Market Reform Plan for Greece

Preliminary for consultation only – Subject to Revision

Version 5, July 15, 2021

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1 Introduction

1.1 EU Regulation

Article 20 of the European Parliament and Council 2019 Regulation (EU) 2019/943 on the internal electricity market states: *"Member States that have identified resource adequacy difficulties are establishing and publishing an implementation plan with a timetable for the adoption of measures to eliminate all regulatory distortions or market deficiencies that have been identified, as part of the state aid process".* In addition, Article 21 of the same regulation states that *"when a Member State applies a capacity mechanism, it reviews it and ensures that no new contracts are concluded under this mechanism when both the assessment of resource adequacy at European level and the assessment of resource adequacy at the national level or, in the absence of a national resource adequacy assessment, the European-wide assessment of resource adequacy did not identify any difficulties in adequacy of resources, or where the implementation plan for Article 20, paragraph 3, did not receive a view from the Commission as referred to in Article 20, paragraph 5.* »

Article 20 of Regulation 2019/943 specifies the various topics to be considered by national authorities when they draw up their implementation plan. All of these themes are covered by this implementation plan.

1.2 Issues to address

"When *dealing with resource adequacy challenges, Member States take into account, among other things, the principles set out in Article 3, and consider:*

1. To remove regulatory distortions;
2. to remove tariff caps in accordance with Article 10;
3. to introduce a shortage pricing function for balancing energy, in accordance with the article 44, paragraph 3, regulation 2017/2195;
4. increase the interconnection capacity and capacity of the internal network to achieve, at the very least, their Interconnection Objectives under Article 4, d) 1), Regulation (EU) 2018/1999;
5. enable self-production, energy storage, active demand participation measures and energy efficiency by adopting measures to remove identified regulatory distortions;
6. Ensure that the contracting for balancing and ancillary services is economically efficient and market-based;
7. to remove regulated prices where Article 5 of the Directive (EU) 2019/944 requires it. »

1.3 Economic viability assessment

The present report includes elements of the economic viability assessment, pertaining to the current situation as observed during the six-months operation of the target model in Greece, and provides analysis for the following:

1. Financial analysis of revenues and comparison to costs based on statistical information and the functioning of the market reflecting the current market design.

2. Identification of threats and trends in the future regarding economic viability assessment of power generation resources in relation to demand and system reserves.

2 Table of Market Reform Actions and timeline

A	Actions for the Wholesale Markets	Responsible party	Completion deadline
A.1	**Distinction of Balancing Energy and Energy due to Re-dispatching**	**IPTO**	**1-Dec-2021 for flagging and 31-Mar-2022 for settlement**
	TSO’s proposal on the distinction of Balancing Energy and Energy due to re-dispatching	IPTO	19-Jul-2021
	RAE's decision on the high-level design (compensation of re-dispatching)	RAE	2-Sep-2021
	Submission to RAE of the main regulatory document amendments (Balancing Market Rulebook and Methodologies)	IPTO	30-Sep-2021
	Public consultation of the main regulatory document amendments	RAE	1-10-Oct-2021
	RAE’s decision on approval the main regulatory documents amendments	RAE	31-Oct-2021
	TSO IT systems modifications for re-dispatching volumes flagging only	IPTO	1-30-Nov-2021
	Go-live of re-dispatching volumes flagging	IPTO	1-Dec-2021
	TSO IT systems for settlement of re-dispatching volumes	IPTO	1-Dec-2021-31-Mar-2022
	Settlement of re-dispatching volumes	IPTO	31-Mar-2022
A.2	**Distinct portfolio-based reserves market establishment**	**IPTO**	**To be explored**
	Presentation of TSO’s proposal for the restructuring of the balancing market in view of joining the European Balancing Platforms	IPTO	30-Oct-2021
	Legislation amendment regarding co-optimization of energy and reserves	MINISTRY	
	Amendment of RAE's decision 369/2018 on the guidelines for Electricity Markets Rulebooks (co-optimization of energy and reserves, Balancing Market high-level design operation etc.)	RAE	
	Submission to RAE of the main regulatory document amendments (DAM-IDM Rulebook, Balancing Market Rulebook and relevant Methodologies)	HENEX-IPTO	
	Public consultation of the main regulatory document amendments	RAE	
	RAE’s decision on approval the main regulatory documents amendments	RAE	
	NEMO systems modifications (interface with Capacity Auction Platform etc.)	HENEX	
	TSO IT systems modifications and establishment of Capacity Auction Platform	IPTO	
	TSO Nomination Platform establishment	IPTO	
	Testing and dry-run period - Participants tests	HENEX-IPTO	
A	Actions for the Wholesale Markets (cont.)	Responsible party	Completion deadline

A.3	**Participation of Demand Response in the wholesale markets**	**IPTO**	**1-Feb-2022**
	Price elastic demand in the day-ahead and intraday markets		Implemented
	Law amendment to delegate competence to RAE for the electricity supply and demand aggregation activities (article 138, Law 4001/2011)	Ministry of Energy (MOE)	31-Oct-2021
	Ministry to issue a licensing regulation following RAE's opinion	MOE, RAE	31-Oct-2021
	Submission to RAE of the main regulatory document amendments (Balancing Market Rulebook and Demand Response Baseline Calculation Methodology)	IPTO	15-Sep-2021
	Public consultation of the main regulatory document amendments	RAE	30-Sep-2021
	RAE’s decision on approval the main regulatory documents amendments	RAE	7-Oct-2021
	TSO’s technical decision on prequalification tests for demand side participation in the balancing market	IPTO	30-Nov-2021
	TSO IT systems modifications (MMS for mFRR)	IPTO	31-Jan-2022
	Introduction of aFRR/demand response	IPTO	To be explored
	Go-live of demand response in balancing market	IPTO	1-Feb-2022
A.4	**Participation of storage in the wholesale markets**		**end-2022**
	Development of legislative storage framework (licensing, market participation, network access etc.)	MOE	31-Oct-2021
	Adjustment of DAM-IDM-FM Regulations for storage participation	HENEX	28-Feb-2022
	Adaptation of DAM-IDM-FM IT systems	HENEX	30-Sep-2022
	Adjustment of Balancing Market Regulation for storage participation	IPTO	31-Aug-2022
	Development of manuals and technical requirements of storage facilities and their connection to the grid	IPTO	31-May-2022
	Adaptation of the Balancing Market IT systems	IPTO	31-Dec-2022
A.5	**Participation of dispatchable RES units and RES portfolios as BSPs in the Balancing Market**	**IPTO**	**8-Mar-2022**
	Submission to RAE of the main regulatory documents amendments (Balancing Market Rulebook)	IPTO	30-Sep-2021
	Public consultation of the main regulatory documents amendments	RAE	15-Oct-2021
	RAE’s decision on approval the main regulatory documents amendments	RAE	22-Oct-2021
	TSO’s technical decision on prequalification tests	IPTO	15-Dec-2021
	TSO IT systems modifications (mFRR)	IPTO	28-Feb-2021
	Introduction of aFRR	IPTO-RAE	To be explored
	Go-live of dispatchable RES and RES portfolios in balancing market	IPTO	8-Mar-2022

