well as high-efficiency cogeneration. It also introduces new rules for the use of RES in the transport, heating, and cooling sectors. One important measure is the mandate for a minimum percentage of electricity from renewable sources in fuel sold to the transport sector. This measure, combined with other provisions, is intended to reduce the country's carbon footprint and promote cleaner, greener energy across various sectors.

Provisions have also been introduced regarding Guarantees of Origin for electricity generated from RES, which provide a certification system for renewable energy. Furthermore, the law facilitates Greece's participation in the EU platform for the development of RES and strengthens cooperation with other EU member states for joint renewable energy projects. This cooperative framework is crucial for ensuring that Greece can meet its renewable energy targets while also contributing to the EU's collective energy goals.

A key feature of the new law is the introduction of rules for Citizens' Energy Communities (CECs). CECs are defined as civil cooperatives, where citizens, local authorities, and small businesses can collaborate to produce and manage energy, primarily from renewable sources. The law sets out the legal framework for their establishment, governance, and operations, providing a pathway for local communities to actively participate in the energy transition. The promotion of CECs is part of Greece's broader effort to decentralize energy production and empower citizens to take a more active role in achieving sustainability goals.

Law 5037/2023 also introduces significant updates related to the integration of renewable gases, such as biogas and hydrogen, into Greece's gas infrastructure. This includes provisions for assessing the effectiveness of national support schemes for renewable energy and their impact on consumers and investors. Moreover, it establishes a framework for the inclusion of renewable energy in the heating and cooling sectors, further contributing to Greece's decarbonization efforts.

The law addresses the issue of access to energy grids and infrastructure for renewable energy producers, ensuring that renewable energy projects can be integrated more smoothly into the national grid. This is crucial for expanding the use of renewables, as it reduces bureaucratic barriers and promotes the efficient use of infrastructure. Additionally, it amends rules concerning biofuels and biomass, setting sustainability criteria and greenhouse gas emission reduction targets for these energy sources.

In another key development, the law also sets forth provisions to promote electromobility, including updates to the National Plan for E-mobility. These provisions regulate the installation of charging points for electric vehicles and establish a framework for the development of related infrastructure. By doing so, the law supports Greece's transition towards greener transportation, reducing reliance on fossil fuels and cutting emissions in the transport sector.

Overall, Law 5037/2023 represents a comprehensive overhaul of Greece's regulatory landscape in relation to energy, water, and waste management. By expanding the mandate of the Energy Regulatory Authority and incorporating water services and waste management under its purview, the law aims to create a more coherent and efficient regulatory framework. Its provisions on renewable energy, electromobility, and citizens' energy communities signal a strong commitment to sustainability and the country's energy transition.

Moreover, the law's alignment with EU directives ensures that Greece is on track to meet its obligations under the European Green Deal and other international environmental agreements. By fostering collaboration between citizens, businesses, and the government, this legislation lays the groundwork for a more sustainable, resilient, and inclusive energy future for Greece.

Secondary legislation

Ministerial Decision ΥΠΕΝ/ΔΑΠΕΕΚ/7063/374 (Gazette B' 275/2023), amends the previous decision (ΥΠΕΝ/ΓΔΕ/84014/7123, Gazette 4333 B' 2022) to establish a priority framework for reviewing and granting final connection offers for RES and HECHP power parks. This competence is entrusted to the Electricity Distribution Network Operator and the Transmission System Operator. The decision is part of Greece's broader effort to promote clean energy and optimize the use of the electricity grid to achieve the maximum possible penetration of renewable energy.

A key aspect of the decision is the balanced development of wind and photovoltaic projects. It seeks to ensure that both types of renewable energy sources are equally prioritized and that projects are geographically distributed across the country. This approach aims to ensure that all regions benefit from renewable energy projects while making the most efficient use of grid resources.

The decision aligns with the objectives of the National Energy and Climate Plan (NECP) and the European REPowerEU framework, which focus on accelerating the transition to renewable energy and reducing dependence on imported natural gas. By promoting RES projects, the decision helps Greece decouple its power generation sector from fossil fuels, particularly natural gas, which is increasingly costly and volatile.

Another major goal of the decision is to support the growth of Green Power Purchase Agreements (PPAs). These bilateral agreements allow RES producers to finance their projects without relying on the operating support regime established by Law 4414/2016. Projects funded through Green PPAs, regardless of whether they include the physical delivery of energy, are given priority for grid connection. This move is intended to help mature Greece's electricity market and foster more independent RES producers.

The development of energy storage systems, such as batteries, is also prioritized in this decision. By supporting storage, the government aims to mitigate the unpredictable nature of renewable energy production and prevent large amounts of potential electricity from being wasted. Additionally, the decision emphasizes the importance

of RES projects located near Greece's borders, as these can facilitate the export of green energy to neighboring countries via electricity interconnections.

Finally, the decision promotes the development of offshore wind farms, which are seen as a promising area for expanding renewable energy capacity. It also supports projects led by Energy Communities, local initiatives that enable communities to invest in and benefit from renewable energy projects. At the same time, the framework seeks to accelerate the lignite phase out of areas traditionally dependent on lignite power, helping these regions transition to cleaner energy sources.

Ministerial Decision ΥΠΕΝ/ΔΑΠΕΕΚ/18393/686 introduces significant amendments to the framework for connecting small photovoltaic (PV) power parks to the electricity grid in Greece. One of the key changes, outlined in Article 1, concerns the addition of a new paragraph 3A to Article 13A of the Ministerial Decision ΥΠΕΝ/ΔΑΠΕΕΚ/15084/382 (Gazette Β' 759/2019). This amendment specifically addresses the connection of PV stations with a capacity of up to 10.8 kW and a maximum production capacity of 10 kW for three-phase connections and 5 kW for single-phase connections for net metering. These PV stations can also be combined with energy storage systems and benefit from a simplified connection process through an online information system managed by the Network and Non-Interconnected Islands Operator (HEDNO S.A.).

The decision also introduces paragraph 4A to Article 13A, which specifies that if a storage system using a shared inverter with the PV station is added, a separate electronic application must be submitted. The storage system must not exchange energy with the grid, meaning that the batteries should neither charge from nor discharge to the grid during the station's operation.

Further, the Decision is establishing that the grid capacity is reserved for 12 months for stations not requiring High/Medium Voltage (HV/MV) substation work and 24 months for those requiring such work. In cases involving public procurement processes, the reservation period may be extended by an additional 18 months. If the station is not connected within the specified timeframe, the grid capacity reservation is automatically revoked.

For stations installed on Non-Interconnected Islands (NII), the maximum power limits are set at 10 kW. The amendments seek to streamline the connection process for small PV stations, particularly those with energy storage, to further promote renewable energy deployment in the NIIs of Greece.

Ministerial Decision ΥΠΕΝ/ΔΑΠΕΕΚ/53607/1559 amends the previous Ministerial Decision ΥΠΕΝ/ΓΔΕ/66576/5877/2022, titled "Determination of the installed capacity per technology or category of power plants from RES and CHP, which is subject to competitive bidding, the number of competitive bidding procedures per year, the timetable for the implementation of competitive procedures, and other issues related to competitive bidding procedures." For details, refer to Chapter 3.2.3.5.

Ministerial Decision ΥΠΕΝ/ΓΔΕ/55236/3367 outlines the implementation of hybrid power stations on the island of Crete, under Measure Two of the Special Support Framework for Hybrid Stations in Non-Interconnected Islands (NIIs). This decision follows Article 21A of Law 4414/2016, which defines the support scheme for renewable energy sources (RES) and high-efficiency combined heat and power (HECHP) plants.

The decision provides the framework for the development and operation of hybrid power stations (HPS) that combine renewable energy sources like wind and solar with energy storage systems. These stations aim to reduce dependence on conventional power generation and increase the penetration of RES in Crete's energy mix. Specifically, the Ministerial Decision concerns three types of hybrid Renewable Energy Sources (RES) power plants that are set to be implemented on the island of Crete: a) Pumped Hydro Storage with Wind Farms which combine wind energy with pumped hydro storage, where excess wind power is used to pump water to a higher elevation. The stored water can then be released to generate electricity when needed. The guaranteed power capacity for such systems is up to 50 MW; b) Battery Storage with Wind Farms where wind energy is stored in batteries and can be dispatched when demand requires, ensuring better use of the generated wind power. This system also has a maximum guaranteed power of 50 MW and c) Battery Storage with Photovoltaic (Solar) Systems where the generated solar energy is stored in batteries for later use, making the system more flexible and reliable, with a guaranteed power capacity of up to 50 MW.

The legal framework is reinforced by several Greek laws and European Union directives to ensure the effective licensing and operational requirements of these projects. The decision emphasizes that no competitive bidding processes are required for the selection of projects, based on an earlier decision by the European Commission, and highlights the criteria for participation, including specific technological and safety standards.

The objective is to enhance energy security and cost-efficiency while also delivering benefits to the local community. Key provisions include the requirements for licensing, environmental permits, and timelines for the completion of these energy projects. The decision also outlines financial support measures and compliance with European state aid regulations, aiming for full integration of Crete's power system with the national interconnected grid.

Ministerial Decision ΥΠΕΝ/ΔΑΠΕΕΚ/53563/1556 establishes specific operational constraints on the injection of electricity from photovoltaic, wind, and energy storage stations, following the provisions of Law 4951/2022. It quantifies these constraints for the different technologies and applies them to stations that have either received or are in the process of receiving final connection offers from the relevant network operator. However, stations that were operational before the law's enactment or have met certain criteria are exempt from these limitations.

The decision defines the "injection restrictions" for renewable energy sources (RES) such as photovoltaic and wind power stations and energy storage systems. These constraints apply to stations that are part of the interconnected transmission system and the interconnected distribution network, with exceptions for specific stations that were already operational or met specific conditions before the law was implemented. The constraints do not apply to "Notified Stations"²¹.

For photovoltaic stations connected to the national transmission network or the distribution system, a permanent restriction is imposed on the maximum output power. The output power is calculated as a percentage of the installed capacity. For the transmission network, the maximum permissible injection is 72% of the installed capacity, while for the distribution system, it is 73%. These restrictions may be recalculated in case of changes to the installed capacity.

Wind power stations are subject to time-specific restrictions on their output throughout the day. For example, during certain hours, such as between 11:00 and 15:00, the maximum output may be reduced to 65% of the installed capacity. Similar to photovoltaic stations, any increase or decrease in installed capacity will lead to a recalculation of the maximum permissible output.

For energy storage stations connected to the national transmission system, there are time-based restrictions on the maximum injection capacity. The restrictions vary throughout the day, with specific time slots allowing for different percentages of the maximum permissible injection. Exceptions include pumped-storage stations and certain storage facilities connected in specific geographic areas such as Southern Evia, Crete, some of the Cyclades islands and certain substations.

More details on the restrictions imposed on RES and storage can be found in the tables below:

Technology	Level	Maximum output capacity compared to the installed capacity of the power plant (%)	Case of curtailment (article 10 (2) of Law 4951/2022)
Photovoltaic power plant	Transmission System	72%	a)
	Distribution Network	73%	

Table 33: PV power plant curtailments

Technology	Dispatch hours	Maximum output capacity compared to the installed capacity of the power plant (%)	Case of curtailment (article 10 (2) of Law 4951/2022)
Wind power park	09.00-11.00	80%	b)
	11.00-15.00	65%	
	15.00-17.00	80%	

Table 34: Wind power park curtailments

²¹ Wind power parks with capacity less or equal to 20 kW and other RES power plants with capacity less or equal to 50 kW.

Technology	Dispatch hours	Maximum allowed injection compared to the maximum injection capacity of the issued storage licence (%)	Case of curtailment (article 10 (13) of Law 4951/2022)
Energy storage (Article 2 (3) of Law 4001/2011)	09.00-10.00	70%	a)
	10.00-11.00	35%	
	11.00-15.00	0%	
	15.00-16.00	35%	
	16.00-17.00	70%	

Table 35: Energy storage curtailments

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 A 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 products²². 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 fueled 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 D phase of the Cyclades interconnection will complete the complex and ambitious project aimed at integrating the island cluster into Greece’s mainland power system, benefiting both the islands and the national economy. Using 353.2 km of undersea AC cables and 19.6 km of underground cables, this phase will connect Naxos to Santorini, supplying much of the islands’ energy needs and marking a critical step toward full completion by 2024.

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 (7) “medium-size” autonomous systems with a peak demand from 10 to 100 MW. Two (3) “large” autonomous systems with a peak demand of more than 100 MW (Crete, Rhodes and the system of Kos-Kalymnos). The annual demand for electricity in the NIIs

²² In February 2014, RAAEY 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 are recognized as micro isolated systems per art. 2 par. 27 of the Directive 2009/72/EC.

varies in size, from a few hundred MWh on the smaller islands (Antikythira, Agathonisi, etc.), to some TWh in the larger NII (Crete).

The share of RES' generation in the total electricity generation of the 29-autonomous power system was 8.81% in 2023. 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, Rhodes and the system of Kos-Kalymnos).

The annual electricity demand among the autonomous non-interconnected systems varies too, from few hundreds of MWh up to few TWh (Table 36). Furthermore, Table 37 presents the generation and installed capacity per RES technology for all months of 2023 in the non-interconnected islands.

	Non-interconnected autonomous power systems (islands)	Electricity Production from Conventional Plants (MWh)	Electricity Produced from RES (MWh)	% Production from RES	Demand (MWh)	Peak demand (MW)
1	St Eustratios	1,026.18	0.00	0.00%	1,026.18	0.323
2	Agathonisi	780.58	0.00	0.00%	780.58	0.22
3	Amorgos	11,673.55	449.21	3.71%	12,122.77	3.59
4	Anafi	1,495.80	0.00	0.00%	1,495.80	0.628
5	Antikythera	316.62	0.00	0.00%	316.62	0.124
6	Arkie	456.23	0.00	0.00%	456.23	0.167
7	Astepalaia	6,413.64	569.35	8.15%	6,983.00	2.53
8	Gavdos	594.86	0.00	0.00%	594.86	0.187
9	Donoussa	1,115.11	1.26	0.11%	1,116.37	0.47
10	Erikoussa	857.38	0.00	0.00%	857.38	0.426
11	Thira	260,636.23	997.63	0.38%	261,633.86	67.6
12	Ikaria	18,421.36	8,478.88	31.52%	26,900.24	7.121
13	Karpathos	35,445.04	6,227.74	14.94%	41,672.77	13.43
14	Crete*	1,591,881.94	Not available*	Not available*	Not available*	605.1*
15	Kythnos	10,989.93	372.65	3.28%	11,362.58	4.02
16	Kos-Kalymnos	351,205.52	49,847.07	12.43%	401,052.60	108.4
17	Lesbos	222,488.55	47,415.70	17.57%	269,904.26	63
18	Lemnos	47,382.67	10,667.21	18.38%	58,049.88	14.8
19	Megisti	4,833.69	0.00	0.00%	4,833.69	1.295
20	Melos	46,658.36	7,495.00	13.84%	54,153.35	14.49
21	Othonei	667.00	0.00	0.00%	667.00	0.266
22	Patmos	16,302.42	2,658.71	14.02%	18,961.13	5.54
23	Rhodes	718,368.75	123,769.29	14.70%	842,138.03	238.8
24	Samos	99,258.10	27,630.14	21.78%	126,888.23	29.6
25	Serifos	9,148.98	217.50	2.32%	9,366.48	3.68
26	Sifnos	18,182.10	2,619.81	12.59%	20,801.90	7.2
27	Skeros	14,353.14	509.27	3.43%	14,862.41	4.7
28	Semi	14,113.28	238.47	1.66%	14,351.75	3.95
29	Chios	153,149.56	32,015.47	17.29%	185,165.02	45.7
	TOTAL	3,658,216.54	322,180.38	7.57% (average)	2,388,514.99	

*Since November 2021, the island of Crete has been classified as a Small Interconnected System due to its "partial" connection with the mainland. Consequently, some data is not available. The peak demand data refers to the demand recorded on the island in 2020.

Table 36: Electricity Generation in Non-Interconnected Islands for 2023 (Source: HEDNO)

	Wind		PV		PV _{roof}		Hybrid		Total	
	Installed capacity (MW)	Production (MWh)	Installed capacity (MW)	Production (MWh)	Installed capacity (MW)	Production (MWh)	Installed capacity (MW)	Production (MWh)	Installed capacity (MW)	Production (MWh)

January	108.06	15,146.04	51.45	4,700.33	4.68	361.94	2.95	514.65	167.14	20,722.96
February	108.06	18,622.91	51.45	5,600.71	4.68	373.85	2.95	587.39	167.14	25,184.86
March	108.06	18,030.14	51.45	6,853.77	4.68	493.87	2.95	851.44	167.14	26,229.22
April	108.06	19,014.06	51.45	7,771.48	4.68	641.39	2.95	1,016.15	167.14	28,443.08
May	108.06	17,801.42	51.45	7,926.42	4.68	725.46	2.95	213.26	167.14	26,666.56
June	108.06	19,834.33	51.45	8,964.01	4.68	748.18	2.95	172.98	167.14	29,719.50
July	108.06	26,522.32	51.45	9,469.13	4.68	827.25	2.95	277.58	167.14	37,096.28
August	108.06	22,347.52	51.45	8,969.26	4.68	794.91	2.95	198.30	167.14	32,309.99
September	108.06	21,977.91	51.45	7,816.81	4.68	723.13	2.95	180.35	167.14	30,698.20
October	108.06	17,192.80	51.45	6,981.78	4.68	623.11	2.95	198.82	167.14	24,996.51
November	108.05	15,489.97	51.45	4,386.51	4.67	503.13	2.95	400.68	167.12	20,780.29
December	108.05	14,388.31	51.45	3,554.86	4.67	408.63	2.95	981.16	167.12	19,332.96
Total	108.05	226,367.73	51.45	82,995.07	4.67	7,224.85	2.95	5,592.76	167.12	322,180.41

Table 37: RES Electricity Generation and installed capacity per technology in Non-Interconnected Islands for 2023 (Source: HEDNO)

3.2.4.1 Wholesale Electricity Supply Structure in Non-Interconnected Islands

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 autonomous power systems, pursuant to Law 4001/2011 and the Code of operation of the Non - Interconnected Islands. All suppliers that are active in NII can buy the produced electricity.

The inability of existing RES plants to provide guaranteed power to the local island systems inevitably leads to continued strengthening of the conventional power resources of each island, with new thermal units designed to meet both peak demand and the necessary reserve capacity. It is noted that to ensure sufficient resources and minimize the risks to security of supply, especially in the event of power loss, in each autonomous island system, and in addition to the required power to meet the maximum demand (peak), reserve conventional capacity is also installed and kept at standby status, to cover the possibility of loss of the largest power unit in each autonomous system.

The thermal production in the Non – Interconnected Islands failed to attract the interest of new producers due to the high variable and operating costs, as well as the significant fluctuations in annual demand associated with the touristic season, which create conditions of high business risk in the repayment of the capital cost for new electricity production investments.

Consequently, the electricity production market remained regulated by compensating the sole thermal Producer at the full cost of production plus a reasonable profit, while the Suppliers operating in the NII, in order to offer uniform tariffs throughout the country, receive compensation for the additional cost of electricity that their consumers consume per NII system, through the NII Public Service Obligation (PSO).

3.2.4.2 Retail Electricity Supply Structure in NII

The Greek retail electricity market is segmented into the Interconnected System and the Non-Interconnected Islands (NII). This distinction arises from the fact that the complete liberalisation of electricity supply in the NII only occurred as of January 1, 2018, in accordance with Decision 908/2017, as published in Gazette B' 4461. As a result, the level of maturity in these two segments is not uniform. For the analysis on the retail electricity market in the interconnected network, refer to page 43.

In 2023, the retail electricity market in the NII featured the active participation of 15 Suppliers. Notably, as in the Interconnected System, PPC S.A., Mytilineos S.A., Heron S.A., Elpedison S.A., and NRG S.A serve as the Universal Service Suppliers in the NII, while PPC S.A. also extends its role as a Supplier of the Last Resort (SoLR).

	Supplier Name:
1.	PPC
2.	ELINOIL
3.	ELTA
4.	ELPEDISON
5.	ZENITH
6.	HERON
7.	KEN
8.	PROTERGIA (MYTILINEOS)
9.	NRG
10.	OTE ESTATE
11.	FYSIKO AERIO
12.	VOLTERRA
13.	VOLTON
14.	WATT & VOLT
15.	WE ENERGY
(16.)	UNIVERSAL SERVICE SUPPLIER (PPC)
(17.)	UNIVERSAL SERVICE SUPPLIER (PROTERGIA-MYTILINEOS)
(18.)	UNIVERSAL SERVICE SUPPLIER (ELPEDISON)
(19.)	UNIVERSAL SERVICE SUPPLIER (HERON)
(20.)	UNIVERSAL SERVICE SUPPLIER (NRG)
(21.)	SUPPLIER OF LAST RESORT (PPC)

Table 38: Companies active in the electricity supply market of Non-Interconnected Islands (2023)

Tables 39 and 40 found below, provide a comprehensive breakdown of the number of meters and consumption figures categorized per consumer and supplier in the country's Non-Interconnected System for 2022.

It's worth noting that Table 39 includes data related to active Suppliers as of December 31, 2023. This representation excludes the Supplier of Last Resort (SoLR), which did not serve consumers during that specific period. On the other hand, Table 40 offers a holistic view, presenting the total consumption data for the entire year, thus incorporating data from all Suppliers who were operational within the NII during the year. It's important to mention that the SoLR did not serve any consumers throughout 2023 and, as such, is not included in the data presented in Table 40.