A	Actions for the Wholesale Markets (cont.)	Responsible party	Completion deadline
A.6	**Launch of Complementary Regional Intraday Auctions (CRIDAs)**	**HENEX-IPTO**	**21-Sep-2021**
	IT tests	HENEX-IPTO	10-Sep-2021
	MPs tests	HENEX-IPTO	2-Jul-2021
	Acceptance tests	HENEX-IPTO	10-Sep-2021
	Submission to RAE of DAM-IDM Rulebook amendments (CRIDAs' products etc.)	HENEX	30-Jun-2021
	Public consultation of DAM-IDM Rulebook amendments	RAE	20-Jul-2021
	RAE's decision on DAM-IDM Rulebook amendments	RAE	29-Jul-2021
	Submission to RAE of regional costs related to CRIDAs (coordinator costs etc.) and sharing keys-Art. 80(4) CACM	HENEX-IPTO	30-Jun-2021
	RAE's decision on approval of regional costs related to CRIDAs and sharing keys (Government Gazette)	RAE-ARERA-AERS	28-Aug-2021
	Submission to RAE of all documents proving contractual readiness	HENEX-IPTO	13-Sep-2021
	Submission to RAE of all documents proving technical readiness	HENEX-IPTO	13-Sep-2021
	Recommendation by NEMO and TSO on the go-live date	HENEX-IPTO	13-Sep-2021
	RAE's decision on the go-live date of the Intraday Market coupled operation (CRIDA) (Government Gazette)	RAE	21-Sep-2021
A.7	**Participation of Traders in the Intraday market -Launch of Intraday PTR Auctions for non-EU bidding zone borders**	**IPTO**	**during 2022 (depending on agreement with non-EU TSOs, NRAs, NEMOS, SEECAO)**
	Letter to the Regulators of Albania, North Macedonia and Turkey to support the delivery of Intraday PTR Auctions and the splitting of costs	RAE	18-Jul-2021
	IPTO proposal for intraday PTR auctions for non-EU bidding zone borders	IPTO	31-Oct-2021
	Drafting of IPTO and non-EU TSOs agreement	IPTO-non-EU TSOs	depends on third parties
	IPTO and non-EU TSOs agreement signing	IPTO-non-EU TSOs	depends on third parties
	SEE CAO, IPTO and non-EU TSOs agreement signing	IPTO-non-EU TSOs-SEE CAO	depends on third parties
	Technical and operation adjustments by SEE CAO	SEE CAO	depends on third parties
	Technical and operation adjustments by IPTO (XBMS System, etc.)	IPTO	6 months after agreement of third parties
	Technical and operation adjustments by HENEX	HENEX	implemented
	Cost allocation acceptance by non-EU TSOs	IPTO-non-EU TSOs	depends on third parties

A	Actions for the Wholesale Markets (cont.)	Responsible party	Completion deadline
A.8	**Launch of Continuous Intraday Coupling (1st phase)**	**HENEX-IPTO**	**8-Mar-2022**
	Resolution on traded products and technical validations	HENEX-IPTO-RAE	7-Jul-2021
	Detailed Market Design completion (roles, interface etc.)	HENEX	16-Jul-2021
	Detailed Market Design completion (roles, interface etc.)	IPTO	16-Jul-2021
	Local Trading System Specifications	HENEX	16-Jul-2021
	Technical and operation adjustments by IPTO	IPTO	30-Sep-2021
	HENEX Decisions (Timeline Procedures for the Day-Ahead and Intra-Day Market and XBID validations) amendment	HENEX	30-Sep-2021
	Submission to RAE of DAM-IDM Rulebook amendments (XBID's products etc)	HENEX	30-Oct-2021
	Public consultation of DAM-IDM Rulebook amendments	RAE	1-15-Nov-2021
	RAE's decision on DAM-IDM Rulebook amendments	RAE	31-Jan-2022
	Bilateral, FiT and SiT IT Tests	HENEX-IPTO	21-Jan-2022
	Participants Tests – Trial period (Dry runs)	HENEX-IPTO	18-Feb-2022
	Submission to RAE of all documents proving contractual readiness	HENEX-IPTO	31-Jan-2022
	Submission to RAE of all documents proving technical readiness	HENEX-IPTO	25-Feb-2022
	Recommendation by NEMO and TSO on the go-live date	HENEX-IPTO	25-Feb-2022
	RAE's decision on the go-live date of the Intraday Market coupled operation (SIDC) (Government Gazette)	RAE	1-5-Mar-2022
	Launch of Continuous Intraday Coupling (2nd phase)	**HENEX-IPTO**	**31-Dec-2022**
	15 minutes products introduction (ETSS/EMCS amendments and submission to RAE of DAM and IDM Rulebook amendments, TSO actions for market schedules' transfer from the ETSS to the MMS (demanding MMS και MSS important amendments), IPTO's methodology and technical solution for the transformation of quantities and information (XBID MTU differs from ISP MTU))	HENEX-IPTO-RAE	31-Dec-2022
	TSO Nomination platform establishment instead of validation checks by HENEX (amendments to the IT systems, to the regulatory framework and to the BM operation)	IPTO-RAE	31-Dec-2022

A	Actions for the Wholesale Markets (cont.)	Responsible party	Completion deadline
A.9	**Resumption of the possibility of BSPs to submit Balancing Energy bids with negative prices**	**RAE**	**1-Dec-2021 (linked to action A.1)**
	Submission to RAE of Balancing Rulebook amendment following developments on action 1	IPTO	30-Sep-2021
	Public consultation of the Balancing Rulebook amendment	RAE	15-Oct-2021
	RAE's decision on the Balancing Rulebook amendment (Art. 118A) (Government Gazette)	RAE	30-Oct-2021
A.10	**Participation of RES units in the Electricity Markets having full balancing responsibilities**		**8-Mar-2022 (linked to XBID)**
	Amendment of Law 4414/2016	MOE	31-Oct-2021
A.11	**Activation of scarcity pricing mechanism**	**IPTO**	**To be explored**
A.12	**Exploration (pros/cons) portfolio-based bidding in DAM and IDM and nomination platforms**	**RAE**	**To be explored**
A.13	**Exploration of self-scheduling and central dispatch**	**RAE**	**To be explored**
A.14	**Participation in the EU balancing platforms (MARI/PICASSO)**	**IPTO**	**24-Jul-2024 (ultimate)**
	RAE's decision on TSOs' derogation request approval	RAE	2-Dec-2021
	Drafting of the basic principles of the new market model and recording of the most important modifications required	IPTO	
	Public consultation of the high-level new market model design	IPTO-RAE	
	RAE's decision on the guidelines for drafting the new Balancing Market Rulebook	RAE	
	Submission to RAE of the main regulatory documents amendments (Balancing Market Rulebook, HETS Crid Code, Methodologies and Technical Decisions)	IPTO	
	Public consultation of the main regulatory documents amendments	RAE	
	RAE's decision on approval the main regulatory documents amendments	RAE	
	Technical Specifications for new IT systems and procedures	IPTO	
	Tenders for new IT systems and procedures development and implementation of necessary changes in existing local systems	IPTO	
	New IT systems and procedures development and implementation of necessary changes in existing local systems	IPTO	
	Interoperability tests between TSO and MARI and PICASSO platforms	IPTO	