Supplier	LV				MV		Total
	Households	Social Tariffs (Households)	Commercial / Industrial	Other	Commercial / Industrial	Other	
PPC	457,482	23,446	111,782	42,611	506	203	636,030
HERON	23,856	1,602	7,543	24	86	0	33,111
ELPEDISON	21,267	1,344	5,541	33	161	0	28,346
WATT & VOLT	0	0	0	0	0	0	0
PROTERGIA	26,817	1,520	11,304	19	145	0	39,805
KEN	0	0	0	0	0	0	0
NRG	12,927	1,383	7,165	63	80	0	21,618
FYSIKO AERIO	8,977	502	1,666	31	33	1	11,210
VOLTON	8,819	811	2,770	3	30	1	12,434
ZENITH	8,534	724	1,449	35	0	0	10,745
ELTA	2	0	101	2	3	0	105
VOLTERRA	850	26	498	40	25	6	1,445
ELINOIL	429	15	234	1	1	0	680
WE ENERGY	24	0	33	0	0	0	57
OTE ESTATE	13	0	0	0	0	0	13
PPC-USS	12,538	624	4,585	742	0	0	18,489
PROTERGIA-USS	799	40	235	51	0	0	1,125
HPQN-USS	624	24	184	29	0	0	861
ELPEDISON-USS	791	18	246	40	0	0	1,095
NRG-USS	455	25	155	26	0	0	661
Total	585,204	32,104	155,491	43,750	1,070	211	817,830

Table 39: Total number of meters per Supplier and Consumer Category (LV & MV) in the Non-interconnected Islands (31.12.23, Source: HEDNO S.A.)

<i>(In kWh)</i>		LV		MV		Total	
Supplier	Households	Social Tariffs (Households)	Commercial Industrial	Other	Commercial Industrial	Other	
PPC	1,020,338	92,242	940,210	419,395	433,966	170,654	3,076,805
ELPEDISON	70,763	6,134	95,565	175	256,576	0	429,213
HERON	83,607	7,853	148,892	250	129,616	0	370,218
PROTERGIA	38,621	2,331	134,216	348	180,844	0	356,360
WATT & VOLT	63,332	4,285	95,731	114	6,109	0	169,571
KEN	19,977	2,041	29,953	58	13,566	145	65,740
NRG	40,345	4,833	128,971	426	63,340	0	237,914
VOLTERRA	2,670	147	14,589	2,727	23,838	5,492	49,463
FYSIKO AERIO	27,988	2,251	26,196	404	51,905	2,267	111,010
ELTA	2,158	155	3,478	18	661	0	6,470
VOLTON	13,109	1,527	12,979	21	6,509	30	34,176
ZENITH	18,169	2,041	21,845	208	2,201	0	44,465
ELINOIL	1,534	75	4,551	8	585	0	6,753
WE ENERGY	59	0	756	0	0	0	815
OTE ESTATE	61	0	0	0	0	0	61
PPC-USS	19,061	3,152	17,106	1,860	0	0	41,178
PROTERGIA-USS	1,177	228	921	51	0	0	2,377
HERON-USS	910	121	517	57	0	0	1,606
ELPEDISON-USS	814	88	671	65	0	0	1,637
NRG-USS	567	119	497	73	0	00	1,256
Total	1,425,260	129,623	1,677,643	426,259	1,169,715	178,587	5,007,088

Table 40: Electricity Consumption in kWh per Supplier and Consumer Category (LV & MV) in the Non-interconnected Islands (2023, Source: HEDNO S.A.)

PPC kept its stronghold as the leading supplier in both the retail electricity market of the Non-Interconnected Islands, holding 77.77% of the total electricity meters in these areas and 61.45% of the overall consumption. It's worth noting that despite its reduced market share in terms of metering points and consumption in NII, PPC remains a significant market player.

For a comprehensive view of the market dynamics, the market shares of the Suppliers within the NII, considering both the number of supplies and consumption volume, are graphically depicted in Figures 25 and 26. This data is sourced from the HEDNO's records for 2023.

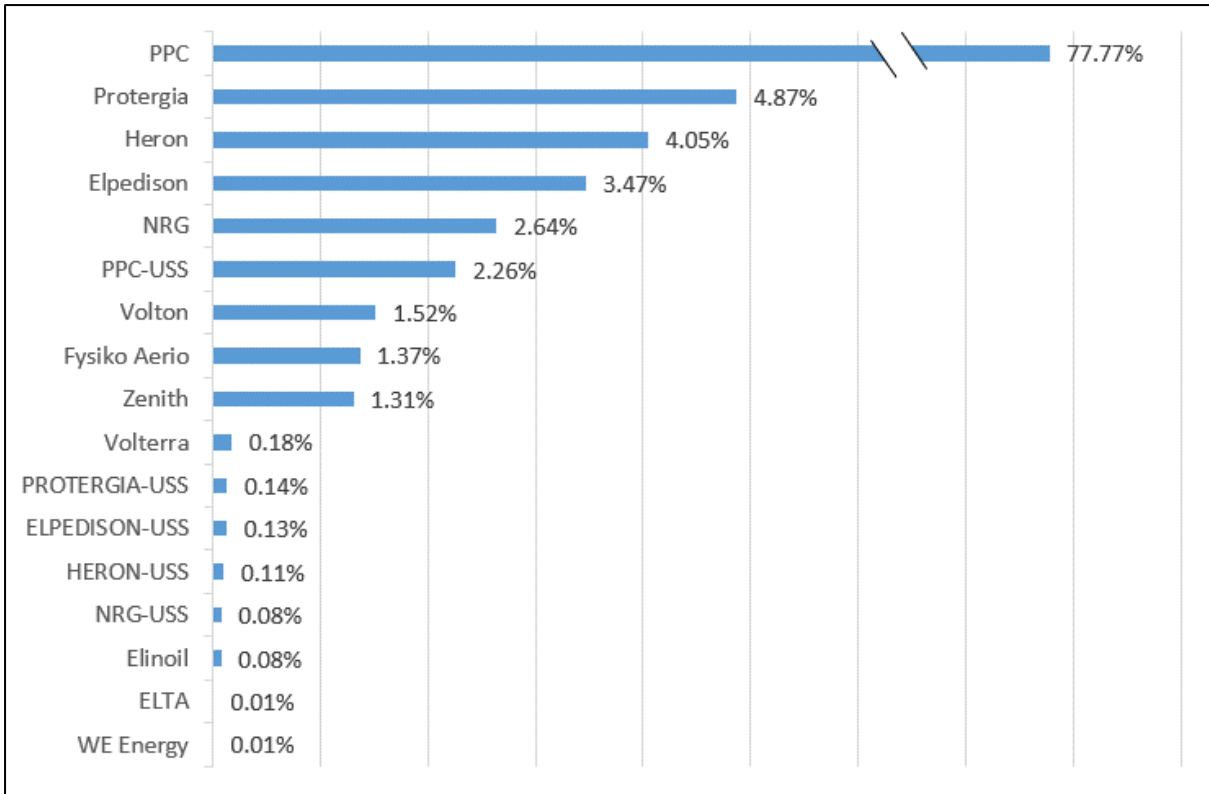


Figure 25: Market shares of suppliers based on number of meters in the retail electricity market, Non-interconnected Islands (LV & MV, 2023, Source: HEDNO S.A.)

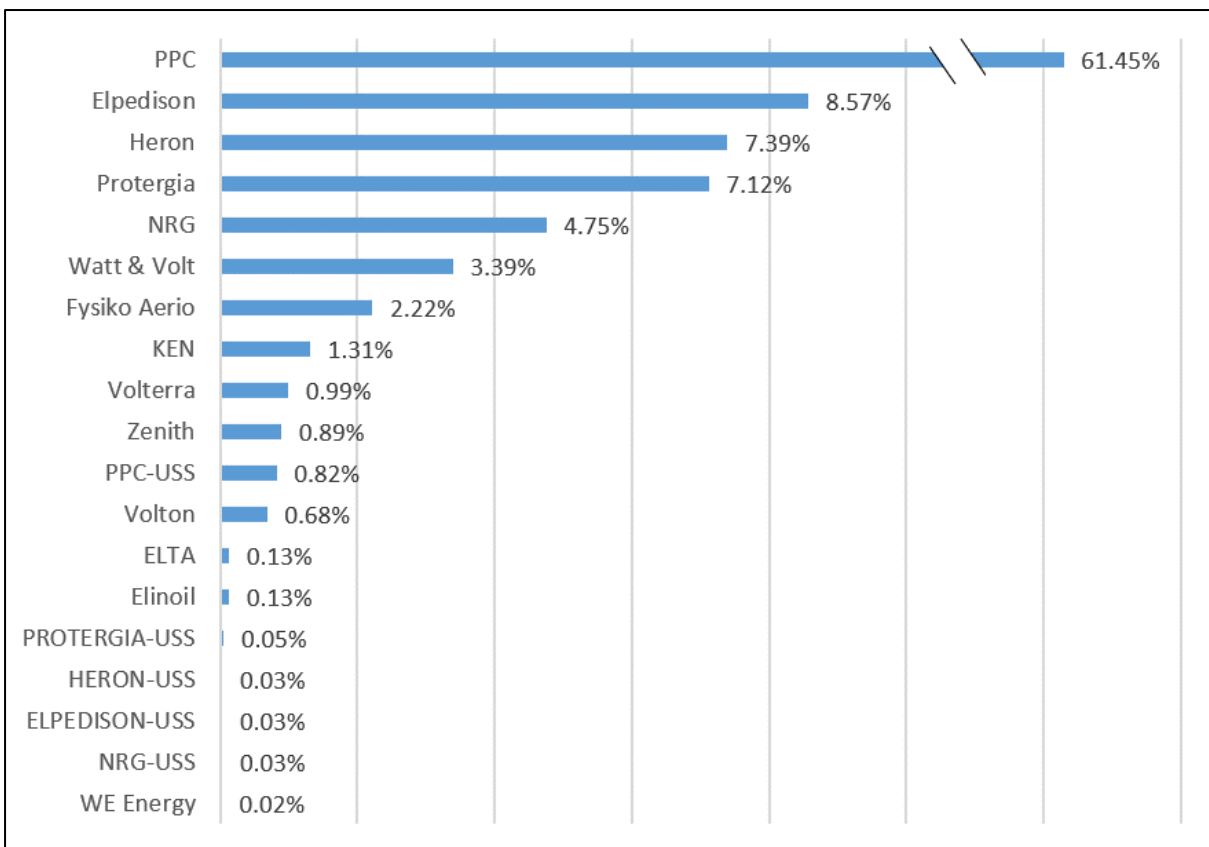


Figure 26: Market shares of suppliers based on consumption in the retail electricity market, Non-interconnected Islands (LV & MV, 2023, Source: HEDNO S.A.)

In 2023, the Herfindahl-Hirschman Index (HHI) for the Non-Interconnected Islands was 3,942 based on consumption volume and 6,118 based on metering points. Both values far exceed the threshold of 2,000, indicating a highly concentrated market, and are significantly higher than the corresponding HHI levels in the Interconnected System.

In terms of supplier switching, 9.64% of all Low and Medium Voltage consumers within the Non-Interconnected Islands switched to new suppliers in 2023. This accounts for 9.71% of the total consumption within the Low and Medium Voltage categories, as outlined in Table 41, based on HEDNO S.A. records.

Among these developments, commercial and industrial LV consumers demonstrated the highest degree of supplier switching, both in terms of the number of meters and consumption volume. They were followed by commercial and industrial MV consumers in terms of consumption, while in terms of meters, they were followed by household consumers.

For the entire electricity market, refer to Figure 16 that illustrates LV consumer switching among all suppliers in 2023, based on the number of connections.

The following table portrays data of consumer switching (LV and MV) in the NIIs in 2023 (data of HEDNO):

Consumer Category	Number of Connections in the Non-Interconnected System in 31.12.2023	Number of consumers based on connections that switched supplier in 2023	Switching rates (% in number of consumers)	Total Consumption in 2023 (MWh)	Consumption of consumers that switched supplier in 2023 (MWh)	Switching rates (% of consumption volume)
Household consumers (not including Social Tariff)	585,204	58,917	10.07%	1,425,260	100,620	7.06%
Household Consumers under Social Tariff	32,104	3	0.01%	129,623	4,016	3.10%
Small industrial and commercial consumers	155,491	19,338	12.44%	1,677,643	250,974	14.96%
Other LV consumers	43,750	470	1.07%	426,259	1,116	0.26%
Total LV consumers	816,549	78,728	9.64%	3,658,785	356,726	9.75%
Commercial and Industrial consumers	1,070	105	9.81%	1,169,715	129,102	11.04%
Other MV consumers	211	1	0.47%	178,587	175	0.10%
Total MV consumers	1,281	106	8.27%	1,348,302	129,277	9.59%
Total number of LV and MV consumers	817,830	78,834	9.64%	5,007,087	486,003	9.71%

Table 41: Number of metering points, consumption volume and switching rates per consumer category in the Non-interconnected Islands' electricity retail market in 2023.

In relation to the Universal Service provision, Figures 27 and 28 present the number of meter connections and the corresponding electricity volume consumed by the consumers under the Universal Service Supplier in the NII, categorized by consumer category, based on data provided by HEDNO. In 2023, the number of connections served under the Universal Service Supplier remained relatively stable compared to 2022, however an increase in their consumption by 8.07% was recorded.

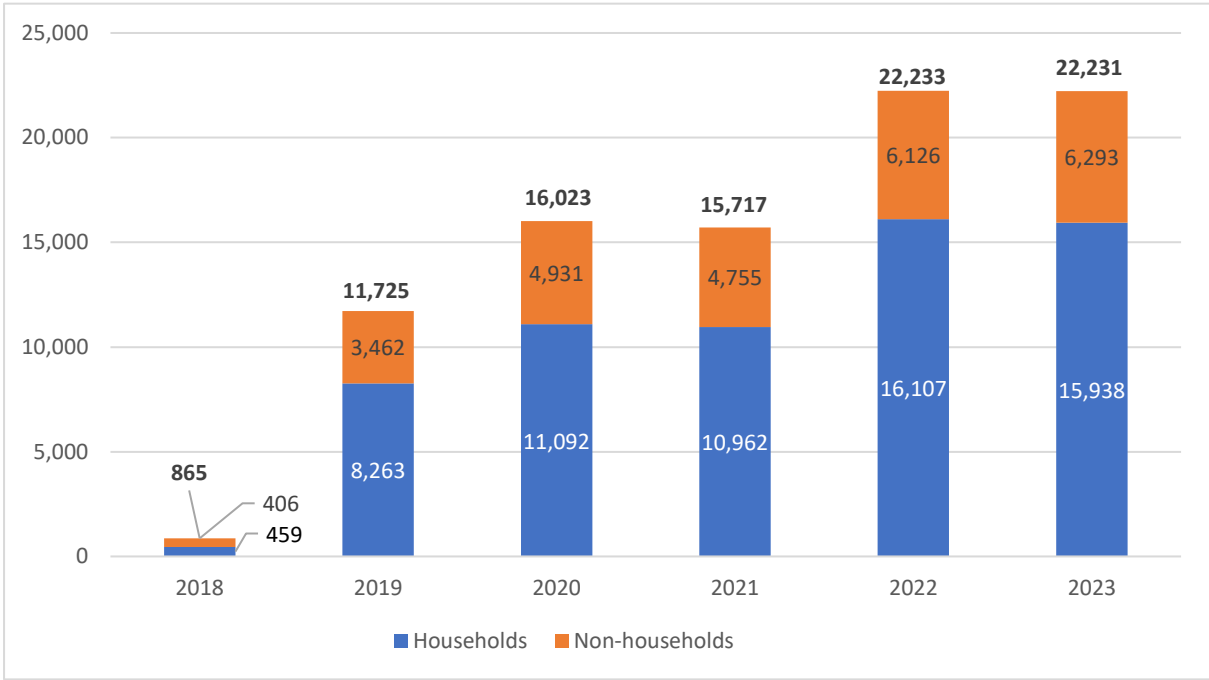


Figure 27: Electricity connections supplied under the Universal Service Supplier, Non-interconnected Islands (LV & MV, 2023, Source: HEDNO S.A.)

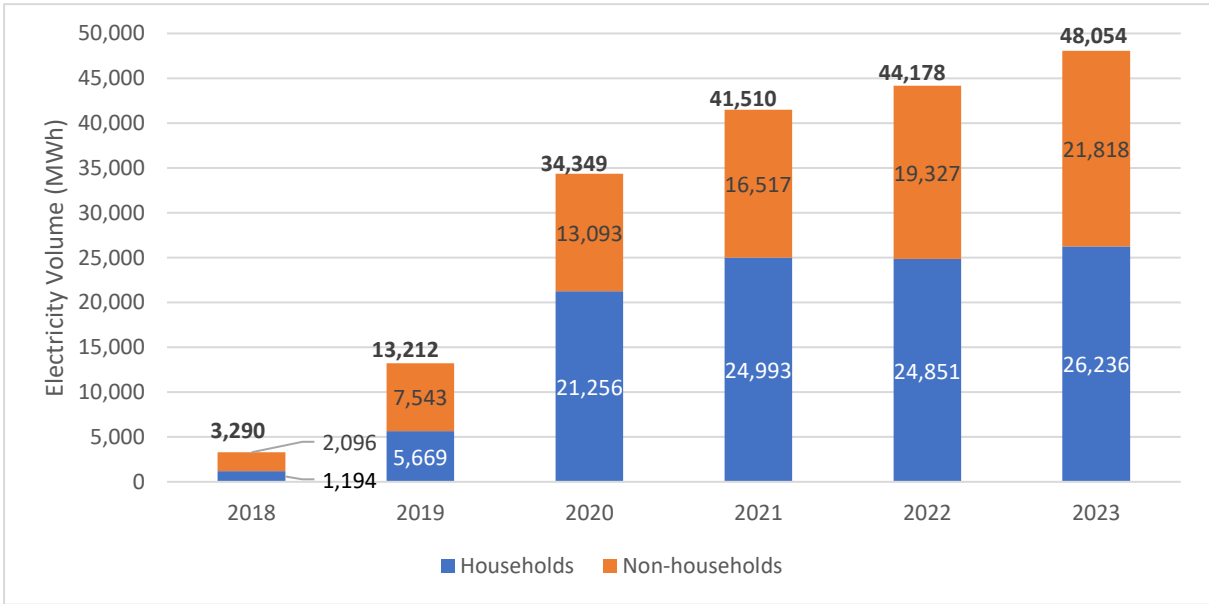


Figure 28: Electricity consumed under the Universal Service Supplier, Non-interconnected Islands (MWh, LV & MV, 2023, Source: HEDNO S.A.)

4 THE GAS MARKET

4.1 Network regulation and technical functioning

In the field of network regulation, RAAEY's main responsibility is 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 setting of the network tariffs, paid annually by the natural gas consumers to use the Transmission System and the Distribution network is based on two basic steps:

- The development of a detailed methodology (Tariff Regulation) to estimate the reasonable revenue for each year of the Regulatory Period (4-year period). The calculation of the revenue is made before the start of the Regulatory 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). Ex post, 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, in accordance with Regulation (EU) 2017/460.
- The Required Revenue and the network tariffs are approved by RAAEY based on the proposal developed by the network operators according to article 88 of Law 4001/2011.

Ownership Unbundling

At the beginning of 2019, DESFA S.A. submitted to RAAEY an administrative appeal against RAAEY's Decision 1220/2018, with which DESDA was certified under the Ownership Unbundling model. RAAEY assessed in detail the reasoning of the administrative appeal on the merits and issued Decision 460/2019 (Gazette B'3853 / 17.10.2019) with which it partially amended the conditions set out in the original certification Decision 1220/2018. Moreover, in August 2019, DESFA SA notified RAAEY of a change in its shareholding structure, as the company "Damco Energy S.A." intended to enter as a passive shareholder/investor in the company "Senflouga S.A." (which is the majority shareholder of DESFA SA) acquiring shares equal to 10% of Senflouga's issued share capital, without any voting rights. RAAEY, after examining the above request and with the consent of the European Commission, approved the acquisition of 10% of the share capital of "Senflouga S.A." by "Damco Energy S.A." As of January 2020, the Government of Greece holds a 33% stake in DESFA, while Senflouga owns the remaining 66%.

As regards distribution, since 2001, three local monopolies were 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 Attica (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 Infrastructure. Italgas Newco Srl, 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 RAAEY under the new regime as a precondition. The three DSOs were certified in May 2022 under the Ownership Unbundling model, as foreseen by the Greek Law, as was then in force,²³ imposing specific terms. However, in July 2022, the

²³ In March 2019, the Greek government had 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,²³ to avoid exchanges of confidential information, and to ensure competition at the supply market.

Greek State decided to change once again the unbundling regime, by Law 4951/2022, stepping back the requirements to legal and functional unbundling, thereby annulling RAAEY's certification decisions.

On 30 September 2023, the merger by absorption of EDA Attica and EDA Thessalonikis by DEPA was completed.

Network Development Plans

PAAEY Decision E-68/2023, approved the Ten-Year Network Development Plan (TYNDP) of the National Natural Gas System (NNGS) for 2023-2032. The Transmission System Operator of the NNGS, DESFA S.A. prepares a TYNDP according to article 68 (2) of Law 4001/2011 and the NNGS Network Code. The TYNDP is approved by RAAEY, according to the provisions of article 14 of Law 4001/2011. DESFA S.A. submitted²⁴ a TYNDP for the period 2023-2032 with a total budget of €1.32 billion, of which €476 million correspond to new projects.

Within 2023, three key decisions were published regarding network development plans for gas distribution in Greece for the period 2023-2027. In particular, Decision E-174/2023 approved the Development Plan for the Attica Distribution Network. The total approved budget for the plan is €140.95 million, with significant investments focused on reinforcing and upgrading medium and low-pressure networks, developing new connections, and replacing conventional meters with smart systems. Specifically, €8.84 million is allocated for medium-pressure network upgrades, €56.83 million for low-pressure upgrades, and €63.95 million for metering systems and supplies. The program also includes €9.33 million for the replacement of conventional meters with smart meters and €2 million for new projects. The Average Distribution Usage Charge is expected to rise to €12.00/MWh, driven by the new investments and the revised Weighted Average Cost of Capital (WACC) increased from 7.03% to 8.57%. Decision E-175/2023 approved the Development Plan for gas distribution networks across the rest of Greece. The Operator plans network development in seven regions and 39 municipalities. The forward-looking approach will first focus on network deployment, with densification following in a second phase. The plan's total budget is €402 million, allocated primarily to medium and low-pressure network development, new connections, and decompressors. Distribution network charges are expected to vary across regions, with Western Macedonia seeing the highest average rate at €18.80/MWh and Central Greece the lowest at €5.27/MWh. Decision E-176/2023 approved the Development Plan for the Thessaloniki and Thessaly Distribution Networks. It excludes the increased investment costs for connection projects and IT investments, as well as investments related to renewable gases, except for biomethane, with the total budget of €112.55 million for Thessaloniki and €95.64 million for Thessaly. The Average Usage Charge in Thessaloniki is expected to slightly decrease from €4.55/MWh to €4.47/MWh, while in Thessaly, it is expected to rise from €3.79/MWh to €4.18/MWh.

Furthermore, according to the provisions of Law 4336/2015, which 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, the company HENGAS S.A. has received a distribution license for 14 municipalities between 2020 and 2023 and was certified as an ownership unbundled DSO in 2021. The 5-year Distribution NDP²⁵ which was approved with RAAEY Decision E-105/2023 for the period 2023-2027 amounted to 50,614,755 €.

4.1.1 Network and LNG access tariffs

In 2023, RAAEY set the Required Revenue for Gas Transmission System and LNG Facility in Revithoussa for the Regulatory Period 2024-2027 (Decision E-69/2023), according to the following table:

²⁴ Unofficial English version available online at: https://www.desfa.gr/userfiles/5fd9503d-e7c5-4ed8-9993-a84700d05071/Development%20Plan%202023-2032_6.2023.pdf.

²⁵ Available in Greek only at: <https://diavgeia.gov.gr/doc/6%CE%A7%CE%A4%CE%9B%CE%99%CE%94%CE%9E-%CE%99%CE%9C%CE%93?inline=true>

Year	Basic Transmission Service ²⁶	Basic LNG service	Total Sum
2024	167,750,806	22,239,619	189,990,426
2025	164,792,475	41,342,940	206,135,415
2026	177,028,358	40,880,000	217,908,357
2027	191,938,955	39,933,822	231,872,778

Table 42: Required Revenue per basic NNGS service (€/year)

Decision E-69/2023 also lists in detail the main parameters of the WACC as they are presented in Table 43.

	2024-2027
Risk-free rate	2.36%
Market Risk Premium	5.50%
Gearing Ratio (G)	45.00%
Equity Beta	0.80%
Country Risk Premium	1.30%
Return on Equity (nominal, post-tax)	8.06%
Tax Rate	22.00%
Return on Equity (nominal, pre-tax)	10.33%
Debt Interest Rate	4.80%
Total WACC (nominal, pre-tax)	7.85%

Table 43: Main parameters of WACC- DESFA S.A. - 2024-2027 (E-69/2023)

Decision E-69/2023 also set the Allowed Revenue for the Transmission System, as split between entries and exits, and LNG Facility in Revithoussa for 2024-2027. Please note that 50% of the Allowed Revenue for the Revithoussa LNG Terminal is dispersed to the domestic exits of the Transmission System, due to the contribution of the facility to the country's security of supply. The amount of "Old Recoverable Difference" refers to the TSO's under-recovery during the years of 2011-2015 that is, by law, spread over a 20-year period and is further attributed to the domestic exits as commodity charge.

Basic Transmission Service (Entry)	Basic Transmission Service (Exit)	Socialisation of costs of LNG Activity	Basic LNG Service	Recovery of Old Recoverable Difference	Total Sum
68,476,448	68,476,448	19,123,320	22,239,619	11,674,590	189,990,425

Table 44: Allowed Revenue per basic NNGS service for the year 2024 (€)

With the same decision RAAEY approved DESFA's network tariffs for 2024, based on DESFA's proposal in accordance with the provisions of articles 5 and 18 of the Tariff Regulation (Decision 1434/2020) and the European Regulation (EU) 2017/460. In 2023, due to significant changes in the gas transmission system, particularly related to the shift in flow directions, DESFA proposed a change in the tariff methodology from the Capacity-Weighted Distance (CWD) method to the Postage Stamp methodology. Following a public consultation and discussions with ACER, RAAEY decided to adopt the Postage Stamp methodology for a two-year period, taking into account ACER's comments. In this context, RAAEY and ACER requested that DESFA begin exploring the option of applying an adjusted CWD methodology, modified to include clusters or other adjustments as described in Article 6(4) of the TAR Regulation.

Moreover, due to the aforementioned flow changes and the significant increase in exports (i.e., transit flows) from Revithoussa to cross-border exit points—particularly Sidirokastro, which supplies Bulgaria—it has become clear that the dispersion charge of the Basic LNG Facility Service should apply to all exit points of the system,

²⁶ 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.

rather than only the domestic ones, as had been the case until now. In contrast, the Energy Charge related to the "Old Recoverable Difference" continues to be applied solely to internal (domestic) exit points.

Transmission System for each Entry and Exit	SDM _i (€/kWh GCV /Hour/Year)	SEM (€/kWh GCV)	SDDY (€/kWh GCV /Hour/Year)
Entry Sidirokastro	2.9175706	-	-
Entry Ag. Triada	2.9175706	-	-
Exit Sidirokastro*	4.3000262	0.0001831	1.1441782
Exit North Zone	4.3000262	0.0001831	1.1441782
Exit South Zone	4.3000262	0.0001831	1.1441782
LNG Tariffs	SDY (€/kWh GCV /Hour/Year)	-	-
LNG Facility	1.9239538	-	-
<i>*The use of an Exit Point as an Entry Point that is also an Interconnection Point and vice versa, is charged with the tariffs of the respective Entry Point, based on article 9 (6) of the tariff regulation.</i>			

Table 45: Natural Gas Transmission and LNG Tariffs for 2024

B. Distribution System access tariffs

RAAEY Decision 485/2022 approved the second revision of the Tariff Regulation. This revision outlines the methodology for calculating the Required Revenue and the tariffs for the Basic Activity of Natural Gas Distribution. Key factors in determining the Required Revenue include the value of the Distribution Regulated Asset Base (RAB) and the rate of return, which reflects the Weighted Average Cost of Capital (WACC) for the Distribution Activity. The WACC is determined annually throughout the Distribution Regulatory Period. Specifically, Article 6 of the Methodology provides a detailed explanation of how to calculate the values of the individual parameters of the WACC in nominal terms. The revision was not extensive and focused only on implementing Article 108 of law 4812/2021 regarding the possibility of redistributing the recoverable difference accumulated in one network to other networks owned by the same company or having the same mother company.

In 2023, no new RAAEY Decisions were issued concerning the Required Revenue and distribution tariffs. This is due to the change of ownership and the restructuring of DEPA Infrastructure (see section 4.1), during which the DSOs did not submit in time Development Plans or tariff proposals. As a result, the previous RAAEY Decisions, specifically Decisions 1428/2020, 1429/2020, 1430/2020 and Decision 421/2021, pertaining to Required Revenue and distribution tariffs for Gas DSOs EDA ATTIKIS, EDA THESS, DEDA and HENGAS, respectively, for the Regulatory Period 2019-2022, remain in effect for 2024, adjusted with the consumers' price index, according to Article 16 of the Tariff Regulation.

	2019	2020	2021	2022
EDA ATTIKIS				
Return on RAB	22,012,344	21,465,064	21,377,544	22,405,195
Depreciation	15,062,659	15,544,034	15,630,624	15,692,478
OPEX	18,876,289	22,480,076	24,795,117	25,127,239
Other Revenues	697,228	471,550	195,000	200,850
Old Recoverable Difference	4,048,890	4,056,988	4,065,102	4,073,232
Total	59,302,955	63,074,612	65,673,387	67,097,295
EDA THESS – THESSALONIKI				
Return on RAB	15,355,185	15,043,076	14,802,418	14,650,812
Depreciation	8,832,137	9,223,480	10,291,278	10,832,711
OPEX	9,962,846	11,235,846	12,314,312	12,833,926
Other Revenues	436,005	666,066	657,436	690,983
Old Recoverable Difference	-607,659	-608,874	-610,092	-611,312
Total	33,106,504	34,227,462	36,122,480	37,015,154
EDA THESS – THESSALIA				
Return on RAB	7,041,442	7,184,932	7,227,278	7,211,101
Depreciation	4,148,949	4,467,287	5,073,365	5,377,563
OPEX	6,604,361	7,472,225	8,697,673	8,254,239
Other Revenues	396,552	515,103	562,703	574,380
Old Recoverable Difference	-1,205,075	-1,207,485	-1,209,900	-1,212,320
Total	16,193,125	17,401,857	19,225,713	19,056,204
DEDA – Central Greece				
Return on RAB	2,903,532	2,640,835	3,442,295	3,983,493
Depreciation	1,000,284	1,175,423	1,684,587	2,009,280
OPEX	2,687,321	3,843,617	4,746,442	4,713,229
Other Revenues	0	0	0	0
Old Recoverable Difference	465,166	466,096	467,028	467,962
Total	7,056,302	8,125,970	10,340,352	11,173,964
DEDA – Central Macedonia				
Return on RAB	1,535,872	1,417,680	2,045,862	2,324,340
Depreciation	570,310	667,981	1,032,822	1,200,998
OPEX	1,377,465	2,909,717	4,244,014	4,221,454
Other Revenues	0	0	0	0
Old Recoverable Difference	273,584	274,131	274,680	275,229
Total	3,757,231	5,269,510	7,597,377	8,022,022
DEDA – Eastern Macedonia				
Return on RAB	1,796,234	1,652,491	2,541,660	3,163,465
Depreciation	665,229	785,765	1,281,503	1,609,570
OPEX	1,636,331	3,046,816	4,616,752	4,891,352
Other Revenues	0	0	0	0
Old Recoverable Difference	294,018	294,606	295,195	295,785
Total	4,391,812	5,779,678	8,735,111	9,960,173
DEDA – Peloponnese Distribution Network				
Return on RAB	105,282	94,053	85,675	83,080
Depreciation	39,801	44,639	45,015	45,887

OPEX	97,534	74,186	57,135	45,206
Other Revenues	0	0	0	0
Old Recoverable Difference	12,397	12,422	12,447	12,472
Total	255,013	225,300	200,272	186,645
DEDA -Western Greece				
Return on RAB	0	0	152,694	751,410
Depreciation	0	0	50,374	404,212
OPEX	0	0	1,650,459	2,549,222
Other Revenues	0	0	0	0
Old Recoverable Difference	0	0	0	0
Total	0	0	1,853,527	3,704,844
DEDA -Western Macedonia				
Return on RAB	0	0	80,771	890,133
Depreciation	0	0	26,194	382,033
OPEX	0	0	1,427,568	2,942,799
Other Revenues	0	0	0	0
Old Recoverable Difference	0	0	0	0
Total	0	0	1,534,533	4,214,964
DEDA-Epirus				
Return on RAB	0	0	0	247,424
Depreciation	0	0	0	67,205
OPEX	0	0	0	1,170,517
Other Revenues	0	0	0	0
Old Recoverable Difference	0	0	0	0
Total	0	0	0	1,485,146

Table 46: Required revenue – EDA / DEDA

In July 2021, RAAEY set the Required Revenue and the distribution tariffs for the DSO Hellenic Natural Gas Distribution (HENGAS S.A) for the Regulatory Period 2021-2024, in accordance with the Tariff Regulation (Decision 421/2021). The nominal pre-tax weighted average cost of capital was set at 7.03% for each year of the Regulatory Period 2021-2024.

	2021	2022	2023	2024
Hellenic Natural Gas Distribution Network				
Return on RAB	950,821	1,780,390	2,130,690	2,659,437
Depreciation	569,465	984,537	1,090,937	1,200,597
OPEX	2,092,141	3,235,109	3,578,139	3,829,618
Other Revenues	0	0	0	0
Total	3,612,426	6,000,037	6,799,767	7,689,652

Table 47: Required revenue – HENGAS S.A

In 2023, the distribution tariffs were adjusted based on the annual Consumer Price Index of 2023, based on Article 16 of Tariff Regulation. Therefore, the regulated distribution tariffs of 2024 are the following:

	Attica	Thessaloniki	Thessaly
Capacity charges €/kWh/h			
Households	1.2089543	0.4276857	0.4933089
Commercial	1.2089543	0.4276857	0.4933089
Industrial	4.8628507	1.7111787	1.9726651
A/C, Cogeneration	1.2082905	N/A	N/A
CNG	N/A	0	0
Other	N/A	N/A	N/A
Energy charges €/kWh			
Households	0.0162292	0.0118407	0.0120689
Commercial	0.0162292	0.0118407	0.0120689
Industrial	0.0005539	0.0001819	0.0001755
A/C, Cogeneration	0.0029916	N/A	N/A
CNG	N/A	0.0010684	0.0008483
Other	N/A	N/A	N/A

Table 48: Capacity and energy tariffs for EDAs 2024

HENGAS							
	Primary network	Remote Network of Velventos	Remote Network of Voio	Remote Network of Servia	Remote Network of Kalamata	Remote Network of Nea Propodida	Remote network of Sparta
Capacity charges €/MWh/h							
Households/ Commercial	1,579.5958	1,643.6962	1,593.8828	1,647.3024	1,622.2304	1,642.3265	1,591.9554
Industrial	4,814.9671	4,963.7777	4,823.5645	4,897.0405	4,957.1799	4,854.3753	4,858.2554
Energy charges €/MWh							
Households/ Commercial	20.8790	23.3801	21.1449	22.5551	22.7970	22.4304	20.8642
Industrial	0.8999	0.8775	0.8908	0.8932	0.9392	0.8815	0.8598

Table 49: Capacity and energy tariffs for HENGAS 2024

DEDA			
	Capacity charges €/MWh/h	Energy charges €/MWh	Penetration Surcharge (€/MWh)
Eastern Macedonia			
Households	1,196.8137	20.3594	0.9226
Commercial	1,202.8876	11.4071	0.9226
Industrial	7,584.9184	0.7034	0.0738
Western Greece			
Households	925.8748	17.1124	0.9226
Commercial	863.1966	11.3198	0.9226
Industrial	5,566.4403	0.7831	0.0738
Western Macedonia			
Households	1,009.1045	13.9792	0.9226
Commercial	920.1247	17.8704	0.9226
Industrial	4,555.0732	1.0899	0.0738
Epirus			
Households	1,104.6658	15.5717	0.9226
Commercial	1,119.3131	14.3825	0.9226
Industrial	4,764.5954	0.8973	0.0738
Central Macedonia			
Households	1,179.3667	18.1842	0.9226
Commercial	1,172.5776	12.9582	0.9226
Industrial	6,467.4142	0.5456	0.0738
Peloponnese			
Households	716.8535	14.4767	0.9226
Commercial	690.6291	16.4576	0.9226
Industrial	6,503.8938	0.6386	0.0738
Central Greece			

Households	1,287.7901	16.0793	0.9226
Commercial	1,302.8075	13.7638	0.9226
Industrial	7,117.5776	0.5875	0.0738

Table 50: Capacity and energy tariffs for DEDA 2024

The "penetration surcharge" refers to a regulated distribution surcharge imposed on gas consumers, designed to address revenue shortfalls in certain Natural Gas Distribution Networks. As outlined in Article 88 of Law 4001/2001, when there is an under-recovery of the Required Revenue in a Natural Gas Distribution Network that includes Emerging Natural Gas Distribution Areas, this shortfall (Recoverable Difference) may be recovered, in part or in full, through the tariffs of the next Regulatory Period. The surcharge applies across Gas Distribution Networks whose Licences are owned by the same legal entity or by entities that are controlled by or under common control with the legal entity holding the licence of the network generating the under-recovery. The procedure prioritizes the set-off of under-recovery against over-recovery in other networks managed by the same legal entity or by affiliated entities. This "penetration surcharge" is calculated per consumer category and is uniform per unit of energy and per unit of capacity for all affected networks, ensuring equitable distribution of costs. The "penetration surcharge" is approved by RAAEY after the request of the distribution system operator responsible for managing the relevant networks.

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 participate 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.

Under the current framework DESFA S.A., procures short-term standardized products (STSPs) to perform network balancing in the trading platform that began its operation in March 2022 and according to the legal framework, can also procure balancing services for those situations in which STSPs will not or are not likely to provide the response necessary to keep the transmission network within its operational limits or in the absence of liquidity of trade in STSPs.

For this reason, the transmission system operator submits to RAAEY for approval the planning for balancing gas needs for the next year. By Decision E-64/2023, RAAEY approved the balancing plan submitted by DESFA for the year 2024, according to which 93% of the balancing needs are expected to be covered by procuring STSPs in the trading platform and 7% by balancing services following a market-based procedure, framework contract with multiple suppliers through an international tender procedure. The balancing gas needs for 2024 amount to 0.92% of the total estimated gas demand (861 GWh) for purchasing gas and 1.29% (1.2 TWh) for selling gas.

RAAEY is also responsible for approving the parameters involved in the calculation of the balancing services cost and the methodology for allocating these costs to the Transmission System users. By Decision 229/2023 (Gazette B' 2333/2023), RAAEY approved the balancing cost allocation scheme and the relevant shippers' charges, for 2023. 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

NNGS capacity auctions

RAAEY issued decision E-35/2023 regarding the capacity allocation through actions for the interconnection points of the NNGS for the gas year 2023-2024. In particular, the Authority decided that at:

A. Interconnection Point "Kipi":

1. **Monthly Conditional Transport Capacity Product:** Allocation of 46,000,000 kWh/day for each month of the 2023/2024 gas year, or until the month prior to the start of operations at the new Entry Point "Amphitrite," whichever occurs first. The starting price for this monthly capacity product will be determined by applying a short-term usage coefficient B, equal to that of the quarterly product.
2. **Daily and Intraday Conditional Transport Capacity Products:** These will be available each day of the 2023/2024 gas year or until the day preceding the start of operations at "Amphitrite." For days in months without a monthly product allocation, the starting price of the daily product will also apply the short-term usage coefficient B for the quarterly product.
3. **Capacity Usage Condition:** The quantity of natural gas physically entering from northern NNGTS entry points should remain below 171,172,292 kWh/day, with a minimum discount of 10%.
4. **No Allocation of Firm Transport Capacity for Delivery** throughout the 2023/2024 gas year.

5. **No Allocation of Interruptible Transport Capacity** for either delivery or receipt throughout the 2023/2024 gas year.

B. Interconnection Point "Nea Mesimvria":

1. **Discontinuation of Conditional Transport Capacity Delivery** starting in the 2023/2024 gas year.
2. **Non-Bundled Firm Transport Capacity for Delivery** is to be offered for a 15-year term, deviating from Regulation (EU) 2017/459 Article 19 provisions.
3. **Non-Bundled Interruptible Transport Capacity for Delivery** for the 2023/2024 gas year.
4. **Non-Bundled Interruptible Transport Capacity for Receipt** for the 2023/2024 gas year.

C. Entry Point "Amphitrite":

1. **Annual Conditional Transport Capacity Product:** Allocation of 46,000,000 kWh/day, with long-term usage tariff as approved by the Authority, effective from the commercial operation start of "Amphitrite."
2. **Quarterly/Monthly Conditional Transport Capacity Products:** The capacity available will depend on prior auction results, with charges applicable from the product duration start or the commencement of "Amphitrite's" operations, whichever is later.
3. **Daily/Intraday Conditional Transport Capacity Products:** To be offered with available capacity determined by results from prior auctions for longer-duration standardized products, starting from the commercial operation of "Amphitrite."
4. **Capacity Usage Condition:** Maintains natural gas import levels from northern NNGTS entry points below 171,172,292 kWh/day, with a 10% minimum discount.
5. **Capacity Product Auctions on PRISMA Platform.**
6. **No Allocation of Firm Transport Capacity for Delivery** throughout the 2023/2024 gas year.
7. **No Allocation of Interruptible Transport Capacity** for both delivery and receipt throughout the 2023/2024 gas year.

D. Exit Point "Komotini - DESFA/IGB":

1. **No Allocation of Interruptible Transport Capacity for Delivery** in upcoming annual product auctions, with an assessment of the quantity and interruption probability post-commercial operation. Allocation will occur via short-term standardized product auctions.

E. Coupled Points "Amphitrite" and "Komotini - DESFA/IGB":

1. **Annual Transport Capacity Product** of up to 107,470,800 kWh/day. The final capacity will be set according to joint methodology calculations by DESFA and ICGB, following Regulation 2017/459 Article 6. Products will have long-term usage tariffs effective from "Amphitrite's" operational start.
2. **Quarterly/Monthly Transport Capacity Products:** Allocation based on prior auction results, with usage charges starting either on product duration start or "Amphitrite's" operation commencement.
3. **Daily/Intraday Transport Capacity Products** will reflect available capacity as determined by results of prior longer-duration product auctions, effective from "Amphitrite's" operational start.

F. Price Steps for Increasing Bid Auctions: Major and minor price steps are set at 20% and 4% of the starting price, respectively, in EUR/kWh/day/period.

The Operator must re-evaluate its proposal and make a new recommendation for capacity allocation if flow conditions at NNGTS points change significantly.

4.1.4 Gas Infrastructures

Trans Adriatic Pipeline (TAP)

TAP AG has been granted an exemption for 25 years from Article 9 of the Directive on ownership unbundling, from Article 32 on third party access for the initial transport capacity of 10bcm/y and from Article 41(6), (8) and (10) of the Directive on tariffs.

In 2020, the Trans Adriatic Pipeline network code (TNC) was approved by the Regulatory Authorities of Greece (RAAEY 1036/2020), Italy (ARERA) and Albania (ERE) following the provisions of the Exemption decision taken in 2013, adopting the Final Joint Opinion (FJO) (RAAEY 269/2013), as amended in 2015.