A	Actions for the Wholesale Markets (cont.)	Responsible party	Completion deadline
A.15	**70% target (margin available for cross-zonal trade)**	**IPTO**	**mid-2022 (conditional on agreement with non-EU countries)**
	Achievement of the minimum level of available cross-zonal capacity set by Article 16(8) of Regulation (EU) 2019/943 for GR-IT bidding zone border	IPTO	Compliant
	Achievement of the minimum level of available cross-zonal capacity set by Article 16(8) of Regulation (EU) 2019/943 for GR-BG bidding zone border	IPTO	Compliant, considering exchanges with third countries
	Derogation request according to Article 16(9) of Regulation (EU) 2019/943 submitted to RAE for GR-BG bidding zone border for 2021	IPTO	11-Feb-2021
	RAE's decision on granting the derogation to IPTO for GR-BG bidding zone border for 2021	RAE	22-Jul-2021
	Development and publication of the methodology and projects that shall provide a long-term solution to the issue that the derogation seeks to address (Art. 16(9) of Regulation (EU) 2019/943)	IPTO	Development of methodology 31/12/2022, approval depends on the respective NRAs
	IPTO in a joint effort with TSOs of Bulgaria and Romania and SELENE RSC defines a common methodology to include non-EU TSOs in the 70% criterion	IPTO	30-Sep-2021
	Completion of the second 400 kV line between BG – GR, Nea Santa – Maritsa projects that shall provide a long-term solution to the issue that the derogation seeks to address	IPTO	30-Jun-2022
A.16	**TSO-DSO Coordination Platform**	**IPTO-DEDDIE**	**24-Jul-2024**

B	Actions for Interconnections and grid reinforcement	Responsible party	Completion deadline
B.1	**Cross-border interconnection projects**		
	New interconnection Greece-Bulgaria	IPTO	1 line 400 kV in full operation end 2022
	Additional interconnection to Italy	IPTO	pre-feasibility studies
	Upgrade of the interconnection of Greece- North Macedonia	IPTO	feasibility study ; submitted to TYNDP
	Additional interconnection to Turkey	IPTO	pre-feasibility studies
	Additional interconnection to Albania	IPTO	very preliminary stage
	Southeast Electricity Network Coordination Centre (SEleNe CC)	IPTO	Established
B.2	**Cross-border interconnection projects**		
	Crete Phase I	IPTO	in operation today
	Crete Phase II	IPTO	mid 2023
	Skiathos	IPTO	end 2022
	Cyclades Phase D	IPTO	in 2024
	Dodecanese	IPTO	commissioning by 2028
B.3	**Reinforcement of the Transmission System**		
	Completion of the 400 kV backbone Peloponnese	IPTO	High priority
	Compensation and stability enhancement	IPTO	Q1 2022
	Rouf EHV S/S	IPTO	2021-2025
	Argyroupoli EHV S/S	IPTO	
	Second T.L. between EHV S/S Filippi – EHV S/S N. Santa	IPTO	
	Reinforcement projects (new T.L) Nevrokopi, Sidirokastro, Kassandra, Doliana, Agia	IPTO	
	Reinforcement projects (new or upgraded T.L) Kerkyra – Igoumenitsa, Halkidiki, Katerini, Ptolemaida – Kastoria – Florina, Mesochora – Arachtos, Trizinia	IPTO	
	Reinforcement projects (new submarine cable) South Ionian Islands Loop	IPTO	
	Reinforcement and renovation projects in existing S/Ss & EHV S/Ss	IPTO	

C	Actions for Retail Market Competition	Responsible party	Completion deadline
C.1	**Market Monitoring and Surveillance Mechanism**	**RAE**	**end 2021**
C.2	**Antitrust case - energy release by PPC**	**Ministry**	**end 2021**
C.3	**RES-PPA and support of energy intensive industry**	**Ministry**	**beginning of 2022**
	High-level design of the trading platform	Ministry	
	Notification for state aid (Guarantee Fund - compensation of RES costs for energy-intensive industries)	Ministry	
	Law amendment and regulations	Ministry-RAE	
	IT implementation of trading platform	HENEX - RAE	

D	Liquidity of Forward Market	Responsible party	Completion deadline
D.1	**Software extension and enhancement**	**HENEX**	**2021 - 2022**
D.2	**Customized products for hedging DAM and Balancing transactions**	**HENEX**	**end 2021**
D.3	**Antitrust case - energy release by PPC**	**Ministry**	**end 2021**
D.4	**RES-PPA and support of energy intensive industry**	**Ministry**	**beginning of 2022**

E	Investment support and capacity adequacy	Responsible party	Completion deadline
E.1	**Support of RES (communicated separately)**	**Ministry**	**2021 - 2022**
E.2	**Support of Storage (Resilience and Recovery Fund)**	**Ministry**	**end 2021 onwards**
E.3	**Interruptibility scheme - phased out in 3 months**	**Ministry**	**Phased out Sept. 2021**
E.4	**Strategic Reserve (auctions for lignite plants, Gas plants and Interruptible load)**	**Ministry**	**tentatively for 2021 to 2023**
E.5	**Capacity remuneration mechanism with reliability options and promotion of flexibility with broad participation of generation, demand response, storage and interconnections**	**Ministry**	**tentatively from end 2023 onwards**

F	Price limits and other restrictions - lifting	Responsible party	Completion deadline
F.1	**Lifting of 20% cap on physical contracts of vertically integrated suppliers**	**RAE**	**To be explored**
F.2	**Complex bids in DAM**	**RAE**	**To be explored**
F.3	**After continuous ID trading -9,999 EUR/MWH to +9,999 EUR/MWH**	**RAE**	**CRIDAs timing**
F.4	**Negative balancing energy offers allowed**	**RAE**	**1-Dec-21 (linked to A.1 and A.9)**
F.5	**Balancing energy offers up to +9,999 EUR/MWH after CRIDAs**	**RAE**	**21-Sep-2021**
F.6	**Balancing energy offers -99,999 EUR/MWH to +99,999 EUR/MWH after MARI/PICASSO**	**RAE**	**24-Jul-2024**

3 Overview of the electricity system in Greece

3.1 Overview of power capacity in Greece

3.1.1 Current situation

The Greek power generation system, excluding non-interconnected islands, operates in the second quarter of 2021 a fleet of 10500 MW dispatchable power plants, of which 2256 MW use lignite, 5212.5 MW use natural gas, and 3042 MW are hydropower plants with a reservoir. Among the gas plants, independent power producers (IPP) own and operate 2099 MW of CCGT plants, 351.5 MW are GTs owned by IPPs, 130 MW is an industrial CHP plant, and 2632 MW are CCGTs owned and operated by Public Power Corporation (PPC).