Drawing from nearly a year of hands-on experience in pipeline management and operation (December 2020-October 2021), TAP AG has undertaken a proactive initiative to refine the Network Code based on the feedback received by market participants. The primary changes proposed in the TNC include the following: (a) The streamlining of the registration process within the TAP pipeline transmission system. (b) Enhancement of the guarantee deposit procedure by proposing the establishment of an account, allowing registered members to deposit financial guarantees, capped at €500,000. Additionally, for transaction security, the TAP Operator can nullify a member's credit limit in case of outstanding debts. A maximum credit limit of €50 million was introduced, aligning with the maximum uninterrupted capacity offered for one gas year. (c) The definition of a new virtual entry point in TAP aimed at making interruptible day ahead exit capacity from the gas transmission system operated by DESFA (at Nea Mesimvria) usable by the market. The new product will allow the transportation of gas from Nea Mesimvria to other exit points in forward flow direction (Albania and Italy).

In a collaborative effort, the Regulatory Authorities of Greece, Italy, and Albania meticulously reviewed the submitted proposal, considered the feedback received by three participants in the public consultation, suggested amendments and granted approval to the final text of the TNC submitted by TAP AG ([Decision 265/2022](#)).

In terms of expansion, the pipeline has been designed with the flexibility to expand up to 20 bcm/y and it is also foreseen that the total capacity can be further expanded with additional investments. In the Exemption Decision, the Regulatory Authorities imposed on TAP AG, the obligation to increase the pipeline capacity to 20 bcm/y through market mechanisms, and in line with the best practices of the European Union.

In July 2021 a new market test was launched where non-binding offers were submitted for the interconnection point of the TAP pipeline with the NNGS in Nea Mesimvria for capacity of 15,000 MWh per day for the period 2021-2023 from NNGS to the TAP pipeline, and also capacity in the same direction equal to 30,000 MWh per day for the period 2023-2031. DESFA, despite the lack of interest during the submission of non-binding offers, included offer levels in the direction from the TAP pipeline to NNGS, as to facilitate any potential future interest for entry capacity at Nea Mesimvria.

After the first phase of the market test, the three involved Operators, TAP, SRG and DESFA, prepared a Market Demand Assessment Report²⁷, which was published in October 2021 and highlighted the need to initiate an incremental capacity project. The Operators submitted to the Authorities their proposal for the Increased Capacity Project after conducting a public consultation. The proposal was based on the provisions of paragraph 3 of Article 27 and paragraph 1 of Article 28 of the CAM Regulation. The results of the Project Proposal showed that no new investments are required for offering exit capacity from NNGS to TAP at Nea Mesimvria, beyond those already included in the current approved NNGS NDP, namely the new compression plant at Abelia and the booster compressor at Nea Mesimvria.

The necessary investments to make available entry capacity from TAP to the NNGS are distributed in two offer levels. Offer Level 1 includes new 38 km of 30 inch pipeline from Abelia to Lamia, in parallel to the existing NNGS pipeline and a new 12 MW compressor park at Platamonas with a total cost estimated at €108 million. Offer

²⁷ Available online at: https://www.entsog.eu/sites/default/files/2021-11/2021_DAR_GR-TAP-IT.pdf.

Level 2 which includes new 92 km of 30-inch pipeline from Larissa to Spercheios, parallel to the existing NNGS pipeline and new 18 MW capacity park at Litochoro at a total cost of €189 million. According to preliminary technical studies constructions will be completed in the first quarter of 2027 for offer level 1 and in the third quarter of 2027 for offer level 2.

With [Decision 818/2022](#) RAAEY in cooperation with the other Regulatory Authorities, approved the project proposal of the TAP, SNAM and DESFA and defined f-factor, in accordance with Article 23 of the CAM Regulation, at 0.75. RAAEY evaluated that the above-mentioned projects are expected to work positively for the Greek system because there will be more flexibility in terms of pressure management and increase in pipeline reserves, improvement of N-1 Rule in terms of security of supply, diversification of supply sources using commercial reverse flow from Italy and contribution to the climate neutrality objective.

It should be noted that the three Operators have indicated their intention to proceed to a second binding phase at a later stage. In this regard, TAP, SRG and DESFA have launched the 2023 Market Test in July 2023, in line with the CAM NC timeline. As of January 2024 the Market Test is still ongoing and the TSOs plan to open a Revision Window for the Non-Binding Phase of the 2023 Market Test between 19th January and 2nd February 2024 to allow all interested parties to either submit new Non-Binding Demand Indications and/or to revise the ones already submitted between July-August 2023 during the Demand Assessment Phase of the 2023 Market Test.

Furthermore, within 2023, RAAEY approved with Decision 144/2023 the change in the stake of Trans Adriatic Pipeline AG. Specifically, the proposed change was from the initial composition of AzTAP GmbH (20%), BP Pipelines TAP Limited (20%), SNAM S.p.A. (20%), Fluxys Europe BVBA/SPRL (19%), Enagás International S.L.U. (16%), and Axpo Solutions A.G. (5%) to the following: AzTAP GmbH (20%), BP Pipelines TAP Limited (20%), SNAM International B.V. (20%), Fluxys Europe BVBA/SPRL (19%), Enagás International S.L.U. (16%), and Axpo Solutions A.G. (5%). Following this approval, TAP AG later requested further changes to its shareholding structure under Article 18 of the Gas Licensing Regulation. This new request proposed an adjustment to the stake held by Fluxys and Enagás, increasing their shares to 20% each, effectively modifying the structure to: AzTAP GmbH (20%), BP Pipelines TAP Limited (20%), SNAM International B.V. (20%), Fluxys Europe BVBA/SPRL (20%), and Enagás International S.L.U. (20%). The RAAEY, in exercising its regulatory duties and powers under the Gas Licensing Regulation, carefully reviewed the relevant documentation to assess both the formal completeness of the application and its impact on the technical and organizational capabilities of the applicant. The review concluded that TAP AG's the proposed shareholding changes did not affect the criteria for the continuation of the company's LNG and LNG Licences. TAP AG retained its technical competence, administrative capacity, and operational integrity, ensuring the continued sound and safe operation of the pipeline project. Under Article 63 of Law No. 4001/2011, the RAAEY Decision E-53/2023 approved these shareholding increases. It was determined that the increase in the shareholding did not necessitate a re-initiation of the certification procedure, as both Fluxys Belgium SA and Enagás Transporte SAU were already certified under the ownership unbundling model by the competent regulatory authorities.

Natural Gas Pipeline Greece - Italy (IGI Poseidon)

The Poseidon Pipeline is a significant energy infrastructure project that forms part of the broader EU strategy to enhance energy security and market integration. It consists of a 210 km offshore section that stretches from the Ionian coast in Greece to the vicinity of Otranto in Italy, playing a critical role in transporting natural gas from the Eastern Mediterranean to Europe. The pipeline begins at the Florovouni compressor station in Thesprotia, Greece, where it connects to other major projects like the EastMed pipeline. From there, it crosses the Ionian basin, reaching the Italian coast east of Otranto, before linking to Italy's national gas transmission system via a metering station.

The project has an initial capacity of 12 billion cubic meters per annum (bcm/a), with the potential to be upgraded to 20 bcm/a. It consists of several key components: the compression station in Greece, an onshore pipeline segment from the station to the Greek landfall, the offshore pipeline across the Ionian Sea, and an onshore pipeline connecting the Italian landfall to the metering station.

In addition to its standalone importance, the Poseidon Pipeline is integrated with the EastMed project, enabling the transport of natural gas from the Eastern Mediterranean to Italy and beyond. It is recognized as a Project of Common Interest since 2013 according to Regulation (EU) 347/2013 by the European Union and is critical to the

Southern Gas Corridor, enhancing energy supply security, fostering competition, and exerting downward pressure on gas prices in the region. The pipeline is fully licensed and poised for development, aligning its schedule with the EastMed pipeline. In line with Article 25, IGI Poseidon submitted an Investment Request to the energy regulatory authorities of Greece (RAAEY), Cyprus (CERA), and Italy (ARERA). After consulting with ACER, these regulatory bodies jointly assessed and approved the request,²⁸ allowing the project to proceed.

Overall, RAAEY's role emphasizes cross-border collaboration, harmonization of rules, and strategic projects like EastMed, which are crucial for advancing the European energy market and ensuring security and competitiveness in energy supply.

Gas Interconnector Greece–Bulgaria (IGB)

ICGB AD has been granted a 25-year exemption under Article 36 of Directive 2009/73/EC from ownership unbundling, partial third-party access and tariff approval for the Interconnector Greece-Bulgaria (IGB) pipeline. The IGB pipeline started commercial operation on October 1st 2022, following an amendment of the Exemption Decision by the Regulatory Authorities of Greece (RAAEY) and Bulgaria (EWRC) (RAAEY [Decision 742/2022](#)²⁹) for the extension of the Commercial Operation Date from July to October 1st.

Certification Decision

Before its commercial operation, IGB was certified under the Independent Transmission Operator (ITO) model, as was foreseen in the Exemption Decision. RAAEY, through its Decision 482/2022, approved a joint document between the Greek and Bulgarian Regulatory Authorities for the Preliminary Certification of IGB. This document evaluates the extent to which the company aligns with the regulations as an ITO. The Joint Decision was notified to the European Commission, which provided its Opinion on June 28th 2022³⁰. After a very thorough review of the issues raised by the European Commission, the Regulatory Authorities of Greece and Bulgaria approved the final Joint Certification Decision, certifying ICGB AD as an Independent Transmission Operator (ITO) of Natural Gas ([Decision 593/2022](#)).

In this joint decision the Regulatory Authorities asked for the appointment of a new fourth member of the company's Management Board and the designation of a Compliance Officer. Following a comprehensive evaluation of ICGB's proposal for the above positions, the NRA's jointly confirmed that ICGB is compliant with the provisions of the Certification Decision.

Network Code

[Decision 918/2019](#) approved the IGB Network Code and Tariff Regulation in alignment with the provisions of the exemption decision ([Decision 768/2018](#)). Responding to the Regulatory Authorities request for adjustment and improvement in the capacity booking procedure, the ICGB Operator submitted a draft amendment to the IGB Network Code for approval. The changes also affect the Tariff Code, Gas Transportation Agreement (GTA) for Exempted Users and Non-Exempted Users and also Virtual Trading Point (VTP) Agreement.

Following consultations, ICGB AD submitted a revised proposal introducing key changes such as:

- Improving capacity booking process.

²⁸ RAAEY approved the Investment Request with Decision E-181/2023. A public version of the Decision is available at: <https://diavgeia.gov.gr/doc/97%CE%A7%CE%9E%CE%99%CE%94%CE%9E-%CE%96%CE%A3%CE%9C?inline=true>.

²⁹ ICGB AD has cited substantial delays in the delivery of valve parks from China, crucial for the partial isolation of the system, as the principal cause for the deviation from the original timetable. Additionally, the contractor's inability to compensate for the accumulated delays further contributed to the need for modification of the Exemption Decision. These reasons were deemed reasonable by the Greek and Bulgarian Regulatory Authorities, acknowledging that they were beyond the company's control and could not have been anticipated at the time of issuing the Exemption Decision or its initial and second amendments concerning the commencement date. This joint decision to amend the directive was reached collaboratively by the Greek and Bulgarian Regulatory Authorities.

³⁰ Available online at: https://energy.ec.europa.eu/system/files/2022-09/2022_169_icgb_bg_en.pdf.

- Introduction of a VTP Agreement for Virtual Trading Point access, including defining the minimum credit limit.
- Provisions for connecting Distribution Networks and other systems as Exit Points of the IGB Pipeline.
- Additional provisions addressing the capacity overrun by Network Users.
- Terms on termination and cancellation of the GTA by both the Operator and Users.
- Procedure for guarantees
- Introduction of separate GTA prototype tailored to each category of Users, depending on their capacity reservations on the exempted pipeline section.

The Regulatory Authorities of Greece and Bulgaria issued a joint decision approving ICGB AD's request to amend the IGB Network Code (RAAEY [Decision 743/2022](#)), as the final proposal was compliant with the joint Exemption Decision, the European Regulations and the National Laws.

Daily imbalance charges methodology

According to the Exemption Decision, ICGB is obliged to follow European Regulations unless differently is defined in the Exemption Decision. As a result, Regulation (EU) 312/2014 (BAL NC) and its provisions on Daily Imbalance Charges (Chapter 5, Articles 19-23) apply. In line with this, ICGB AD has submitted to the Regulatory Authorities the methodology outlined in paragraph 1 of Article 20 of the Regulation. In terms of trading platform ICGB asked for the approval to trade on the Bulgarian Balkan Gas Hub EAD because there is a direct interconnection with the Bulgarian system, "VTP Bulgaria," which has more liquidity than ICGB. Both NRA's approved ICGB proposal to set the small adjustment at 20% because of pipeline's specific technical characteristics, limited margins for linepack gas, low liquidity on ICGB VTP and the economic incentive created by the price difference between the Italian and Bulgarian markets connected by the IGB via the TAP pipeline. RAAEY approved the methodology for calculating the daily imbalance charge of the ICGB with Decision 819/2022.

Participation in the yearly ENTSO-G auctions for gas year 2023-2024

RAAEY with [Decision E-36/2023](#) approved ICGB AD's participation in the annual capacity auctions for the gas year 2023-2024. ICGB AD had previously been granted a 25-year exemption from certain regulatory provisions (ownership unbundling, third-party access, and tariff approval) by the Greek and Bulgarian Regulatory Authorities. Despite this, ICGB must comply with the European regulations regarding the capacity that has not been exempted from the provisions of the Directive 2009/73/EC, particularly regarding capacity allocation and auction mechanisms.

The auction schedule, established by ENTSOG, set the annual capacity auctions for July 3, 2023, with transmission system operators required to announce available capacities by June 3, 2023. ICGB AD submitted its proposal to the Greek and Bulgarian regulatory bodies for approval, outlining several key aspects. These include competitive auctions for the interconnection points between the IGB and the TAP pipeline, as well as the IGB and DESFA at Komotini. The proposal also suggested short-term product offerings at the TAP interconnection until the completion of the NNGS interconnection and the provision of annual interruptible and unbundled capacity at key interconnection points.

The decision supports competitive auctions as they allow the allocation of capacity based on market demand rather than fixed capacities at each point, enhancing flexibility and efficiency. The regulatory authorities also found ICGB's approach of reserving 10% of technical capacity for short-term products for the next 5 years (and 20% afterwards) aligned with CAM NC. This decision ensures that capacity at key interconnection points is allocated transparently and efficiently, fostering competition and optimizing gas flows between Greece and Bulgaria, while complying with European energy regulations.

With [Decision 127/2023](#) and with cooperation with the Bulgarian regulatory authority EWRC, RAAEY approved ICGB's proposal to offer available non-exempted capacity at two interconnection points (IPs): the IP with the Trans Adriatic Pipeline (TAP) and the IP with the Greek Transmission Operator DESFA in Komotini. In the first quarter, all available capacity will be offered exclusively at the IGB-TAP IP. However, for the second to fourth quarters, capacity will be treated as "competing capacities" between the TAP and DESFA IPs. Bookings for DESFA will only take effect after the Komotini IP's commercial operation, scheduled for January 2024.

This arrangement provides flexibility, enabling users to book long-term capacity but only be charged when commercial operation begins. If the DESFA IP does not start on time, the booked capacity for that quarter will

be nullified. Monthly and daily capacity will remain available exclusively at the TAP IP throughout the year. The decision ensures fair competition between IPs while optimizing the use of short-term capacity products.

Derogation from Article 14 on the more effective use of transmission capacities, paragraphs 1-6 of Council Regulation (EU) 2022/2576

RAAEY with its [Decision 201/2023](#) approved "The Joint Decision of Energy Regulators regarding derogation from Article 14 of Council Regulation (EU) 2022/2576" which applies to the Interconnector Greece-Bulgaria (IGB), that spans both Bulgaria and Greece and involves multiple transmission system operators. In 2018, Bulgaria's EWRC and Greece's RAAEY granted ICGB AD exemptions from certain EU gas market rules, such as ownership unbundling and third-party access, allowing the pipeline to operate with flexibility for 25 years, starting from October 2022.

Under Regulation (EU) 2022/2576, which aims to enhance gas solidarity and coordination, ICGB AD proposed applying a firm day-ahead "use it or lose it" mechanism to the IGB pipeline, as allowed by Article 14, paragraph 7, "a." This proposal was based on market data showing that over 99% of allocated capacity from October 2022 to March 2023 was daily, with no congestion at key interconnection points (Komotini-TAP-IGB and Stara Zagora). This mechanism would ensure efficient use of capacity without disrupting the market.

After reviewing the proposal, EWRC and RAAEY agreed that implementing the day-ahead "use it or lose it" mechanism would meet the goals of Regulation (EU) 2022/2576 while considering the regulatory specifics of the pipeline and the natural gas markets in both countries. The decision allows for this mechanism to be applied at IGB's interconnection points by derogation from the general provisions of Article 14, paragraphs 1-6, ensuring the effective and reliable flow of gas between Greece and Bulgaria.

Alexandroupolis LNG Terminal

The Alexandroupolis LNG project consists of a Floating Storage Regasification Unit (FSRU) in the Thracian Sea situated approximately 17.5 km southwest of the port of Alexandroupolis and 10 km from the coastline and of a connecting pipeline to integrate with the National Natural Gas System (NNGS). With RAAEY's Decision 1580/2020, Gastrade, the operator of Alexandroupolis LNG Terminal, was granted a 25-year exemption from Article 32 of the Directive on third party access, restricted solely to the section of the Terminal for which capacity was reserved through the Market Test and from Article 41 par. 6, 8, and 10 of the Directive 2009/73/EC for the total capacity. The commercial operation of the terminal is scheduled to start in the Q1 of 2024.

The FSRU's operating model relies on the concept of borrowing and lending gas between users. For each year, the annual cargo scheduling is prepared by the TSO of the LNG terminal during which each user, based on their booked capacity, specifies the vessels they plan to bring onboard for offloading and the daily gas consumption profile they require at the Terminal's exit. Gas exchange between users is necessary to enable continuous gas offtake despite irregular vessel arrivals. Users' roles rotate, and the Terminal Operator maintains a record of borrowed and lend gas quantities. Any year-end balance, whether positive or negative, results in compensation or reimbursement among users.

For this borrowing-lending model to function smoothly, a comprehensive network of contracts was necessary between the terminal operator and the users, as well as among the users themselves, with the operator playing a pivotal role in facilitating these agreements. RAAEY's Decision 101/2022 approved key contracts as annexes to the Code of the Alexandroupolis LNG Terminal. The critical contracts are: the Terminal Use Agreement (TUA) which is signed by long-term users, the Time-Charge Agreement (SCA) for short-term users and the Inter-User Agreement (IUA), which is a key agreement governing interactions between all long-term and short-term users. Furthermore, the Capacity Exchange Agreement (CEA), which allows users to trade or exchange capacities between each other or with third parties, was also introduced. Under the CEA, either long-term or on-call users can enter into agreements for selling or exchanging gas quantities based on predefined terms set in the Terminal Code.

Terminal Access Code 1st Amendment

Following the adoption of the initial terminal access code, Gastrade S.A. (the terminal operator) proposed several additional contracts for approval to fully realize the operational framework of the terminal. These include:

- **Spot Cargo Agreement (SCA):** For short-term capacity commitments.
- **Capacity Exchange Agreement (CEA-Sales):** For sales between users or between users and third parties with prior approval from the operator.
- **Capacity Exchange Agreement (CEA-Swaps):** For transactions directly between users.

These contracts were designed to ensure that users, whether engaging in long-term commitments or short-term transactions, could interact efficiently within the borrowing-lending framework. RAAEY approved these agreements, emphasizing that they are drafted in English due to the international nature of the terminal's user base.

In detail, RAAEY introduced provisions allowing users to commit to short-term capacities through the "Spot Cargo Service." This service is for users who may not wish to commit to long-term contracts but still want access to terminal services. A specific **Spot Cargo Agreement (SCA)** was introduced to govern these interactions, outlining the responsibilities of both the opportunity user and the terminal operator. Users wishing to use this service must first sign an Inter-User Agreement (IUA) contract and ensure they have sufficient downstream rights to accept daily scheduled gas deliveries.

The Code also introduced capacity swapping mechanisms, which allow both long-term and short-term users to sell or exchange their committed capacities under specific conditions. These capacity swaps or sales can only involve the daily scheduled gas delivery quantities and not the LNG cargo itself. Two forms of capacity swaps were introduced:

- **CEA-Sales:** A sales agreement for users selling their committed daily gas quantities to third parties, subject to operator approval.

- **CEA-Swaps:** An agreement for users to swap their daily gas quantities with other users.

The final versions of these contracts were submitted to RAAEY after public consultations, ensuring transparency and non-discrimination among users.

RAAEY opened several public consultations regarding these new contracts, during which feedback was submitted by various stakeholders, including companies and users of the terminal. Gastrade S.A. responded to these comments, and adjustments were made to some contracts to address stakeholder concerns. Notably, some Users proposed that the "Evacuation Gas Penalty", which is imposed on users whose gasification profiles deviate from their capacity bookings, leaving excess gas at the terminal, should be variable, based on a market index, rather than fixed at 50€/MWh. RAAEY agreed, concluding that the penalty should not be set in the code but indexed to market conditions through a variable defined in the Tariff Regulation. Furthermore, stakeholders also suggested increasing the allowable energy and volume tolerance for LNG cargo from $\pm 2\%$ to $\pm 5\%$, reflecting broader commercial practices. However, this was rejected due to potential scheduling issues at the terminal. In addition, some adjustments were made for the "Harmonization of Deadlines" which resulted on the alignment of deadlines for user declarations and reporting with those of other Greek LNG terminals, such as Revithoussa, ensuring consistency across the Greek gas infrastructure. Furthermore, the Users requested the creation of a secondary trading platform for LNG quantities, but the terminal operator indicated that this would be studied in the future. Lastly, The Users requested the development of a specific algorithm for the allocation of time slots arrival/unloading of ships during annual scheduling. RAAEY agreed that the criteria described in the Code need further refinement to ensure transparency and equal access for users. According to the response of the Operator, the steps of the algorithm to be followed will be specified in the manual of the electronic system (TUTPS) which is under development.