Around 1650 MW of lignite plants have retired in the period 2019-2021 for environmental reasons. The National Energy and Climate Plan (NECP), as officially endorsed at the beginning of 2020, phases out all existing lignite plants by 2023.

However, PPC has officially announced (by sending an official letter[1] to the IPTO and RAE on February 22, 2021) the retirement of the lignite fleet end of August 2021 due to economic losses. The announcement of PPC to withdraw all the lignite plants currently in operation (approximately 2256 MW) took the form of an official letter addressed to the IPTO and RAE. The letter announced the retirement as a firm (no-return) decision (it was not a request for mothballing the plants), asking for the deletion of the lignite plants from the registry of the IPTO and RAE. Both are the competent authorities to notify for such an announcement. The IPTO responded by an official letter stating that such retirement would seriously threaten the security of supply and would not accept such a retirement. Of course, the IPTO and any other authority cannot oblige PPC to keep the lignite plants in operation. The existing gas plants will reach their maximum technical lifetime after 2035. None of the existing gas plants has notified or announced an intention to retire.

Following a capacity adequacy calculation study by the IPTO, the capacity gap due to lignite plan retirement is a non-negligible threat to the security of supply until the beginning of 2023, when the new power plants under construction are will operate. Therefore, as there cannot be any market-based solution in such a short period, the Greek state proposed implementing a Strategic Reserve scheme.

3.1.2 Capacity additions and retirements

An IPP-owned CCGT of 825MW is under construction, having a completion time for the end of 2022 or the beginning of 2023. The gas plant owner is the Mytilineos Group.

A new lignite plant of 660MW (Ptolemaida V) owned by PPC is under construction, expected to start operation testing in the second half of 2022 and probably start commercial operation in 2023. A tentative plan of PPC is to convert the plant to burn natural gas in a CCGT technology for a total capacity of 1000 MW (without any use of lignite). The conversion is likely to become operational in 2025, the earliest. The Ptolemaida V lignite plant is thus likely to operate on lignite for only one or two years.

[1] According to the PPC letter, after August 30, 2021, all remaining lignite plants (of 2256 MW-net), namely Agios Dimitrios 1,2,3,4,5, Meliti and Megalopoli 3,4 should stop operating due to economic losses. The letter is an official declaration in conformance with the Codes and requests the removal of these plants from the IPTO's registry of dispatchable units.

There is no intention to include the Ptolemaida V lignite plant in the proposed Strategic Reserve scheme or the Capacity Remuneration Mechanism that the Greek state proposes implementing after the Strategic Reserve scheme towards the second half of 2023. From 2025 onwards, the upgraded CCGT Ptolemaida plant will burn gas and will be eligible in the Capacity Remuneration Mechanism.

Therefore, the total phase-out of lignite will complete in 2024, four years earlier than the year 2028, foreseen in the original NECP of Greece.

The hydropower (with reservoir) capacity additions are 29 MW in 2025 and 160MW in 2027, leading to 3360 MW hydropower plants in operation from 2028 onwards.

There are no other dispatchable units expected to commission in the future with sufficient confidence. According to the production license registry kept by RAE, four additional CCGT projects of a total capacity of 3280 MW are under consideration by independent power producers. Some of the potential investors applied for an environmental license and other permits. Still, there is no specific information about a final firm investment decision for these projects. None of them has, until now, have engaged in significant expenditures towards investment implementation.

Currently, 699 MW of hydropower plants are open-loop hydro pumping plants. They constitute the only storage electricity facilities in the Greek interconnected system. The NECP foresees the development of closed-loop hydro pumping projects of around 700MW, for which investment is still uncertain depending on investment support. In addition, the NECP plan foresees the deployment of battery storage of electricity for a variety of sizes and grid connections that would escalate up to 1400MW by 2030. Considering a possible support mechanism by the state, which is under consideration, developers have already manifested interest in many battery system investments. They have applied for over 10 GW of licensing to RAE. It is, however, worth mentioning that investment in new storage facilities is currently uncertain as heavily depending on investment support by the state.

As described in other sessions below, the market reform plan intends to fully integrate demand response and storage in all the stages of the wholesale markets, including in the balancing. Accordingly, demand response and storage will also be fully eligible in the Capacity remuneration mechanism to be proposed.

As mentioned, RAE has already granted about 10 GW of storage licenses. The market reform plan makes sure to grant full market participation and balancing involvement and responsibility to storage facilities, like any other plant. Therefore, there will be no obstacles or institutional barriers, and thus storage will freely participate in the markets. The regulation, under completion, addresses issues for the participation of storage units in the electricity market as independent participants or through representation also in the context of RES portfolios and aggregations; the licensing framework for their development; connection contract terms with the operators, including provisions for adapting their operation; as well as the inclusion of co-located storage stations with RES units (i.e. behind the meter) and installation along with efficient utilization of small scale storage units by energy consumers. Moreover, under the (NRRP) National Resilience and Recovery Plan’s funding, a specific investment support scheme is foreseen to allow through a tender process the development of new power storage facilities, as well as the support of the development of a large-scale hydro pumping station, with a total capacity of approximately 700 MW and up to 1400 MW for batteries of various sizes and connection types. The forthcoming inclusion of grid-connected storage facilities into the capacity mechanism is essential to broaden the flexibility resources to support. Rules are under consideration to avoid overlapping the capacity remuneration mechanism under preparation and the NRRP funding scheme regarding the investment support of new storage facilities.

3.1.3 Non-interconnected islands

The non-interconnected islands generate electricity in isolated systems using oil products. The ongoing program of connection of the islands with the interconnected mainland system has three main milestones towards the complete interconnection of all islands by 2030. The program foresees complete interconnection of Crete in 2023, after the partial connection implemented in 2021, the connection of all Cyclades around 2025, after the completion of the connection of part of Cyclades in recent years, and the connection of Dodecanese and Eastern/Northern Aegean islands before 2030. The interconnection of islands will increase the total load addressed by the mainland's generation system, as the oil-firing units of the islands will cease operation, allowing at the same time to increase deployment of renewables in the islands. The projections into the future consider the impacts of islands interconnection programs on the demand for electricity and the development of renewables.

3.1.4 Prospects for investment in renewables

The deployment of investment in variable renewables (RES) continues at an impressive pace pulled by the feed-in-premium support schemes, which will continue in the next few years before being terminated by 2025, the latest. The investment interest is vast, and the dynamism is equally manifesting for solar PV and wind onshore, with the former developing faster than the latter. There have been several announcements of large-scale merchant projects in solar PV. There is also interest to develop wind offshore, but the licensing conditions, infrastructure solutions and financial support schemes are not yet mature. The rest of RES technologies, such as run-of-river, biomass CHP and geothermal energy, develop slowly and remain low in total capacity.