The above regulatory changes were introduced in [RAAEY Decision E-215/2023](#) (Gazette B' 7073/2023).

DIORIGA GAS S.A.

In 2021, the company Dioriga Gas S.A submitted an application to RAAEY for exemption from the Articles 32, 33 and 41 of Directive 2009/73/EC. Dioriga Gas plans to establish a Floating Storage Regasification Unit (FSRU) offshore, south-west of Motor Oil's refinery in Agioi Theodoroi near Corinth. The planned storage capacity of the unit is up to 210,000 m³, with regasification capacity of 132,000 MWhs/d and an annual projected demand of 2.5 bcm of natural gas. In line with the Gas Directive a market test for indication of interest in contracting capacity before capacity allocation began. No regulatory decision regarding DIORIGA GAS was taken within 2023.

Mediterranean Gas S.A.

Mediterranean Gas S.A. is planning a Floating Storage Regasification Unit, a floating multi-point mooring/floating berth for FSRU and a subsea and onshore gas transmission pipeline to facilitate gas transport to the FSRU in Volos region. The company has submitted an application to the Regulatory Authority for Energy, seeking an exemption for the proposed gas infrastructure from specific provisions of the Directive concerning third-party access and tariffs. According to the Directive, a capacity allocation procedure Market Test prior to exemption approval is needed.

Within 2023, Mediterranean Gas S.A. submitted a request for a preliminary examination of the adjustment in the geographical area of installation and the timetable of commercial operation of the LNG project "ARGO FSRU", in accordance with the provisions of the paragraph 1.1. (c) of para. 2 of Article 17 of the Licensing Regulation. In this regard, [RAAEY Decision E-134/2023](#) approved the change in the geographical area of installation of the FSRU and the move of the date of the commercial operation of the unit from January 2023 to the Q1 of 2025.

Gas Interconnector Greece-North Macedonia

The interconnection between Greece and North Macedonia's natural gas systems was included in TYNDP of NNGS for 2017-2026 approved with Decision 236/2019. Concerning the investment recovery, RAAEY's Decision

116/2021 approving the TYNDP 2021-2030, mandates the project's incorporation into the Operator's Regulated Asset Base subject to a binding capacity allocation "market test," requiring RAAEY's consultation and approval, without leading to an increase in the NNGS tariffs.

In line with the above DESFA submitted guidelines for capacity allocation at the Greek part of the Evzoni-Gevgelija Interconnection Point, along with an Invitation for Binding Offer. All documents, including the Advanced Reservation of Capacity Agreement (ARCA), were set on public consultation. To expedite the approval process and align with the project's already-established presence in the NNGS TYNDP since 2019, the Authority opted to consolidate both the Guidelines and the Call of the Market Test into a single decision. This streamlined approach was deemed appropriate, given the project's familiarity following the bilateral agreement signed on 09.07.2021 between the Hellenic Republic and the Government of the Republic of North Macedonia.

In terms of the factor DESFA's final proposal included the factor equal to 0.5. Because of the factor's proposed level RAAEY launched a new public consultation. At the end the Authority approved a factor of 0.50 as reasonable, taking into account multiple benefits for both the Greek and North Macedonian systems such as diversification of North Macedonia's gas supply sources, promoting competition, contributing to the regional gas market development, and aligning with European Commission climate neutrality objectives by designing the pipeline to be hydrogen-compatible. The estimated investment by the NNGS Operator stands at €51.4 million, approximately 10% of the total Operator budget for NNGS development.

To ensure project construction and operation assurance, the letter of guarantee for Market Test participation was set at €100,000, roughly 70% of the maximum annual capacity, aligning with the absence of relevant comments in the public consultation.

RAAEY, through [Decision 532/2022](#), approved the Market Test Guidelines, the Invitation and ARCA, marking significant progress in advancing this pivotal gas project. Following the market test, two companies submitted binding commercial offers for capacity booking, for five and twenty-one years respectively. Both of companies signed the ARCA agreements and submitted the relevant financial guarantees. With RAAEY [Decision 68/2023](#), the Authority verified the compatibility of the Market Test with the provisions of the Market Test Guidelines and the Invitation as approved by Decision 532/2022 and concluded that the procedure provided for was fully complied with and the result of the Market Test was correctly characterized as positive by the Operator.

4.1.5 Implementation of Network Codes and guidelines

European Union's regulations are fully implemented in Greece. Regarding BAL NC, DESFA was designated as the Forecasting Party responsible for providing the transmission system operator with forecasts of network user's non-daily metered off-takes and subsequent allocations. The methodology for the forecast is yet to be developed.

Also, there are independent natural gas systems in Greece such as the Alexandroupolis LNG Terminal and systems connected to the Greek system such as TAP and ICGB, that have been granted with an exemption from specific articles of Directive 2009/73/EC. These systems implement EU Regulations unless something is differently stated in the Exemption Decision.

4.2 Competition and market functioning

4.2.1 Wholesale markets

Trading Platform

According to the provisions of EU Regulation 312/2014 (BAL NC), transmission users are responsible for balancing their inputs and outputs. Balancing rules are designed to promote a short-term wholesale gas market and trading platforms are 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.

In the period 2020-2022, RAAEY participated actively in the establishment of the regulatory framework for the operation of a natural gas 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 early 2022, the Natural Gas Trading Platform regulatory framework was successfully completed, aligning with the stipulations outlined in Law 4425/2016 and BAL NC. HENEX, as authorized by RAAEY, undertook the operation of a short-term wholesale gas market. Additionally, the "EnExClear S.A.", an entity of the Hellenic Energy Exchange Group, received approval by RAAEY as the designated Clearing House for the wholesale gas markets, in accordance with the provisions outlined in Article 19 of Law 4425/2016. In cooperation with the relevant operators, the Authority issued ten decisions governing the operation of the Natural Gas Trading Platform and the clearing of transactions.

The fundamental principles governing the framework for the operation of Trading Platform and the clearing of transactions performed therein are as follows:

- a) The Hellenic Energy Exchange (HENEX) serves as the Operator of the Trading Platform and is obliged to adhere to the requirements specified in BAL NC.
- b) Transmission Users listed in the Register of Eligible Participants in the Trading Platform (REPTP) maintained by DESFA have the right to access the Platform. A prerequisite for membership in the REPTP is that Transmission Users have access to the Virtual Trading Point (VTP) of the NNGS. All transactions executed on the Trading Platform are reported to DESFA and involve a physical delivery obligation in the VTP.
- c) DESFA retains the right to access the Trading Platform upon attaining Participant status for the purpose of purchasing or selling quantities of Natural Gas for network balancing purposes.
- d) Available products include Title Products with delivery day one Gas Day at the Virtual Trading Point of the NNGS (Hellenic VTP). Trading is done daily for the following daily Contracts: Intraday (current Gas Day D) and Day-Ahead for the next three (3) Gas Days (Gas Days D+1, D+2 and D+3, respectively)
- e) The main trading method is continuous trading which takes place from 09:30 EET to 19:00 EET. Auctions may also be held at the request of the NNGS Operator (DESFA) for network balancing purposes (08:00 EET of the calendar day until 02:00 EET of the next calendar day).
- f) The clearing of trades executed on the Trading Platform is conducted by the EnExClear³¹, operating as a Clearing House in compliance with Law 4425/2016.

Annual LNG Scheduling

Annual LNG scheduling for unloading cargos at Revythoussa is conducted through auctions. In October 2023, DESFA conducted LNG auctions for the period 2024-2038 according to the specifications set in RAAEY Decision E-146/2023. All five remaining LNG slots for 2024 were successfully auctioned. There are a total of 45 slots available for 2024, with 40 of these slots already auctioned during the October 2022 auction.

Monitoring of prices

RAAEY 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.

³¹ EnExClear was appointed as a Clearing House with [RAAEY Decision 88/2022](#) while the relevant clearing Rulebook for Transactions on HEnEx's Natural Gas Trading Platform was approved with [Decision 89/2022](#). Furthermore, RAAEY by Decisions [90/2022](#) and [91/2022](#) approved the risk management procedures of the clearing system for transactions and the imposition of measures on clearing members of the natural gas trading platform. The relevant documents (in English) can be found at the following address: <https://www.enexgroup.gr/web/guest/clearing-rulebooks>.

The publication of data on the WAIP,³² in combination with the publication of data on Balancing Gas Reference Price (RP), Balancing Gas Marginal Sell (MSP) and Balancing Gas Marginal Buy (MBP) Prices, 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.

Figure 29 presents the monthly data on WAIP for the period of January 2021 – December 2023 as well as the trend of the monthly data on WAIP against the trend of the monthly data on RP, MBP, MSP and Weighted Average Price according to NC BAL 312/2014, for the same period.

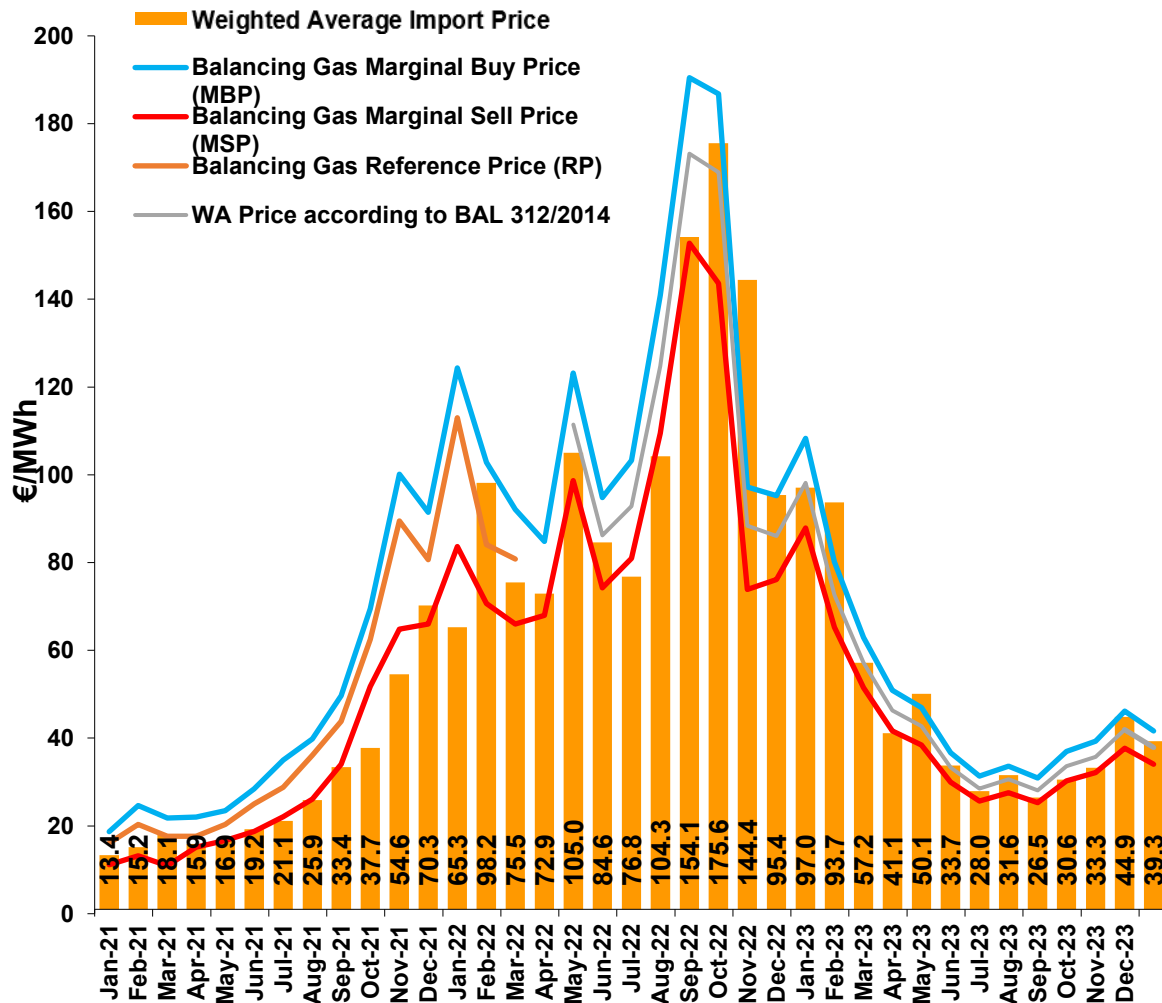


Figure 29: Price Monitoring in the Wholesale Natural Gas Market in January 2021-December 2023

The above figure illustrates a notable upward trend in the weighted average import price of natural gas from January 2021 to December 2023. Starting at relatively low levels between 10 €/MWh and 20 €/MWh in early 2021, prices steadily increase through the first half of the year. A sharper rise occurs from mid-2021, possibly related to the reduction of flows of Russian gas, with prices reaching around 38 €/MWh by October and exceeding 50 €/MWh by December. The upward momentum continues in 2022, with prices surging to over 100 €/MWh by May and peaking near 175 €/MWh during October. In 2023, the trend shifts, and prices begin to

³² For more information visit our website at: <https://www.rae.gr/en/natural-gas/market/import-prices/>

decrease, starting from 97 €/MWh in January before declining to approximately 28 €/MWh by July 2023. The year 2023 continued to present price volatility, but not at the levels of 2022.

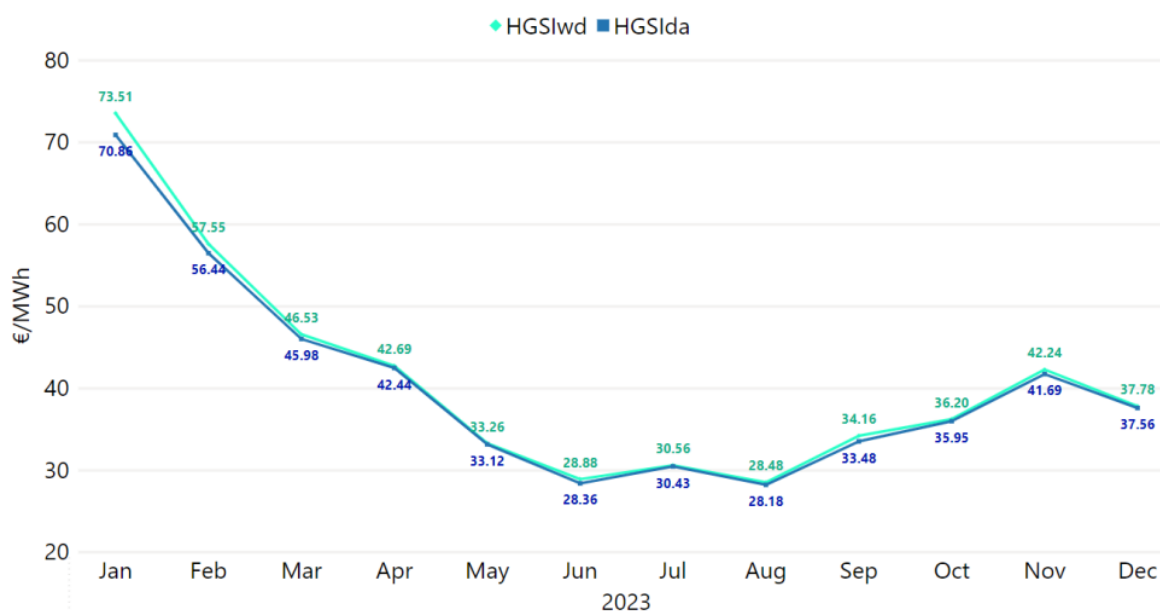


Figure 30: Day-ahead Gas Index (HGSIda) and Intraday Gas Index (HGSIwd) – Source: HENEX

The figure above illustrates the monitoring conducted by the operator of the Natural Gas Trading Platform, Hellenic Energy Exchange (HEnEx). Based on transactions made in the Natural Gas Trading Platform, HEnEx calculates and publishes various price indicators, including the Day-Ahead Gas Index (HGSIDA) and the Intraday Gas Index (HGSIDW). In 2023, the HGSIDA and HGSIDW indicators follow trends in the WAIP, which reflects natural gas prices at Greece's gas interconnection points (IPs).

An interesting shift in the gas market landscape is the substantial increase in the number of active gas importers in the country. While the number was limited until 2018, recent years have seen a surge, with the figure reaching twenty four in 2023. This surge is indicative of robust activity within the gas market.

Natural Gas Imports and Exports

Natural gas in Greece is imported through four entry points, namely Sidirokastro (Greek-Bulgarian borders), Kipi (Greek-Turkish borders), Nea Mesimvria (interconnection point of the NNGS with Trans Adriatic Pipeline) and Agia Triada (entry point from the Revithoussa LNG Terminal). As shown in Figure 31, natural gas imports decreased to 67.66 terawatt-hours (TWh) in 2023, specifically marking a significant 21.44 % decrease from 86.12 TWh recorded in 2022. Of these, natural gas exports presented a significant decrease of 43.61%, from 29,6 TWh in 2022 to 16.69 TWh in 2023.

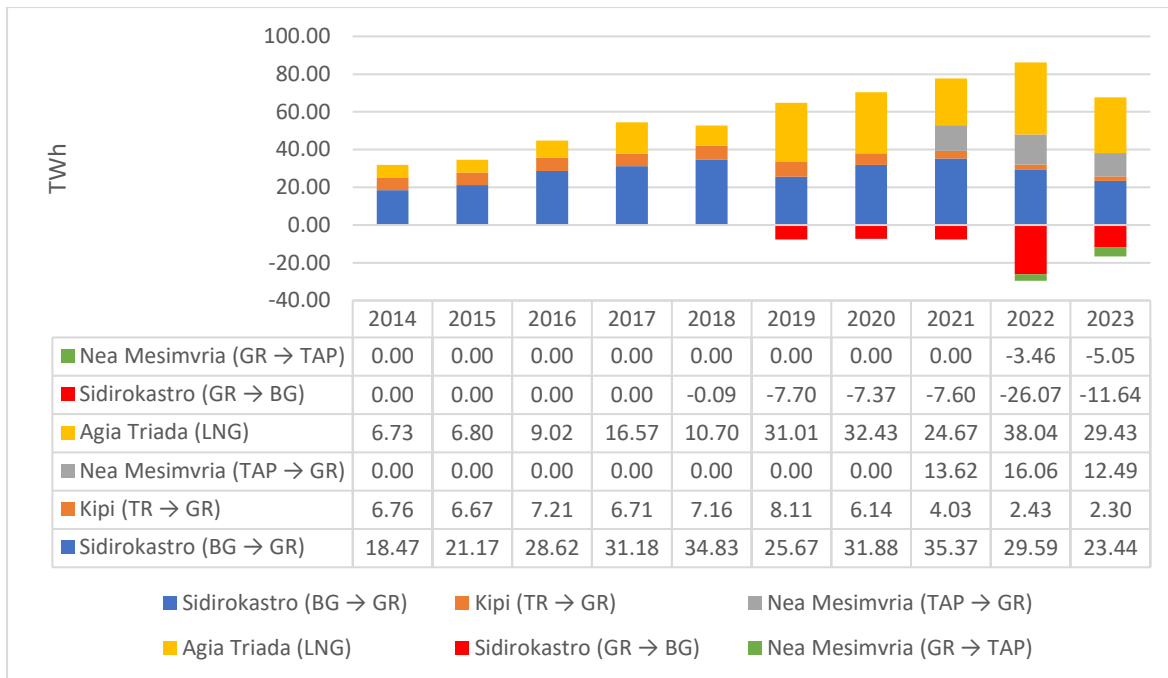


Figure 31: Quantities of natural gas (TWh) allocated at Interconnection Points (2014-2023)

The highest share of these imports flowed into the natural gas transmission system through Agia Triada (the entry point from the Revithoussa LNG Terminal), commanding a 44% share (29.43 TWh). The Sidirokastro Entry Point claimed the second spot, contributing 35% to the import volume (23.44 TWh), while the Nea Mesimvria Entry Point, the point connected to the TAP pipeline, constituted 18% of imports (12.49 TWh). Lastly, only 2% (2.30 TWh) of total imports came through Evros Kipi Entry Point.

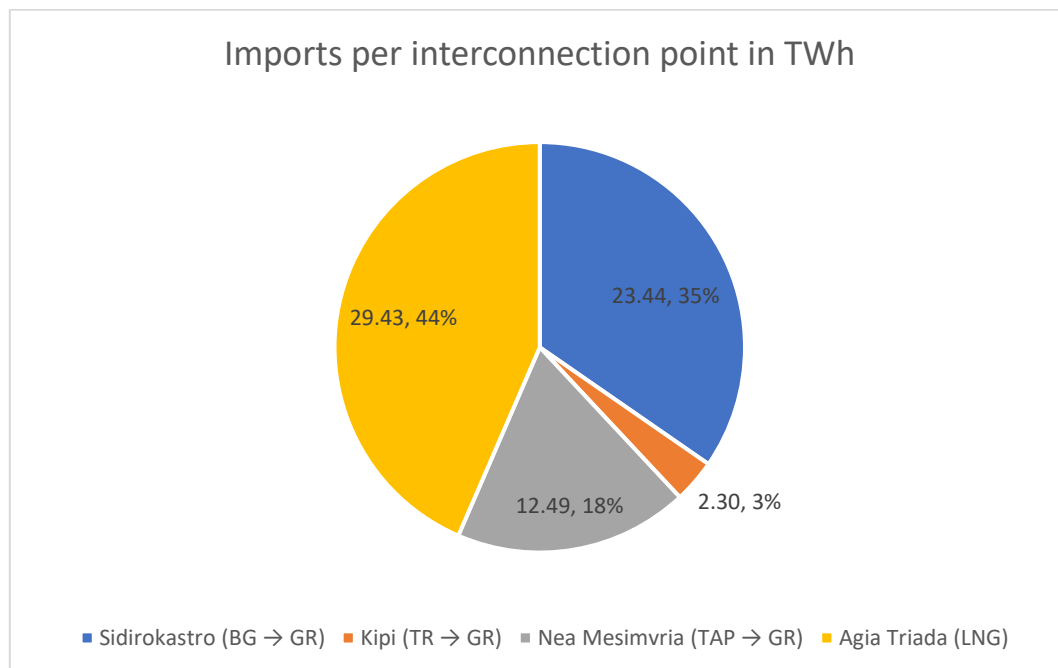


Figure 32: Percentages for imports of natural gas per Entry Point for 2023

In 2023, the LNG Terminal at Revithoussa continued to be a pivotal asset in reshaping the supply landscape for Greece and the wider region. Hosting a total of 56 LNG tankers from various origins, the terminal facilitated the offloading of 28.52 TWh of LNG through 41 tankers. This figure reflects a notable shift from the previous year's high of 39.19 TWh delivered by 78 tankers. The United States retained its position as Greece's primary LNG supplier, though with a decreased import volume of 10.75 TWh, accounting for a significant portion of Greece's LNG imports. Russia emerged prominently as the second-largest supplier in 2023, contributing 8.38 TWh. Algeria followed with 3.47 TWh, and Egypt closely matched with 3.50 TWh. Additional LNG imports were recorded from Norway (0.97 TWh), Nigeria (0.94 TWh), and Spain (0.51 TWh). This year's figures illustrate a diversification in LNG sourcing, with continued reliance on both traditional and emerging partners in the LNG market.

Country	Imported gas quantity (TWh)	(%) of total LNG imports
USA	10.75	37.69%
Russia	8.38	29.38%
Egypt	3.50	12.29%
Algeria	3.47	12.16%
Norway	0.97	3.41%
Nigeria	0.94	3.28%
Spain	0.51	1.79%
Total	28.52	100%

Table 51: Natural Gas Quantities by Country of origin in the LNG Terminal (2023)

Domestic consumption dropped from 57 TWh in 2022 to 50.91 TWh in 2023. The bulk of domestic gas consumption, totaling 67.85%, was attributed to power generators. Following closely behind were household consumers and enterprises connected to distribution networks, accounting for 21.98%. Additionally, domestic industries directly connected to the high-pressure natural gas transmission system contributed 10.17% to the consumption landscape.

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.

In 2023, the retail gas market in Greece reached its sixth year of complete liberalization. A total of 20 companies actively participated in the retail gas market, serving consumers connected to distribution networks. Tables 53 and 54 display the number of connections and consumption volume categorized by consumer type and supplier for 2023. These tables reveal that, despite holding a Supply License and being categorized as Gas Suppliers, several companies primarily serve their own industrial consumption and do not provide retail tariffs. In 2023, two acquisitions were completed: WATT & VOLT S.A. by MYTILINEOS S.A. (PROTERGIA), and KEN S.A. by VOLTON S.A.

Regarding the Supplier of Last Resort, in accordance with Decision 203/2023, the suppliers with the largest market share in each geographic area have been designated as the Suppliers of Last Resort for Natural Gas. Specifically, the following companies have been appointed: "FYSIKO AERIO" for the Attica distribution network, "ZENITH S.A." for the distribution networks of Thessaloniki, Thessaly, and Central Greece, "PROTERGIA S.A." for the Central Macedonia distribution network, "HERON" for the Eastern Macedonia and Thrace distribution network, and "EFA ENERGY" for the Deskati distribution network. These companies will serve as Last Resort Gas Suppliers for the period of one year, from 01.04.2023 to 31.03.2024.

Furthermore, DEPA and Prometheus Gas are primarily involved in the import of natural gas and they operate in the wholesale market.

At the end of 2023, a total of 48 suppliers had an active gas supply license, 15 of whom were active in the retail market of natural gas:

	Supplier Name:
1.	DEPA Commercial S.A.
2.	Prometheus Gas S.A.
3.	Mytilineos Natural Gas Supply & Trading Single Member S.A.
4.	Aegean Power S.A./Hellas Power S.A.
5.	Edison Hellas S.A.
6.	ENIMEX Gas S.A.
7.	Terna S.A.
8.	Heron Energy S.A.
9.	Gunvor International B.V.
10.	Greek Environmental & Energy Network S.A.
11.	GASELA GmbH
12.	EFA Energy S.A.
13.	Greensteel – Cedalion Commodities S.A.
14.	Mytilineos S.A.
15.	NRG Supply and Trading S.A.
16.	Sourlas S.A.
17.	Makios S.A.
18.	Elinoil Hellenic Petroleum S.A.
19.	Protergia S.A.
20.	Mytilineos S.A.
21.	Volterra S.A.
22.	VIENER S.A.
23.	Coral S.A.
24.	PNG S.A.
25.	Aegean Oil S.A.
26.	Q Capital International Partners Limited
27.	Revoil S.A.
28.	Sintez Green Energy Cyprus LTD
29.	GS Gas S.A.
30.	Nisogas S.A.
31.	Volton Hellenic S.A.
32.	Gas Technic P.C.
33.	Elpedison Power Generation Single Member S.A.
34.	Motor Oil (Hellas) Corinth Refineries S.A.
35.	Coral Gas Commercial and Industrial S.A.
36.	PPC S.A.
37.	LPC S.A.
38.	Blue Grid Gas & Power S.A.
39.	Fysiko Aerio
40.	EDA Thessaloniki-Thessalia S.A.
41.	TEKAL S.A.
42.	FGAS.EU S.A.
43.	Energy Community Hellenic Company LAR LTD
44.	ENERCOM S.R.L.
45.	Odison Production & Commerce of Energy Products Single Member S.A.
46.	Motor Oil Renewable Energy Single Member S.A.
47.	Bulgargaz EAD
48.	WATT & VOLT (Merged with PROTERGIA)
49.	KEN (Merged with VOLTON)
(50.)	Supplier of Last Resort – FYSIKO AERIO
(51.)	Supplier of Last Resort – HERON
(52.)	Supplier of Last Resort – PROTERGIA
(53.)	Supplier of Last Resort – EFA ENERGY
(54.)	Supplier of Last Resort - ZENITH

Table 52: List of Suppliers with an active gas supply license (2023)

The tables below represent the connections (Table 53) and consumption (Table 54) per category of consumers per supplier including the suppliers market shares.³³

Company	Household	Commercial	Industrial	Total	Market share
ZENITH	276,157	5,649	68	281,874	46.83%
EPA ATTIKIS (FYSIKO AERIO)	157,739	6,216	73	164,028	27.25%
MYTILINEOS (PROTERGIA)	34,385	1,129	47	35,561	5.91%
PPC	30,344	222	0	30,566	5.08%
HERON	28,313	869	74	29,256	4.86%
ELPEDISON	26,954	620	5	27,579	4.58%
NRG	18,334	715	1	19,050	3.17%
EFA ENERGY	10,248	460	3	10,711	1.78%
VOLTERRA	1,309	122	4	1,435	0.24%
KEN	1,185	36	0	1,221	0.20%
ELINOIL	358	17	0	375	0.06%
WATT & VOLT	106	1	0	107	0.02%
DEPA	0	21	39	60	0.01%
HELLENIC HALYVOURGIA	0	2	10	12	0.00%
MOTOROIL	0	0	4	4	0.00%
GREENSTEEL	0	0	2	2	0.00%
PROMETHEUS GAS	0	0	2	2	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%
NRG (SoLR)	0	0	0	0	0.00%
BA GLASS	0	0	0	0	0.00%
TOTAL	585,432	16,079	336	601,847	100.00%

Table 53: Natural gas connections per category of consumers and suppliers' market share, December 2023 (Source: Natural gas DSOs')

³³ 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.

Company	Household	Commercial	Industrial	Total	Market share
ZENITH	2,102,339	449,425	529,064	3,080,828	27.74%
FYSIKO AERIO	1,511,258	769,529	570,020	2,850,807	25.67%
MITILINEOS (PROTERGIA)	199,726	70,680	1,214,477	1,484,883	13.37%
HERON	183,999	54,414	782,564	1,020,977	9.19%
HELLENIC HALYVOURGIA	0	453	742,435	742,888	6.69%
DEPA	1	69,588	503,542	573,131	5.16%
ELPEDISON	194,729	26,436	40,279	261,444	2.35%
PPC	188,883	8,185	0	197,068	1.77%
NRG	125,507	57,528	119	183,154	1.65%
GREENSTEEL	0	0	177,195	177,195	1.60%
EFA ENERGY	74,047	23,593	14,353	111,993	1.01%
MOTOROIL	0	0	76,658	76,658	0.69%
WATT & VOLT	55,555	15,905	0	71,460	0.64%
ANOXAL	0	0	57,585	57,585	0.52%
VOLTERRA	11,472	18,591	26,987	57,050	0.51%
SOVEL	0	0	52,454	52,454	0.47%
FULGOR	0	0	45,631	45,631	0.41%
SIDENOR	0	0	42,496	42,496	0.38%
KEN	7,951	1,208	0	9,159	0.08%
ELINOIL	2,578	2,340	0	4,918	0.04%
PROMETHEUS GAS	0	0	3,638	3,638	0.03%
MNG Trading	0	0	0	0	0.00%
BA GLASS	0	0	0	0	0.00%
PETROGAZ	0	0	0	0	0.00%
TOTAL	4,658,045	1,567,875	4,879,497	11,105,417	100.00%

Table 54: Natural gas consumption (MWh) per category of consumers and suppliers' market share, 2023 (Source: Natural gas DSOs')

In 2023, competition within the gas supply sector remained stable compared to the previous year, with no significant issues affecting the gas consumers. The dominant players in the overall retail gas market, serving household, commercial, and industrial consumers, were ZENITH and FYSIKO AERIO. ZENITH represented 46.83% of the market, while FYSIKO AERIO EEE accounted for 27.25% of the market based on the number of connections. When considering consumption volume, ZENITH held a share of 27.74% and FYSIKO AERIO had a 25.67% share in the retail gas market.

Figures 33 and 34 illustrate the market shares of suppliers based on the number of connections and consumption volume in the Distribution Networks for 2023.

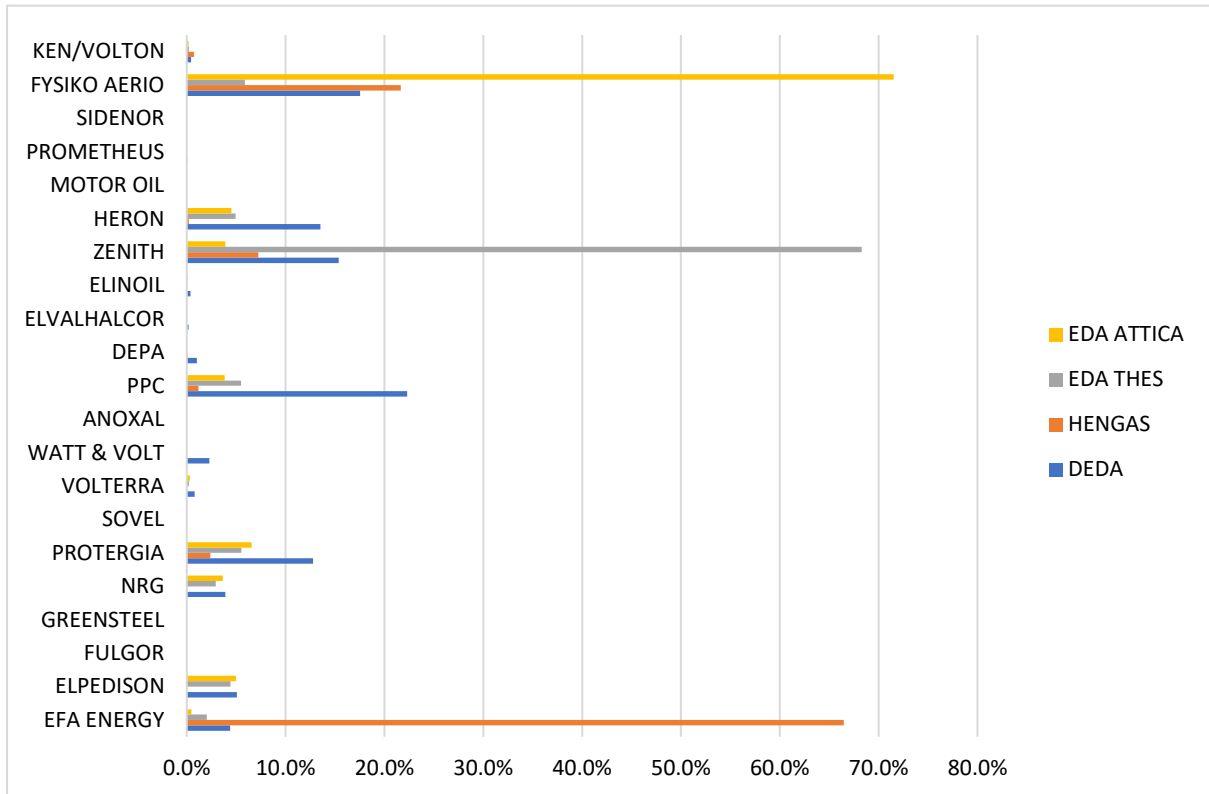


Figure 33: Suppliers' market shares per distribution system based on number of connections (2023)

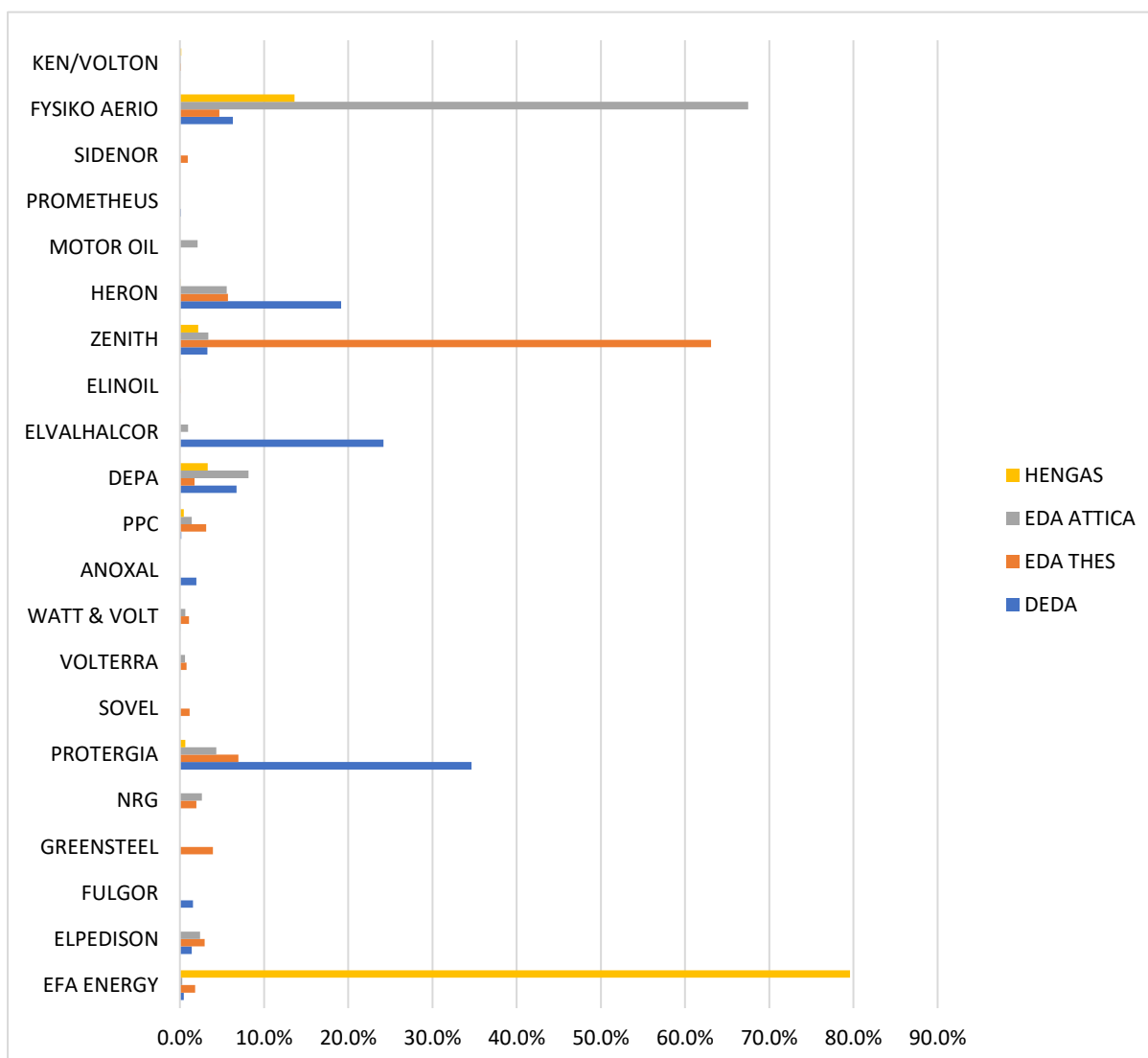


Figure 34: Suppliers' market shares per distribution system based on gas consumption volume (2023)

It's worth noting that Zenith emerged as a supplier following the unbundling of the Thessaloniki-Thessaly gas supply company, which, until January 1, 2018, held a monopoly on natural gas supply to household and small consumers in the Thessaloniki and Thessaly regions. Similarly, Fysiko Aerio originated from the unbundling of EPA Attica, which held a monopoly in the Attica region.

As evident from the figures provided above, these companies have maintained a significant market presence in the regions from which they originated. In the EDA Attica, Fysiko Aerio continues to command a substantial market share, holding 71.5% and 67.5% based on the number of connections and consumption volume respectively. In the Thessaloniki and Thessaly distribution system, Zenith retains a strong position with 68.3% and 63.1% market shares based on the number of connections and 70.90% and 60.02% based on consumption volume, respectively.

Conversely, in DEDA networks, which are relatively newer and lacked a dominant supplier, the market is characterized by a more distributed landscape among multiple suppliers. PPC has the largest market share in terms of the number of connections (22.3%), while Mytilineos leads in terms of consumption volume with a market share of 34.6%.

The HENGAS networks commenced commercial operations only in the autumn of 2022 within the Descati network. Compared to 2022, when only two suppliers (EFA Energy and Fysiko Aerio) were active, six additional suppliers (Heron, DEPA, PPC, Volton, Mytilineos, and Zenith) are now participating in these networks. Notably,

the majority of customers in this network are represented by EFA ENERGY, holding 66.5% and 79.6% market shares in terms of the number of delivery and consumption points, respectively. The next closest alternative supplier in these networks is Fysiko Aerio, with market shares of 21.7% and 13.6% in terms of delivery and consumption points, respectively.

The Herfindahl-Hirschman Index (HHI) for the entire Greek territory is estimated at 1,805 which is measured in terms of consumption volume, which falls just below the threshold of 2,000, denoting "high market concentration." However, as previously explained, when calculated individually for each Distribution Network, it becomes apparent that market concentration is significantly higher.

Table 55 provides insights into consumer switching for 2023, including corresponding consumption data. The table reveals that commercial consumers, based on the number of supplies, and household consumers, based on consumption volume, are the leading categories in terms of movement within the market.

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	585,428	54,702	9.34%	4,569,708	412,206	9.02%
Commercial	16,139	1,513	9.37%	1,677,958	108,639	6.47%
Industrial	336	9	2.68%	4,873,687	291,107	5.97%
Total number	601,903	56,224	9.34%	11,121,353	811,952	7.30%

Table 55: Consumers switching their natural gas supplier per consumer category, 2023 (Source: Natural gas DSOs' data)

Tables 56 to 59 provide a comprehensive overview of the gas retail landscape for 2023. These tables specifically detail the number of orders related to switching, termination of representation, disconnection, reconnection, and new connections. They break down the data to show the number of orders issued, the number of orders successfully executed by the DSOs, the instances where Operators executed orders beyond the stipulated time frame, and finally, the count of orders that could not be implemented. It is evident that a substantial majority of these orders pertain to household consumers.

		Number of switching orders issued	Number of switching orders executed	Number of switching orders executed beyond the stipulated time frame	Number of switching orders that were not executed
EDA ATTICA	Households	11,219	9,888	63	1,331
	Commercial	616	473	12	143
	Industrial	5	4	1	1
EDA THES	Households	43,413	36,608	49	6,805
	Commercial	975	832	0	143
	Industrial	10	4	0	6

DEDA	Households	331	331	0	0
	Commercial	8	8	0	0
	Industrial	3	3	0	0
HENGAS	Households	49	42	3	7
	Commercial	0	0	0	0
	Industrial	0	0	0	0

Table 56: Statistical data on switching orders issued to and executed by the natural gas DSOs (2023)

		Number of disconnection orders issued	Number of disconnection orders executed	Number of disconnection orders executed beyond the stipulated time frame	Number of disconnection orders that were not executed
EDA ATTICA	Households	3,684	2,483	481	1,201
	Commercial	550	372	20	178
	Industrial	1	1	0	0
EDA THES	Households	37,126	18,138	163	18,988
	Commercial	1,044	447	1	597
	Industrial	14	11	0	3
DEDA	Households	106	106	0	0
	Commercial	2	2	0	0
	Industrial	8	8	0	0
HENGAS	Households	36	24	2	12
	Commercial	3	1	0	2
	Industrial	0	0	0	0

Table 57: Statistical data on disconnection orders issued to and executed by the natural gas DSOs (2023)

		Number of reconnection orders issued	Number of reconnection orders executed	Number of reconnection orders executed beyond the stipulated time frame	Number of reconnection orders that were not executed
EDA ATTICA	Households	2,265	1,705	83	560
	Commercial	280	162	5	118
	Industrial	1	1	0	0
EDA THES	Households	20,155	17,035	202	3,120
	Commercial	343	291	4	52
	Industrial	5	5	0	0
DEDA	Households	83	83	0	0
	Commercial	0	0	0	0

	Industrial	11	11	0	0
HENGAS	Households	16	16	0	0
	Commercial	0	0	0	0
	Industrial	0	0	0	0

Table 58: Statistical data on reconnection orders issued to and executed by the natural gas DSOs (2023)

		Number of new connection orders issued	Number of new connection orders executed	Number of new connection orders executed beyond the stipulated time frame	Number of new connection orders that were not executed
EDA ATTICA	Households	10,988	7,393	2,339	3,595
	Commercial	185	128	52	57
	Industrial	0	0	0	0
EDA THES	Households	11,792	5,180	567	6,612
	Commercial	171	74	7	97
	Industrial	3	0	0	3
DEDA	Households	2,617	1,758	1,171	859
	Commercial	64	32	13	32
	Industrial	4	2	2	2
HENGAS	Households	2,103	2,009	109	94
	Commercial	43	43	1	0
	Industrial	0	0	0	0

Table 59: Statistical data on new connection orders issued to and executed by the natural gas DSOs (2023)

Overall, the retail gas market, now in its sixth year of liberalisation, shows a moderate dynamic in the Greek territory. However, the period of operation of the liberalised market is still short and, therefore, the full extent of the forthcoming changes has not yet become apparent.