At present, solar PV operating installations amount to above 3500MW, wind onshore has also exceeded 3500MW, whereas run-of-river is at 338MW and biomass at 133MW. A realistic prospect is to see 450MW new solar PV and 315MW new wind onshore commissions every year until 2030. Thus, by 2030, solar PV and wind onshore are likely to exceed 15GW of operating capacity. Wind offshore may range between 150-500MW by 2030, run-of-river may reach 500MW, solar thermal power generation and storage may develop (70-100MW), and biomass would not exceed 400MW by 2030. In this manner, the Greek power system will achieve a RES share (RES-E share) above 60 or 65% by 2030, in conformity with the targets.

The table below summarises the evolution of RES capacity as foreseen in the NECP of Greece.

Table 1: NECP projection for RES capacities

Power capacity (MW)	2020	2022	2025	2027	2030
Biomass and biogas	0.1	0.1	0.1	0.2	0.3
Hydro, incl. mixed pumping	3.4	3.7	3.8	3.9	3.9
Wind power	3.6	4.2	5.2	6.0	7.0
Solar PV	3.0	3.9	5.3	6.3	7.7
Solar thermal	0.0	0.0	0.1	0.1	0.1
Geothermal	0.0	0.0	0.0	0.0	0.1
TOTAL	10.1	11.9	14.6	16.4	19.0

3.2 Overview of power generation in Greece

3.2.1 Current situation

Influenced by the escalation of ETS carbon prices and the rapid deployment pace of RES, the structure of dispatchable (this term excludes variable renewables) power generation has shifted from lignite to gas domination. In 2020, gas-based generation covered 36% of total load and losses in Greece's interconnected system, lignite contributed by 11% only (mainly to maintain district heating supply in the North of Greece and occasionally to complement system services at scarcity times), while RES supplied 30% and hydro 6% of the total. Net imports covering 18% of total load and losses continued past trends and remain significant in Greece. A similar generation mix prevailed in the first quarter of 2021. Gas covered 30% of the total, and net imports got a 7% share, which is significantly below historical trends due to increasing costs in the broader area of the Balkans, driven by high ETS carbon prices and the phase-out of free allowances granting.

Although the lignite share in total power generation is low, the intended retirement of lignite plants from September 2021 onwards is a severe threat to the security of supply and the reliability of the power system. The IPTO performed detailed power system simulations assuming the retirement of the lignite plants in 2021 and found that until the operation of the new power plants, full commercial commissioning expected in 2023, a severe capacity adequacy gap arises. The study applied an hourly unit commitment simulation under various scenarios regarding demand and availability of dispatchable plants. The study calculated the loss of load probabilities using a stochastic convolution method. The results confirm that a significant amount of dispatchable power capacity will be missing in the power system in 2021-2023 if lignite-firing power plants retire prematurely. Therefore, the IPTO study proposed increasing power capacity per year to become available as strategic reserve power to re-establish the probability of loss-of-load to an acceptable level of reliability standards. Based on the IPTO analysis and after taking into consideration the system situation in the first semester of 2021, regarding demand, hydrological conditions and capacities available, achieving an acceptable level of reliability standards require contracting a strategic reserve for at least 1850 MW for 2021, 1775 MW for 2022 and 675 MW for 2023.

The NECP adopted the hypothesis that the EU ETS carbon prices will reach 30-32 EUR/tCO2 by 2030 after a linear escalation from 18 EUR/tCO2 in 2020. In reality, the average EU ETS carbon prices have exceeded 25 EUR/tCO2 in 2020 and have already increased to almost 40 EUR/tCO2 in the first quarter of 2021; at present, the ETS prices are of the order of 50 EUR/tCO2. The prospects are to see EU ETS prices further escalating in the future and reach levels above 50 EUR/tCO2 by 2030, following an increasing pace throughout. The fuel cost per unit of net electricity generation of the existing lignite plants ranges between 26 and 36.5 EUR/MWh (net electricity). At an ETS carbon price of 18 EUR/tCO2, as assumed by the NECP for 2020, the costs of purchasing allowances auctioned (EUAs) in auctions per unit of electricity produced ranges between 22 and 28 EUR/MWh. Therefore, the NECP's assumptions about EU ETS carbon prices could not predict the actual carbon prices.

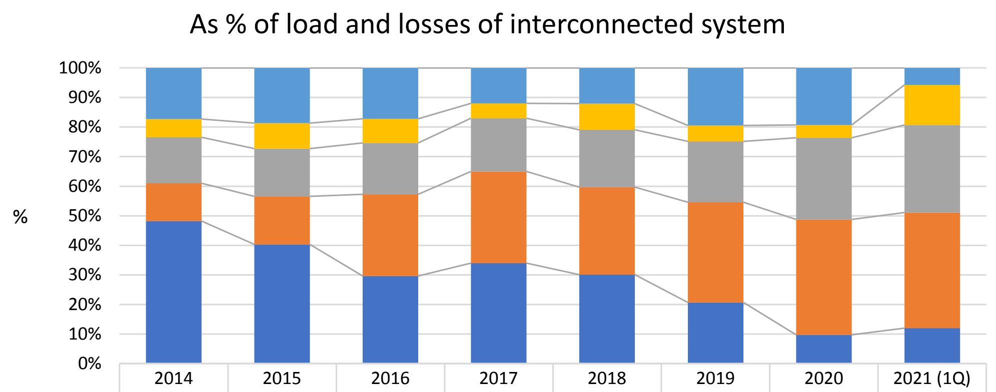
Under the currently persisting ETS carbon prices, above 40 EUR/tCO2 as prevailed on average in the first quarter of 2021 and further escalated recently up to 50 EUR/tCO2, the unit fuel costs of existing lignite plants are prohibitive for the day-ahead merit order. Under such carbon prices, total fuel cost per unit of electricity output would range between 90 to 105 EUR/ MWh (net electricity), or even above, outside the possible range of financial offers in the Day-Ahead wholesale market. Thus, the existing lignite plants are systematically outside the merit order and outside the plant scheduling. Furthermore, due to their inherent technological characteristics (warm-up time above 12 hours), there is no way for IPTO to activate them during the intra-day timeframe markets to provide balancing and reserves. If IPTO could call upon them beforehand and irrespectively of the day-ahead merit order, lignite plants could contribute to reserves. However, this is not possible under the current market rules.

Therefore, the expectation is that the existing lignite plants do not have any chance to be part of the merit order and the economic plant scheduling until their planned retirement by the end of 2023 (according to the NECP). Under pure market conditions, i.e. without out-of-the-market support, the existing lignite power plants cannot provide any balancing or reserve in the intra-day market and the real-time system operation. Thus, an alternative measure to engage those plants, such as the Strategic Reserve, is urgently required. For this purpose, it is justifiable to economically support the minimum fixed operation and maintenance costs that would allow the lignite plants to remain in a cold reserve regime.

The power supply structure, shown in Figure 1, results from the economic merit order based on the economic offers of the power plants and imports. The power capacities of dispatchable units have remained roughly unchanged during the indicated period; however, the renewables have deployed considerably. Therefore, the power supply mix change is mainly the outcome of the fuel costs, heavily influenced by the surge of ETS carbon prices mainly from 2018 onwards. The plant schedule, mirrored in the figure, Is not fully reflecting fuel costs as it also includes dispatching to meet system constraints. According to regulation, the economic offers of power plants had to be at least equal to marginal costs (mainly fuel costs) until the end of October 2020. Since Nov. 1 2020, based on RAE's RAE's decision 369/2018 (GG 1880/24.5.2018), there is no such a constraint, and thus the bids by power plants are free; however, they need to be specified and submitted separately by power generation unit.

The generation mix observed in 2020 and at the beginning of 2021 is a tremendous change compared to the mix a few years back. In 2014, when lignite covered almost 50% of total generation, operating in base-load, gas-based generation performed load following and had a significantly lower share in generation than currently. However, in the coming years, primarily renewables, and less gas, have replaced the decline of lignite in the generation mix. The average load factor (fraction of year operating in equivalent maximum net capacity) of gas-based generation has increased over time, above the mere 20% in 2014. Still, it has remained below 50% in 2020 and at the beginning of 2021. During the same period, the average load factor of lignite plants declined from above 75% in 2014 down to less than 20% in 2020.

Figure 1: Structure of power supply by fuel origin in the interconnected system of Greece (source TSO data)



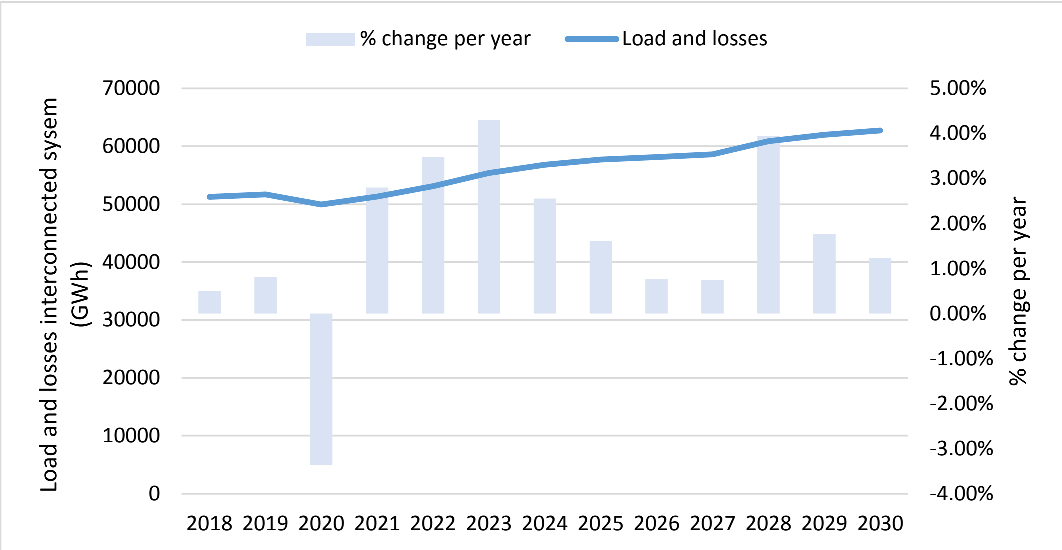
	2014	2015	2016	2017	2018	2019	2020	2021 (1Q)
NetImports	17%	19%	17%	12%	12%	19%	19%	7%
HYDRO	6%	9%	8%	5%	9%	5%	4%	16%
vRES	16%	16%	17%	18%	19%	21%	28%	34%
GAS	13%	16%	28%	31%	30%	34%	39%	45%
LIGNITE	48%	40%	30%	34%	30%	21%	10%	14%

3.2.2 Projections according to the NECP

The NECP foresees continuation and intensification of RES deployment towards reaching the objective of above 60% for RES-E by 2030. It is worth emphasizing that the forthcoming revision of the NECP is likely to revise the RES-E target upwards to comply with the upscaled European Union targets for 2030 within the Fit-for-55 policy framework.

The electricity demand projection into the future includes the electrification trend, which intensifies due to electricity penetration in the heating (heat pumps) and the mobility sectors (e.g. electric vehicles). The demand for electricity in the interconnected system will increase further as it will have to cover the load of the islands to be fully connected until 2030, as mentioned above. The upcoming milestones of islands interconnections are a significant driver of electricity demand growth, as shown in Figure 2.

Figure 2: Indicative projection of demand for electricity for the interconnected system, according to the NECP



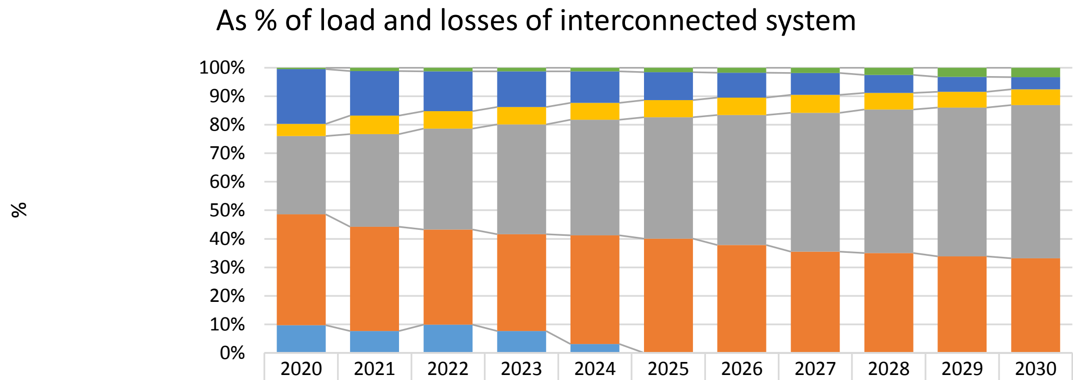
Source: Calculations based on NECP figures, to be revised by the forthcoming capacity adequacy study of IPTO

For the market reform plan purposes, it is necessary to emphasize the profound changes expected to occur in the power generation structure of Greece due to the deployment of renewables. The projection shown in this section uses the NECP figures and updated trends of investment pace in solar PV and wind.

The variability of renewables, beyond its stochastic nature, has a systematic pattern, particularly in systems with a high solar PV potential, as is the case of Greece. The solar radiation pattern induces considerable system requirements for fast ramping resources, which apply on multi-hour timescales, which expand beyond the conventional timeframe of ancillary services, which typically cover variations shorter than half an hour. The wind power resources also feature systematic patterns beyond the short-term stochasticity. Meteorological data make evident a two to four days systematic variability of wind.