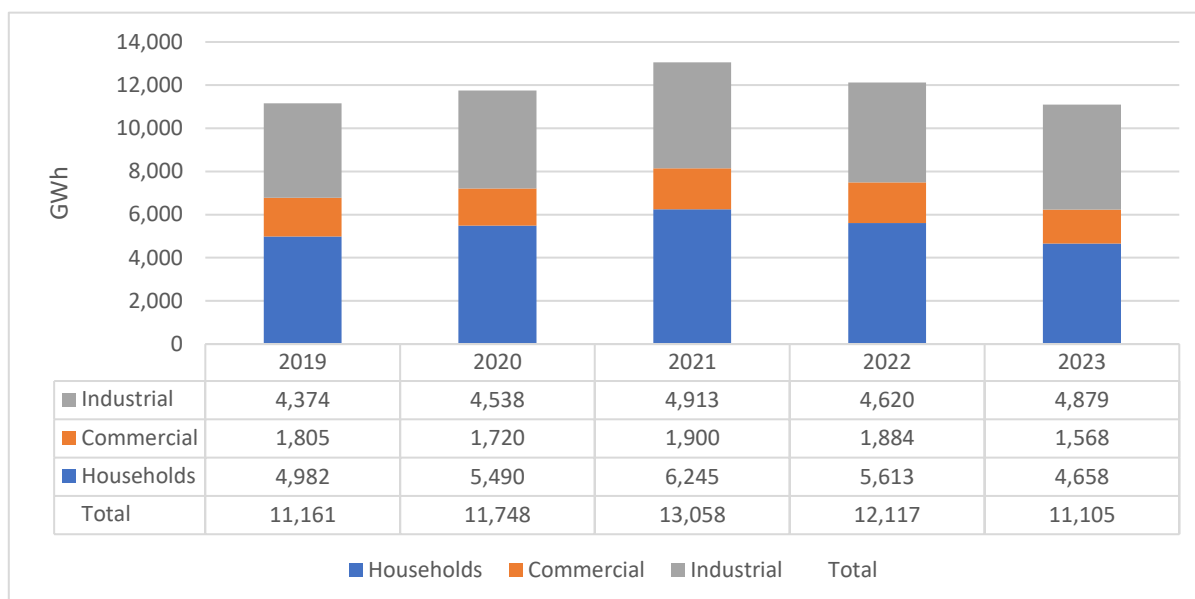


Figure 35: Natural Gas Consumption per consumers' category in the distribution networks (2019-2023)

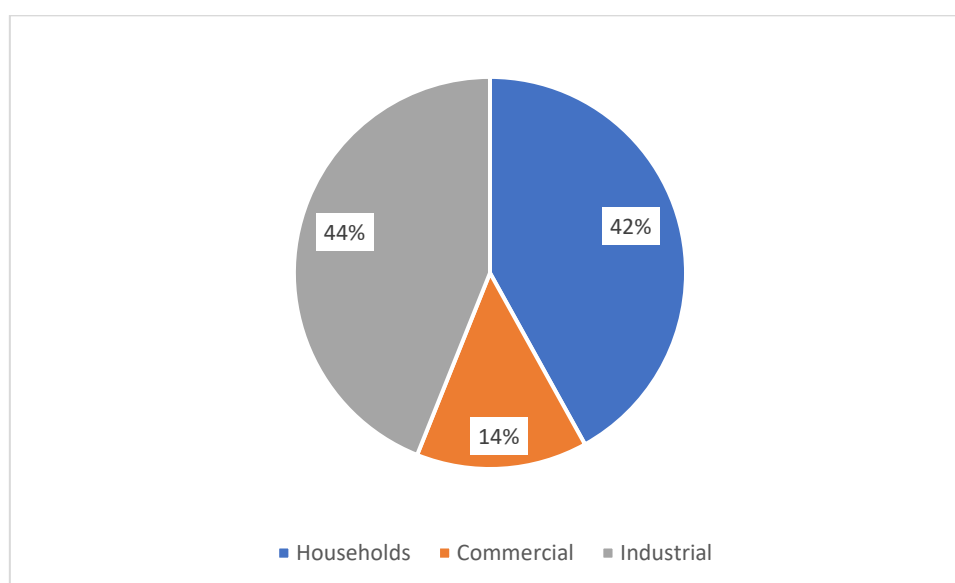


Figure 36: Natural Gas Consumption percentage per consumer category in the distribution networks (2023)

In 2022, Greece's gas consumption across various consumer categories within the distribution networks showed the following figures: households consumed 5,612,918 MWh, commercial consumers used 1,883,677 MWh, and industrial consumers consumed 4,620,155 MWh.

In 2022, Greece's gas consumption across various consumer categories within the distribution networks was as follows: households consumed 5,612,918 MWh, commercial consumers used 1,883,677 MWh, and industrial consumers consumed 4,620,155 MWh.

In 2023, there were notable changes in these consumption patterns. Household gas consumption decreased by approximately 17.01% to 4,658,045 MWh. Similarly, commercial consumers saw a 16.77% decline, with usage dropping to 1,567,875 MWh. In contrast, the industrial sector experienced a 5.61% increase in gas consumption, which rose to 4,879,497 MWh.

These figures reflect a continued decline in gas usage by households and commercial users, likely driven by efficiency measures introduced following the 2022 energy crisis and evolving market dynamics. Conversely, the growth in industrial gas consumption indicates a possible shift in production needs or other sector-specific factors.

5 SECURITY OF SUPPLY

5.1 Security of Supply in Electricity Sector

RAAEY 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, RAAEY, as the competent authority conducted the study for the “Determination of the National Electricity Crisis Scenarios in the Interconnected System of the Country”. The aforementioned study was forwarded to the European Commission and the Electricity Coordination Group of the Commission on 29.04.2022.

The study included the following:

- Brief description of the main European and national legal framework aiming to ensure the country's security of supply with electricity.
- Brief presentation of the stakeholders involved in the determination of the national electricity crisis scenarios and in general the national energy security.
- Brief presentation of the structure of the national energy market and the national and regional electricity transmission system.
- Overview of the data and the electricity demand qualitative characteristics.
- Description of the identified risks as well as of the examined crisis scenarios.
- Simulation of the scenarios, taking into account the most recent electricity demand estimates, and the latest data regarding the electricity system development projects, the interconnections and the availability of the power generating units.
- Impact assessment of the considered scenarios on the electricity production and risk assessment.

The national electricity crisis scenarios included in the study were determined based on at least the following risks, as mentioned in Article 5 par. 2 of Regulation (EU) 2019/941:

- 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.

Based on the results of the risk identification, the analysis of national and regional conditions, the results of the study of ENTSO-E on the identification of Regional Electricity Crisis Scenarios, 16 crisis scenarios were determined, examined, and simulated in cooperation with the TSO (IPTO). Namely, these concern:

1. S1 – Floods
2. S2 – Windstorms (Winter)
3. S3 – Windstorms (Summer)
4. S4 – Cold Wave / Snow
5. S5 – Droughts / Forest fires
6. S6 – Heatwave / Maintenance of upstream natural gas network
7. S7 – Earthquake
8. S8 – Earthquake / without HVDC interconnection with Italy
9. S9 – Pandemic / Human error
10. S10 – Decommissioning of lignite power plants / Delay in commissioning of new plants
11. S11 – Equipment damage

12. S12 - Decommissioning of lignite power plants / With Crete interconnection / Ptolemaida V power plant not commissioned yet
13. S13 - Decommissioning of lignite power plants / With Crete interconnection / Ptolemaida V power plant commissioned
14. S14 – Cyberattack A
15. S15 - Cyberattack B
16. S16 – Stop of Russian gas flow

Risk Preparedness Plan for the Electricity Sector of Greece

The results of the study for the “Determination of the National Electricity Crisis Scenarios in the Interconnected System of the Country” consisted the basis for the preparation of the “National Electricity Risk Preparedness Plan”, in accordance with the provisions of Article 10, 11, 12 and the Appendix of Regulation (EU) 2019/941. This plan aims to ensure the most effective approach in the prevention, preparedness, management, and mitigation of the effects of an electricity crisis. The Plan was drafted by RAAEY in cooperation with the TSO, the DSO, the Greek Energy Exchange, the National Competent Authority for Cybersecurity and the Ministry on Energy, and was approved by Decision 671/2022 in August 2022

The scope of the Plan is to identify potential risks related to the security of electricity supply and to highlight the existing and planned measures to prevent and manage of those risks.

According to Article 11 of the Regulation (EU) 2019/941, the Plan included the following:

- Short description of the technical characteristics of the interconnected transmission system of Greece, as well as of interconnections with neighboring countries.
- Quick summary of risk criteria that were adopted for the identification of risks.
- Presentation of risks that were simulated and categorized based on impacts and likelihood of occurring and resulted in the identification of national risk scenarios.
- Summary description of national electricity risk scenarios.
- Detailed description of the roles and responsibilities of the Competent Authority (RAAEY).
- Description of roles of risk management bodies.
- Description of roles of electricity crisis management bodies.
- Designation of the crisis coordinator and description of his roles.
- Detailed description of electricity crisis management mechanisms based on identified national risk scenarios.
- Description of the information flow between involved parties and entities during a possible electricity crisis.
- Description of national, regional, and bilateral procedures and measures taken, to prevent or face and mitigate the consequences of an electricity crisis.

5.2 Security of Supply in Natural Gas Sector

5.2.1 Current demand

The total consumption of natural gas in 2023, as it is determined by the deliveries to the NNGTS, amounted to 50.91 TWh, a decrease of about 10.12% compared to the consumption of natural gas in 2022 which amounted to 56.64 TWh. The consumption of natural gas in 2023 continued to decline due to the energy crisis from the highest gas demand level ever recorded in the country in 2021.

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 34.54 TWh in 2023, a decrease of 17.09% compared to 2022 (41.66 TWh).

At the same time, consumption for other uses increased by 9.27% and amounted to 16.37 TWh in 2023, compared to 14.98 TWh in 2022.

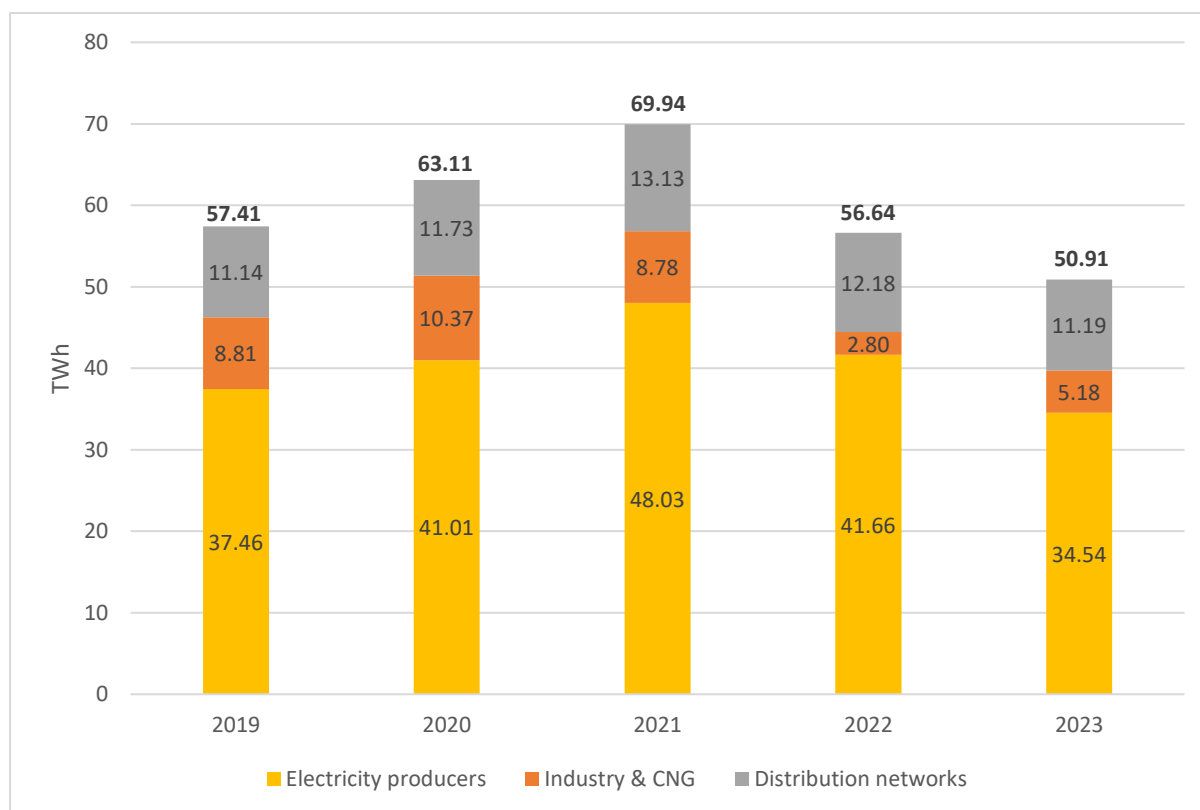


Figure 37: Natural Gas Consumption in the transmission system (Source: DESFA, 2019-2023)

RAAEY monitors the implementation of measures taken in the event of a crisis in the energy market. Especially for natural gas, RAAEY 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 Measures to safeguard the security of gas supply

National Risk Assessment

In September 2023, RAAEY, exercising its powers under Article 12, paragraph 3, of Law 4001/2011, completed the fifth revision of the National Risk Assessment Study on the security of natural gas supply in Greece. This

study was conducted in collaboration with the Operator of the National Natural Gas System (DESFA) and the Independent Electricity Transmission Operator (IPTO), in accordance with the provisions of Article 7 and Annex V of Regulation (EU) 2017/1938. The Authority notified the study to the relevant Directorate of the European Commission and the Ministry of Environment & Energy, in line with Article 12, paragraph 3, of Law 4001/2011. The study received approval through Commission Decision E-161/2023 of the Energy Sector of RAAEY.

The study analyzed all available data and information to identify and assess risks that may impact the country's natural gas supply security during the winter periods of the upcoming three years (2023-24, 2024-25, and 2025-26). It also considered the practical outcomes, economic impacts, and new insights that arose from the implementation of the previous PAP 2022. Specifically, multiple crisis scenarios were examined and simulated, which included potential gas supply disruptions combined with estimated demand profiles and exports to neighboring countries.

This analysis accounted for significant changes at both the international and national levels that may affect the energy market and gas supply security, based on findings from the Common Risk Assessment Studies conducted in 2022-2023 and the Risk Preparedness Plan carried out in 2022 under Article 7 of Regulation (EU) 2019/941.

Preventive Action Plan

RAAEY, as the Competent Authority for natural gas security of supply under Regulation (EU) 2017/1938 and Article 12 of Law 4001/2011, as amended, undertook a revision of the Preventive Action Plan (PAP) in 2023. This revision, as approved by Decision E-163/2023, considered the economic outcomes of measures implemented in PAP 2022 for winter 2022-2023, the latest demand data, information on the adequacy of the energy system's supply security both domestically and within the EU, and the technical limitations of the NNGS. Based on this assessment, the following measures/actions were identified as necessary, appropriate, and proportionate to safeguard the security of supply while optimizing the regulatory framework. The following actions are included in the PAP 2023:

- Action D1: Mechanism for prioritizing the operation of alternative fuel plants in the electricity market during a Level 3 gas crisis, to be activated by decision of the Crisis Management Group (CMG).
- Action D2: Introduction of provisions to encourage prudent use and limit unnecessary consumption of gas during a crisis.
- Action D3: Priority natural gas supply to certain critical industries.
- Action D4: Provision for exceptional modifications to the LNG Offloading Schedule.
- Action D5: Increase diesel stock in natural gas fueled electricity production plants with provisions for potential fuel switching.
- Action D6: Exceptional capacity arrangements at NNGS Entry Points provided by the Operator.

The 2023 PAP also includes previously approved measures such as "Interruptible Consumers" (Article 73, para. 5, Law No. 4001/2011) and "Use of Alternative Fuel" (Article 73, para. 4). These measures remain valid until they are revised or until the four-year period established by Regulation (EU) 2017/1938 (Article 9, paragraph 11) elapses.

The PAP 2023 was based on EU-level studies, results from the 2023 Common Risk Assessments (CRA) of the Trans-Balkan, Caspian, Ukrainian, and the 2022 CRA of the Algerian Risk Group (of which Greece is a participant per Regulation (EU) 2017/1938), and the 2023 National Risk Assessment Study for natural gas prepared by RAAEY and completed in September 2023.

Emergency Plan

Additionally, RAAEY, as the Competent Authority, approved the new Emergency Plan 2023 (EP 2023) by Decision E-182/2023. This plan includes measures/actions from the PAP, and is applicable during crisis situations that affect or risk affecting the Greek natural gas market's stability or supply security as per Regulation (EU) 2017/1938. This approval was based on a proposal by the NNGS Operator.

The Emergency Plan was prepared in accordance with Article 10 and Annex VII of the Regulation, specifically:

- **(a)** It is based on the crisis levels outlined in Article 11, paragraph 1 of the Regulation.

- **(b)** It defines the roles and responsibilities of Gas Companies, the Electricity Transmission System Operator (where applicable), and Industrial Gas Customers, including relevant electricity producers.
- **(c)** It specifies the roles and responsibilities of the Competent Authorities and other entities assigned specific tasks as per Article 3, paragraph 2 of the Regulation.
- **(d)** It ensures adequate response capabilities for natural gas companies and large gas customers, including electricity producers, for each crisis level indicated in Article 11, paragraph 1.
- **(e)** It establishes detailed procedures and measures for each crisis level in Article 11, paragraph 1, including corresponding information sharing plans.
- **(f)** It describes mechanisms to be used if assistance from the Union or Member States is required.
- **(g)** It outlines information obligations for Natural Gas undertakings at each crisis level indicated in Article 11, paragraph 1.
- **(h)** It designates crisis management teams and defines their roles.
- **(j)** It includes a list of predefined actions to ensure gas availability in the event of an Emergency.

Finally, the approved Emergency Plan includes a merit order of curtailment during a crisis and a methodology for prioritizing supply interruptions, in particular for those consumers listed as "Important Industries," in line with Action D3 of the PAP 2023.

RAAEY has notified the Emergency Plan 2023 to the relevant Directorate of the European Commission and the Ministry of Environment & Energy, in compliance with Article 12, paragraph 3, of Law 4001/2011, as amended. The Emergency Plan 2023 was published in the Official Government Gazette (Gazette B' 6453/13.11.2023).

RAAEY's timely preparation and notification of all required studies and regulatory acts to the EU Commission by the October 31, 2023, deadline ensured full compliance with Regulation (EU) 2017/1938, addressing the EU Pilot case (2023)10501 on natural gas security of supply measures.

Security of Supply levy

Finally, under Article 73A of Law 4001/2011, the Security of Supply Levy per natural gas Customer category, initially set by Decision 888/2022 to recover 2022 PAP action costs, was adjusted in Decision E-81/2023. This revision sets the 2023 levy, with subsequent years' levies adjusted independently up to 2027 to account for future PAP costs. Following a public consultation, RAAEY issued Decision E-221/2023, determining the maximum allowable Security of Supply Account (SSA) limit and the levy's unitary charges per Customer category, reflecting the new conditions outlined in PAP 2023.

	Interruptible consumers	Electricity producers	Other consumers	Protected consumers
2023	0	0.50	0.40	0.57
2024	0	+ 0.44*	+ 0.35*	+ 0.50*
2025	0	+ 0.44*	+ 0.35*	+ 0.50*
2026	0	+ 0.44*	+ 0.35*	+ 0.50*
2027	0	+ 0.41*	+ 0.33*	+ 0.47*
*Differential increment based on real costs of the PAP actions				

Table 60: Security of supply levy per year in €/MWh

5.2.3 Projected demand

DESFA's projections (Demand Forecast Study³⁴) of natural gas demand for the next ten years (2023 to 2032) are summarized in the table below.

³⁴ Available online: https://www.desfa.gr/userfiles/5fd9503d-e7c5-4ed8-9993-a84700d05071/f_Demand%20Forecast%20Study%202023-2032.pdf

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Power generation	3,619	4,412	4,345	4,206	4,255	4,360	4,500	4,245	4,206	3,990
Consumers connected to High Pressure	628	693	698	1,235	1,241	1,256	1,253	1,254	1,254	1,258
Distribution Networks	1,251	1,289	1,409	1,469	1,504	1,549	1,582	1,615	1,649	1,688
Reverse flow / Exports	2,578	4,201	4,739	5,162	5,262	5,362	5,462	5,562	5,401	5,501
Total	8,076	10,595	11,191	12,072	12,262	12,527	12,797	12,676	12,510	12,437

Table 61: Future natural gas demand in mNm³ (DESFA's estimates)

5.2.4 Risk Groups

Based on the Annex I of Regulation (EU) 2017/1938, RAAEY participates in the currently active Algerian, Ukrainian, Caspian Risk Groups and the Trans-Balkan Risk Group. 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 Common Risk Assessment (CRA) studies, capture the regional dimension of Preventive Action Plans and Emergency Plans and draw up solidarity arrangements. More specifically, RAAEY, as the Competent Authority, participates in the drafting of the Common Risk Assessment studies within the above Risk Groups, in order to identify and assess multiple scenarios. These Common Risk Assessment studies, as stipulated in the Regulation, should be updated every four years, or more frequently if warranted by circumstances.