Thus, the extensive development of variable RES requires considerable balancing resources beyond the conventional system reserves. Suppliers of such balancing resources are the gas plants, storage facilities, demand response, cross-border market, and system integration. All such resources are necessary because of their different potential and the different technical and economic features. By applying optimization methods, the NECP has projected the optimal mix of the balancing resources in the future to make possible the balancing of RES at least cost and at an acceptable reliability system performance.

Figure 3: Indicative projection of power generation mix in the interconnected system, according to the NECP



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Storage and DR extraction	1%	1%	1%	1%	1%	2%	2%	2%	3%	3%	3%
Net Imports	19%	16%	14%	13%	11%	10%	9%	8%	6%	5%	4%
HYDRO	4%	6%	6%	6%	6%	6%	6%	6%	6%	6%	5%
vRES	27%	33%	35%	38%	41%	43%	46%	49%	50%	52%	54%
GAS	39%	37%	33%	34%	38%	40%	38%	35%	35%	34%	33%
LIGNITE	10%	8%	10%	8%	3%	0%	0%	0%	0%	0%	0%

Source: Calculations based on NECP figures, to be revised by the forthcoming capacity adequacy study of IPTO

The projection shown in Figure 3 includes the impressive rise of variable RES, which attain 54% of power supply by 2030, a doubling from their share in 2020. Such a high share of non-dispatchable generation by 2030 has considerable implications for the system balancing and reserves due to the stochasticity and systematic variability features of variable RES. Gas-based generation plays a twofold role in the system under transition: to fill the energy generation gap left by the phase-out of lignite and primarily to balance the variable RES for both energy and capacity. The share of gas in the total electricity supply slightly increases until 2025. Afterwards, it declines steadily; the longer-term projections show a further significant decline of gas-based generation, after 2030, due to RES development. From 2024 onwards, the thermal resources of the system rely solely on gas and practically on the CCGT technology. The rest of the dispatchable resources are hydropower and storage. The plan finds that storage development is of strategic importance for the balancing and reserves and foresees significant investment in pumped storage and batteries, as mentioned above. However, storage performs its role as a load shifter, together with demand response, but not as a source of energy. The longer-term projections show a further reinforcement of the contribution of storage as a significant source of RES balancing.

The NECP foresees additional hydro pumping storage of 680 MW (Amphilochia) and 120 MW hybrid hydro storage systems and the development of batteries of various sizes and at different connection points up to 1450 MW in 2030. The volumes of storage have resulted from a least-cost system planning modelling. For the forthcoming upscaling of the RES-E objective in the NECP to be revised in 2021, the storage volumes are likely to increase to accommodate the balancing of additional renewables compared to the previous NECP.

The economic analysis performed in the NECP modelling and by an independent committee on storage suggests that it is unlikely for storage system investment to recover capital and operation costs from arbitraging hourly marginal prices of the wholesale markets, namely the Day-Ahead and Balancing Markets. This is because the increasing penetration of renewables decreases net load (i.e. gross load minus RES). At the same time, the increasing development of storage, needed for technical balancing of RES, implies lower wholesale market prices at net-load peak times and higher wholesale market prices at net-load peak net-load valley times. Therefore, the storage investment requiring recouping costs from the market price differences further reduces the price differences rendering cost recovery uncertain. It is thus unlikely to see large-scale storage investment, particularly large-scale hydro pumping, based on revenues only from wholesale markets.

The development of batteries strongly depends on the expected reduction of battery capital costs driven by worldwide learning-by-doing dynamics. Dropping battery costs are likely to happen, thus favouring the integration of batteries as behind-the-meter equipment in part of the new renewable energy investments. However, the system will also require large-sized batteries connected to the grid as merchant facilities providing balancing and system services. Currently, the economic analysis is pessimistic about wholesale market prices driving private investment in large-scale batteries. However, there could be a more positive prospect for large batteries within corporate RES-PPA supply portfolios, which are still immature in the business. The measures included promoting RES-PPA also intend to promote storage.

Therefore, investment support schemes have been included in the Recovery and Resilience Plan to trigger private investors to deploy storage facilities. The storage facilities will also participate in the capacity remuneration mechanism to be proposed. As mentioned above, the implementation details will not over-support or apply overlapping support to storage investment.

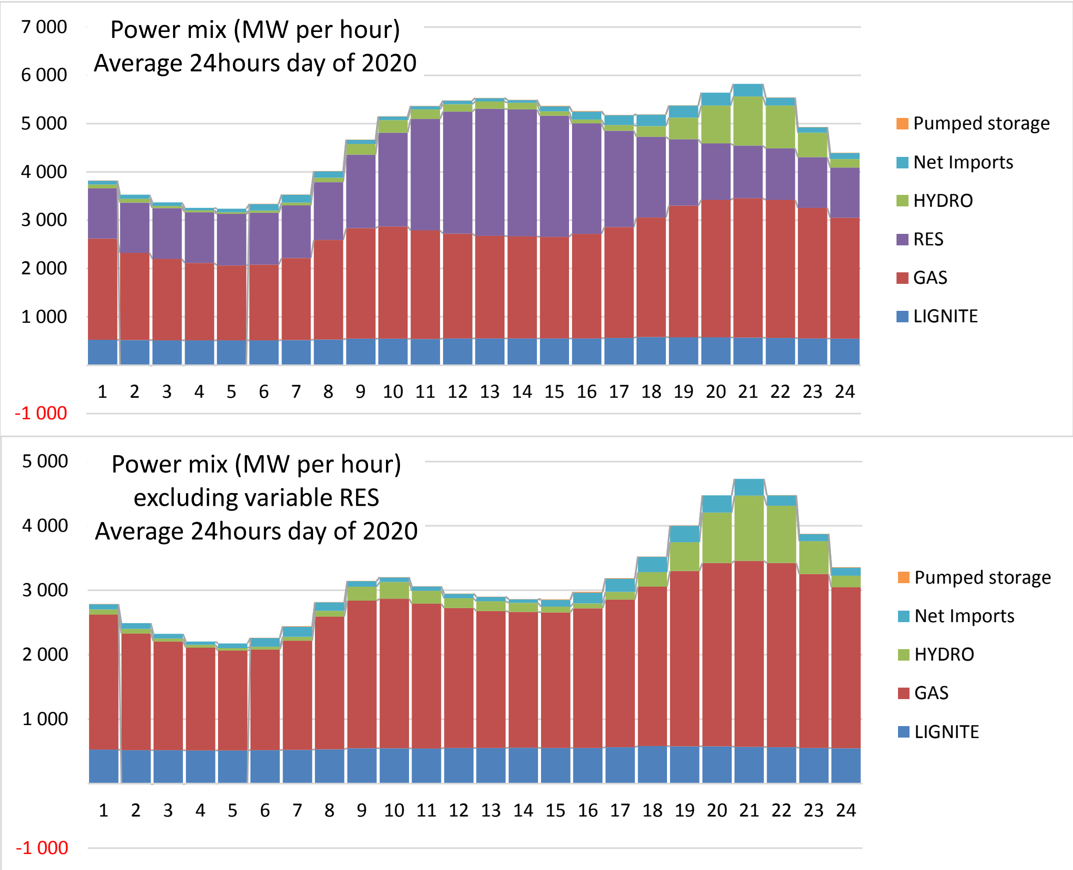
The projection included in the NECP shows that net imports are likely to decline in the current decade, discontinuing past trends. The profound changes of the transition towards low carbon power systems also occur in the broader South-East European region. The EU MS of the region has to pass through to prices, including for exports, the entire carbon emission cost amounts, which increase considerably driven by the surging ETS carbon prices. At the same time, both state-owned companies and private investors are reluctant to refurbish old lignite and coal plants, which are likely to be massively decommissioning during the current decade. Investment in new solid fuel projects are under revision and are postponed or cancelled.