Furthermore, in the case of the Trans-Balkan Risk Group (Trans-Balkan region: Bulgaria, Greece, Hungary, Romania), RAAEY, in its role as the Competent Authority, acts as the coordinator of the Risk Group for the development of the CRA including the tasks: i) setting the project schedule, ii) organization of meetings, iii) coordination of the drafting of minutes, iv) call for written contributions and exchange of information within the Risk Group, v) coordination of tasks and vi) final drafting of the CRA and notification to the Commission. To ensure the proper operation of the Risk Group, the Competent Authorities within the Risk Group have formulated a Cooperation Mechanism, as per Regulation (EU) 2017/1938. This Mechanism, duly notified to the Commission, establishes a framework for cooperation to facilitate the effective functioning of the Risk Group, with decisions made by consensus among Member States through their Competent Authorities.

The completion of the Common Risk Assessment (CRA) Study for the Trans-Balkan Risk Group in late 2022 marked a significant milestone. The Study comprehensively identified and assessed all relevant risk factors with regional implications. Given the ongoing situation stemming from Russia's invasion in Ukraine and the resulting reduction in Russian gas supply to the EU, it was agreed by consensus by all affected Risk Groups to identify the full interruption of Russian gas imports as the main source of risk and thus not base the scenarios on the collection of expert opinion through the questionnaire on sources of risk. This specific risk (S-1: source -1 where the source of gas is Russia) that heavily affects the system in terms of unserved demand, was examined thoroughly through a series of sub-scenarios to represent impact of demand reduction by MS, along with few scenarios based on infrastructure risks (i.e. possible disruption of other infrastructure). More specifically, eight subscenarios (8) were developed, reflecting different gas crisis management approaches, the level of interconnectors use and finally special assumptions for the storage for the next winter. The above subscenarios were simulated under six (6) different demand scenarios to simulate climatic years. Moreover, for 2 specific scenarios, a sensitivity analysis was performed to assess the impact of achieving different demand reduction targets (5%, 10% and 15%). The risk was estimated on the basis of the impact assessment combined with the scenarios' likelihood.

Due to the conditions caused as a result of geopolitical situation in relation to the natural gas flows to Europe in winter 2022-2023 and the common risk between MS, the Trans-Balkan Risk Group, whose coordinator, as mentioned above, is Greece, in collaboration with the Joint Research Centre (JRC) and the Ukraine, Belarus, Libya and Caspian Risk Groups co-decided in 2022 to conduct a Common Risk Assessment Study. The Study was completed by the JRC in November 2022 and shared with the MS of the above Risk Groups.

In 2023, two additional Common Risk Assessment Studies, involving Greece, were completed and submitted to the European Commission. The "Caspian" Risk Group study, coordinated by Hungary's Ministry of Energy, was finalized and submitted on August 29, 2023, and shared with all participating Member States, including Greece. Additionally, the Ukraine Risk Group study, led by Italy, was completed and submitted to the EU in June 2023.

5.2.5 Keeping gas storage stocks in neighboring Member States

Regulation (EU) 2022/1032 stipulates that Member States lacking underground gas storage facilities must establish arrangements for storing natural gas in facilities of other Member States with such storage capacities, with a minimum of 15% of their average annual gas consumption in the preceding five years or the maximum technically feasible quantity.

To adhere to this regulatory obligation, RAAEY introduced Action 3 in the Preventive Action Plan (PAP) 2022. Under this action, Obligated Gas Suppliers, either directly or through third-party gas suppliers, are mandated to book storage capacity and store the specified gas quantities in underground storage facilities of neighboring Member States. The stored gas is to be withdrawn at a constant daily rate and made available to the Greek market at the Gas Trading Platform of the Hellenic Energy Exchange (HENEX). This action spans from November 2022 to March 2023.

Initial cost estimates related to the storage obligation were included in the PAP. However, gas supply costs are not compensated, as they will be used by the Obligated Gas Suppliers during the winter period. To mitigate risks associated with early gas supply and costs, an optional Contract for Differences (CfD) has been introduced. The CfD covers Obligated Gas Suppliers if the commercial gas price at the time of withdrawal is lower than the supply price during the injection period and protects consumers from exceptionally high prices during withdrawal. The methodology for determining the strike price for the CfD and related capital costs were established by RAAEY Decision 814/2022.

However, practical challenges emerged, as simultaneous injection and withdrawal were hindered by the Italian Gas Storage Code, while significant difficulties were encountered in withdrawing gas from storage facilities in Bulgaria and Italy. In response, RAAEY issued Decision 839/2022 to facilitate the fulfillment of Action 3 obligations by allowing the import of daily gas quantities into NNGTS and enabling the swapping of stored gas with quantities from the Obligated Gas Supplier's commercial portfolio.

Finally, under Decision 911/2022, RAAEY approved the Standard Contract for the compensation and charging of the Obligated Gas Suppliers of Action 3 within the framework of its statutory powers.

5.2.6 Solidarity Mechanism

The EU Regulation 2017/1938, commits EU member states to the obligation to establish, with their neighboring EU member states, solidarity mechanisms that will be implemented in the event of an extreme natural gas supply crisis, in their domestic markets. The solidarity mechanisms aim to ensure that the so-called "vulnerable consumers" of the EU Member States' markets, such as households, hospitals, schools, etc., will continue to have access to the supply of natural gas even in the event of extreme conditions prevailing in the power supply. In this context, the EU Member States were invited by the EU to adopt the necessary bilateral agreements with the necessary legal, technical and financial elements (Regulation 2018/177).

For the development of the Plan and the solidarity measures, as well as for the preparation of the signing of agreements establishing solidarity mechanisms between Greece and its neighboring European EU member states (Italy and Bulgaria), RAAEY collaborated with the National System Operator Natural Gas S.A. (DESFA), the Independent Electricity Transmission Operator (IPTO), the Ministry of Environment and Energy and the Ministry of Foreign Affairs. In the period 2020 – 2022, two draft agreements establishing Solidarity mechanisms (Greece – Italy and Greece – Bulgaria) were prepared and proposed to the competent authorities. The signing of the agreements establishing bilateral solidarity mechanisms is the exclusive responsibility and decision of the political leaders of the member states.

Up to date, only 7 bilateral agreements establishing bilateral solidarity mechanisms have been signed between EU member states, in respect to the European Regulation 2017/1938. More specifically, the following have been

signed: the Denmark-Germany agreement (14.06.2023), the Germany-Austria agreement (20.12.2021), the Estonia-Latvia agreement (01.04.2022), the Lithuania-Latvia agreement (10.03.2022), the Austria-Slovenia agreement (22.04.2023), the Finland-Estonia agreement (25.04.2023) and the Denmark-Sweden agreement (08.05.2023). We recall that the total number of bilateral agreements that have to be signed between neighboring EU member states required for the mechanisms to function effectively throughout the Union territory, is 46.

The European Commission in December 2021, in its proposal to amend Regulation 2017/1938, included harmonized clauses showing solidarity between EU member states, directly applicable, in the absence of bilateral agreements establishing a solidarity mechanism between member states. Its proposals were implemented in the new EU regulation (EU) 2022/1032.

Bilateral agreements from 2022, became clear that they were no longer the priority for the EU's energy security policy, although they functioned and continue to function "complementary" to the EU's emergency measures to avoid the energy crisis. With its new package of proposals, called "REPowerEU", the European Commission adopted measures to deal with the possible supply crisis of the European natural gas markets by adopting the rule of reducing the domestic consumption of EU member states by 15% compared to their average consumption in the previous five years, adopted the policy of joint purchases of liquefied natural gas from the international markets by establishing electronic trading platforms and obliged the member states that have natural gas storage facilities to proceed with the increase of their strategic natural gas reserves to 90% of their total storage capacity before the start of the winter seasons in November. In addition, the European Commission proceeded to sign memoranda of cooperation and agreements of intent to buy and sell natural gas (Letter of Intents) with third countries (Egypt, USA, Algeria etc). The Commission set a medium-term goal of zero purchases of Russian natural gas by European companies by the year 2027. All these developments were discussed in the context of the work of the Gas Coordination Group.

On 24th November 2022 the Greek Minister of the Environment and Energy with the Bulgarian Minister of Energy signed a Memorandum of understanding between the Ministry of Environment and energy of the Hellenic Republic and the Ministry of Energy of the Republic of Bulgaria on cooperation in the security of gas supply and gas storage.

Within 2023, RAAEY issued Decision 200/2023, providing an exemption for DESFA from the provisions of par. 1-6 of Article 14 of Council Regulation (EU) 2022/2576 of 19 December 2022 enhancing solidarity through better coordination of gas purchases, reliable price benchmarks and exchanges of gas across borders, according to par. 7 of Article 14. A similar exemption was granted for the ICGB AD, the company operating the Greece-Bulgaria interconnector, through a Joint Decision of RAAEY³⁵ (Decision 2021/2023) and the Bulgarian regulatory authority EWRC.

³⁵ Available online in English and Greek at:

<https://diavgeia.gov.gr/doc/%CE%A8%CE%94%CE%9A%CE%A5%CE%99%CE%94%CE%9E-%CE%99%CE%A8%CE%9D?inline=true>

6 Lists

6.1 List of tables

Table 1: Required Revenue of National Transmission System 2022 in real terms based on RAAEY Decision 946/2022 (amounts in €).....	18
Table 2: Key financial figures of IPTO S.A.....	18
Table 3: Regulated Tariffs applied for the use of the transmission system in 2022 (Decision 643/2022).....	19
Table 4: Main parameters of WACC- IPTO S.A. - 2022-2025 (Decision 587/2022).....	19
Table 5: Allowed Revenue 2021-2024 for HEDNO S.A.....	20
Table 6: Key financial figures of HEDNO S.A.	20
Table 7: Main parameters of WACC- HEDNO S.A. - 2021-2024 (Decision 1566/2020)	21
Table 8: Regulated tariffs applied for the use of the distribution system in 2020 and 2021 (from 1st April 2020).....	21
Table 9: Installed Capacity and Production by fuel, including RES, in the Interconnected System in 2023	40
Table 10: Active electricity suppliers in 2023	45
Table 11: Total number of connections per Supplier and Consumer Category in the interconnected Network (31.12.23, Source: HEDNO S.A. for LV and MV, IPTO S.A. for HV)	46
Table 12: Electricity Consumption per Supplier and Consumer Category (LV & MV) in the interconnected Network (2023, MWh, Source: HEDNO S.A.)	47
Table 13: Electricity Consumption per Supplier of HV transmission consumers in the interconnected Network (2023, GWh, Source: IPTO S.A.)	48
Table 14: Switching, disconnection, reconnection and new connection orders issued to and executed by HEDNO per consumer category (LV & MV) in the interconnected System (2023, Source: HEDNO S.A.)	50
Table 15: Average Tariffs of Household Electricity Products. 2023 (€/MWh) after the application of subsidies from the Energy Transition Fund	53
Table 16: Number of metering points, consumption volume and switching rates per consumer category in the interconnected system's electricity retail market in 2023	56
Table 17: Total RES/HECHP installed capacity and percentage change (2020-2023).....	65
Table 18: Total RES/HECHP generation in GWh (2020-2023).....	66
Table 19: RAAEY licensing activity in 2023.....	68
Table 20: Revoked RES licenses per technology (2023).....	69
Table 21: Licensing progress of RES projects (2023).....	70
Table 22: Production licenses issued to storage technologies within 2023	71
Table 23: Administrative reference tariffs for RE projects of Law 4414/2016, Table 1 of Article 4.1(b)	74
Table 24: Administrative reference tariffs for HECHP projects of Law 4414/2016, Table 1 of Article 4.1(b).....	76
Table 25: Timing, technologies and auctioned capacities of RES auctions planned for 2022 – 2024 ..	79
Table 26: Competitive auction participation fee	79
Table 27: Competitive auction participation fee	80
Table 28: Tendered capacity per electricity storage competitive auction (2023)	80
Table 29: Results of the first competitive auction for energy storage power plants	82

Table 30: New RES Levy Unit Charges (2021)	84
Table 31: Structure of the Main RES' Financing Account (ΛΓ1 & ΛΓ2, in MEUR, 2021-2022, Source DAPEEP)	85
Table 32: Structure of subaccount for New RES & HECHP Projects (ΛΓ3, in MEUR, 2022, Source DAPEEP)	85
Table 33: PV power plant curtailments.....	89
Table 34: Wind power park curtailments	89
Table 35: Energy storage curtailments	90
Table 36: Electricity Generation in Non-Interconnected Islands for 2023 (Source: HEDNO).....	92
Table 37: RES Electricity Generation and installed capacity per technology in Non-Interconnected Islands for 2023 (Source: HEDNO)	93
Table 38: Companies active in the electricity supply market of Non-Interconnected Islands (2023)..	94
Table 39: Total number of meters per Supplier and Consumer Category (LV & MV) in the Non-interconnected Islands (31.12.23, Source: HEDNO S.A.)	95
Table 40: Electricity Consumption in kWh per Supplier and Consumer Category (LV & MV) in the Non-interconnected Islands (2023, Source: HEDNO S.A.)	96
Table 41: Number of metering points, consumption volume and switching rates per consumer category in the Non-interconnected Islands' electricity retail market in 2023.....	98
Table 42: Required Revenue per basic NNGS service (€/year).....	102
Table 43: Main parameters of WACC- DESFA S.A. - 2024-2027 (E-69/2023)	102
Table 44: Allowed Revenue per basic NNGS service for the year 2024 (€)	102
Table 45: Natural Gas Transmission and LNG Tariffs for 2024	103
Table 46: Required revenue – EDA / DEDA.....	105
Table 47: Required revenue – HENGAS S.A	105
Table 48: Capacity and energy tariffs for EDAs 2024.....	106
Table 49: Capacity and energy tariffs for HENGAS 2024	106
Table 50: Capacity and energy tariffs for DEDA 2024.....	107
Table 51: Natural Gas Quantities by Country of origin in the LNG Terminal (2023)	122
Table 52: List of Suppliers with an active gas supply license (2023).....	125
Table 53: Natural gas connections per category of consumers and suppliers' market share, December 2023 (Source: Natural gas DSOs')	126
Table 54: Natural gas consumption (MWh) per category of consumers and suppliers' market share, 2023 (Source: Natural gas DSOs')	127
Table 55: Consumers switching their natural gas supplier per consumer category, 2023 (Source: Natural gas DSOs' data)	130
Table 56: Statistical data on switching orders issued to and executed by the natural gas DSOs (2023)	131
Table 57: Statistical data on disconnection orders issued to and executed by the natural gas DSOs (2023).....	131
Table 58: Statistical data on reconnection orders issued to and executed by the natural gas DSOs (2023).....	132
Table 59: Statistical data on new connection orders issued to and executed by the natural gas DSOs (2023).....	132
Table 60: Security of supply levy per year in €/MWh.....	139
Table 61: Future natural gas demand in mNm ³ (DESFA's estimates)	140

6.2 List of figures

Figure 1: Evolution of the weighted average selling price in the Day Ahead and Intraday Markets, over the period of the implementation of the Temporary Mechanism (08.07.2022-31.12.2023).	34
Figure 2: Evolution of the sales income and amount returned from the Day Ahead and Intraday Markets, over the period of the implementation of the Temporary Mechanism (08.07.2022-31.12.2023).	34
Figure 3: Evolution of the average hourly Energy Mix over 2023 for the DAM Schedule.	38
Figure 4: Evolution of the average hourly Energy Mix over 2023 for the Market Schedule.	38
Figure 5: Evolution of the average hourly Energy Mix over 2023 for the ISP Schedule.	39
Figure 6: Monthly Production by Generation Fuel in 2023 (Interconnected System).....	40
Figure 7: Electricity generation in GWh by energy source in 2023 (Interconnected System).....	42
Figure 8: Evolution of Electricity Trading Balance of physical flows at interconnection points during 2022 and 2023 (GWh).....	42
Figure 9: Physical Electricity Flow Imports and Exports (GWh) 2023	43
Figure 10: Market shares of suppliers based on number of meters in the retail electricity market, Interconnected System (LV & MV, 2023, Source: HEDNO S.A.)	48
Figure 11: Market shares of suppliers based on consumption in the retail electricity market, Interconnected System (LV & MV, 2023, Source: HEDNO S.A.)	49
Figure 12: Electricity connections supplied under the Universal Service Suppliers, Interconnected System (LV & MV, 2023, Source: HEDNO S.A.)	50
Figure 13: Electricity consumed under the Universal Service Suppliers, Interconnected System (MWh, LV & MV, 2023, Source: HEDNO S.A.)	50
Figure 14: Electricity prices for household consumers – Eurostat (Consumption Band DC: 2,500 kWh < Consumption < 5,000 kWh) – Energy Component.....	53
Figure 15: HEPI Index by e-Control, MEKH and VaasaETT – Total electricity price paid by consumers.....	54
Figure 16: MV & LV consumer switching among all suppliers for the entirety of Greek electricity markets (both Interconnected System and NII) in 2023, based on the number of connections.	56
Figure 17: Correlation between wholesale and retail electricity prices in €/MWh (2023) – RAAEY analysis.....	58
Figure 18: Complaints submitted to MyRAE platform per electricity supplier (2023)	58
Figure 19: Complaints submitted to MyRAE platform per gas supplier (2023)	59
Figure 20: Electricity Weighted Complaint Index (2023)	60
Figure 21: Natural Gas Weighted Complaint Index (2023).....	60
Figure 22: Complaints submitted to RAAEY outside MyRAE online platform (2023).....	61
Figure 23: RES/CHP Generation percentage excluding large hydroelectric plants per technology (2020-2023).....	66
Figure 24: RES Financing Account’s Progress (2020-2023, Source DAPEEP)	86
Figure 25: Market shares of suppliers based on number of meters in the retail electricity market, Non-interconnected Islands (LV & MV, 2023, Source: HEDNO S.A.)	97
Figure 26: Market shares of suppliers based on consumption in the retail electricity market, Non-interconnected Islands (LV & MV, 2023, Source: HEDNO S.A.)	97
Figure 27: Electricity connections supplied under the Universal Service Supplier, Non-interconnected Islands (LV & MV, 2023, Source: HEDNO S.A.).....	99
Figure 28: Electricity consumed under the Universal Service Supplier, Non-interconnected Islands (MWh, LV & MV, 2023, Source: HEDNO S.A.).....	99
Figure 29: Price Monitoring in the Wholesale Natural Gas Market in January 2021-December 2023	119

Figure 30: Day-ahead Gas Index (HGSlda) and Intraday Gas Index (HGSldw) – Source: HENEX	120
Figure 31: Quantities of natural gas (TWh) allocated at Interconnection Points (2014-2023)	121
Figure 32: Percentages for imports of natural gas per Entry Point for 2023	121
Figure 33: Suppliers’ market shares per distribution system based on number of connections (2023)	128
Figure 34: Suppliers’ market shares per distribution system based on gas consumption volume (2023)	129
Figure 35: Natural Gas Consumption per consumers’ category in the distribution networks (2019- 2023)	133
Figure 36: Natural Gas Consumption percentage per consumer category in the distribution networks (2023)	133
Figure 37: Natural Gas Consumption in the transmission system (Source: DESFA, 2019-2023)	137

6.3 List of abbreviations

ACER	Agency for the Cooperation of European Energy Regulators
aFRR	Automatic Frequency Restoration Reserve
AMP	Average Billing Price
AR	Allowed Revenue
ARCA	Advanced Reservation Capacity Agreement
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
bFZK	Conditional firm freely allocable capacity
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
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.
DNDP	Distribution Network Development Plan
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
Eoi	Expression of Interest
EPA	Natural Gas Supply Company
ESC	Electricity Supply Code
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
FSU	Floating Storage Unit
GCV	Gross Calorific Value
GRIT	Greece-Italy
GW	Gigawatt
GWh	Gigawatthours
HECHP	Combined Heat and Power
HECHP	High Efficiency Combined Heat and Power
HEDN	Hellenic Electricity Distribution Network
HEDNO S.A.	Hellenic Electricity Distribution Network Operator S.A.
HEDNOC	Hellenic Electricity Distribution Network Code
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
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
IUA	Inter-User Agreement
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
MCP	Market Clearing Price
MCV	Maximum Calorific Value
MEUR	Million Euro
mFRR	Manual Frequency Restoration Reserve
MIPs	Major Importance Projects
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
NG	Natural Gas
NII	Non-interconnected island
NGGS	National Natural Gas System
NGGTS	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
PPA	Power Purchase Agreement
PPC S.A.	Public Power Corporation S.A.
PSOC	Public Service Obligation Compensation
PV	Photovoltaic
RAB	Regulatory Asset Base
RAAEY	Regulatory Authority for Energy, Waste and Water
RAE	Regulatory Authority for Energy
RAR	Regulatory Asset Register
RCC	Regional Coordination Center
RE	Renewable Energy
REPTP	Register of Eligible Participants in the Trading Platform
RES	Renewable Energy Sources
RMM	Reasonable Margin of Activity
RMR	Reasonable Maximum Retail Price
RP	Reference Price
RPRP	Regulated Producer Revenue Prices
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
SGU	Significant Grid Users
SMPRES	Special Market Price for Renewables
SOGL	System Operator Guideline
SOLR	Supplier of the Last Resort
SOR	System Operation Region
SoS	Security of Supply
SSL	Security of Supply Levy
STSP	Short-term standardized products
TAP	Trans Adriatic Pipeline
TAR NC	Regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures for gas
TE	Tariffed Energy
TMOFA	Temporary Mechanism of Optimal Forecast Accuracy
TNC	Trans Adriatic Pipeline Network Code
TSO	Transmission System Operator
TUoS	Transmission Use of System
TW	Terawatt
TWh	Terawatthours
TYNDP	Ten-year Network Development Plan
UGS	Underground Gas Storage
UOCC	Unit Charge for RES and HECHP Producers
USS	Universal Service Supplier
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, WASTE AND WATER

132, Piraeus str., 118 54 Athens, Greece

Tel.: +30 210 372 7400

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