On the other hand, a few new CCGT gas projects have emerged within the investment considerations. Finally, the entire South-East European region manifests revived interest in renewables investment due to their cost benefits. The countries that are not members of the EU are subject to the EU Acquis obligations regarding the opt-out of lignite/coal plants, the development of RES and the application of carbon pricing. Although the compliance with the EU Acquis is generally slow, the stringency of the EU regulations regarding emissions abatement discourages lignite/coal investment in non-Eu countries. Therefore, the prospect in the broader region is to see a growing lack of dispatchable energy, scarcity of balancing resources, and rising electricity prices, including for trade. At the same time, the completion of market coupling between the EU MS of the region and the possible increase in the potential of available interconnection capacities in the entire region would increase the possibilities of trade. However, reducing excess supply and increasing prices will offset the trade impacts of the augmented interconnection potential.

In this context, the projection of declining imports by the Greek plan is plausible. Detailed hourly simulations for the broader South-East European region, performed for the NECP, supported the rationale for seeing significant electricity exports from Greece to the rest of the region during the current decade. Exports are likely to occur mainly during excess RES production when low net-load occurs in Greece (net-load is load and losses minus variable RES). Low net-load and excess of RES imply over-generation threats and flexible units, such as the gas plants forced to shut down and startup frequently to perform fast ramping. Exports at such times avoid operation patterns that are costly for the operation and maintenance of gas plants, allowing collecting benefits from a smoother operation than otherwise, both for the gas plants and for RES that avoids curtailment. The rest of the region has a lower RES development than Greece and suffers less from over-generation threats.

Consequently, lack of energy drives an increase in exports from Greece during excess RES production. In contrast, when RES production is low in Greece, import flows from the rest of the region to Greece become economically attractive. According to the plan's projection, the yearly totals indicate that Greece is likely to remain a net importer but at significantly lower amounts than in the recent past.

Figure 4: Typical hourly pattern of power supply in Greece



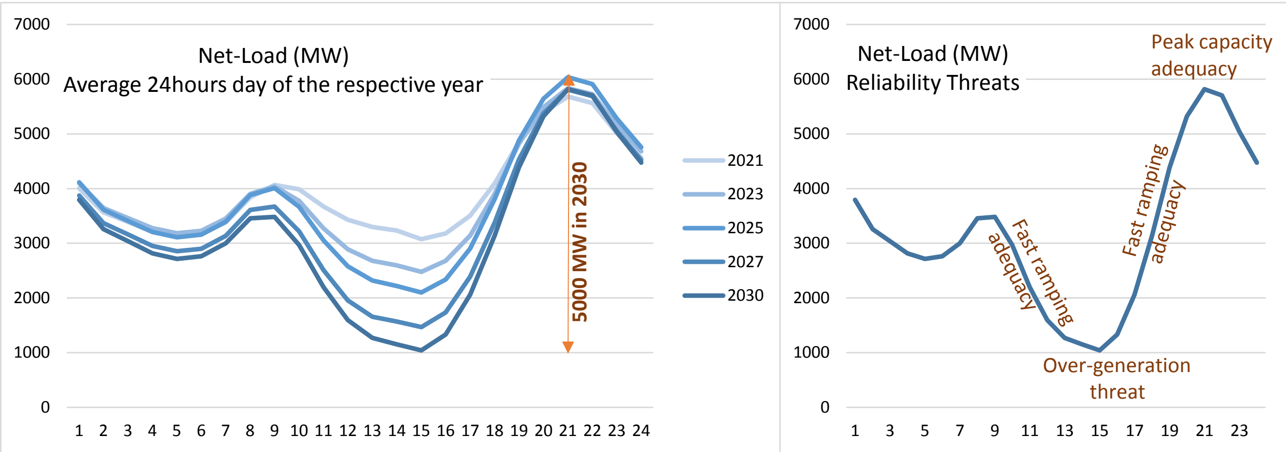
Source: Calculations based on NECP figures, to be revised by the forthcoming capacity adequacy study of IPTO

Figure 4 shows the average daily pattern of power supply per hour in 2020. The graph below does not include variable RES and thus shows power supply covers net-load. Averaging the days per season does not alter the illustrations of the figure. Also, the data for the first quarter of 2021 confirm the same pattern.

The hourly pattern clearly shows that the solar PV generation profile is dominant in the supply structure and has significant implications for electricity balancing. The net-load profile has already today the "duck" shape. A net-load valley occurs in the mid-day due to solar PV generation: in this period, over-generation threats are likely to occur in the future due to the further increase in solar. As demand increases and solar irradiation decreases in the evening, resources, including gas, hydro, imports and storage extraction, need to complement the low levels of RES generation to meet the peak load demand. During the entire afternoon, the balancing resources need to ramp up fast, afterwards, in the night. RES relies only on wind power while demand decreases; therefore, the balancing resources need to ramp down fast. In the morning, they need to ramp up fast until solar irradiation is high again.

The systematic hourly pattern of net-load and the balancing resources will feature accentuated variability in the future as solar PV increases, as expected. As illustrated in Figure 5, which shows that the “duck” shape of net-load gets more evident over time, the load valley in the mid-day deepens, and the distance from the evening peak load increases. By 2030, the dispatchable power resources will have to perform fast ramping of 5000 MW on average, every day, in the whole year, to meet the gap between the mid-day net-load minimum and the evening maximum net-load. Thus, there is more than a doubling of fast ramping capacity requirements in less than eight years.

Figure 5: Projection of Net-Load for an average day (based on NECP figures)



Source: Calculations based on NECP figures, to be revised by the forthcoming capacity adequacy study of IPTO

As shown in the right-hand-side graphic of Figure 5, the challenges for system reliability and security of supply are present every day in a system with high solar PV generation, as is the case in Greece. The traditional system reliability challenge has concerned peak capacity adequacy occurring sporadically in a year.

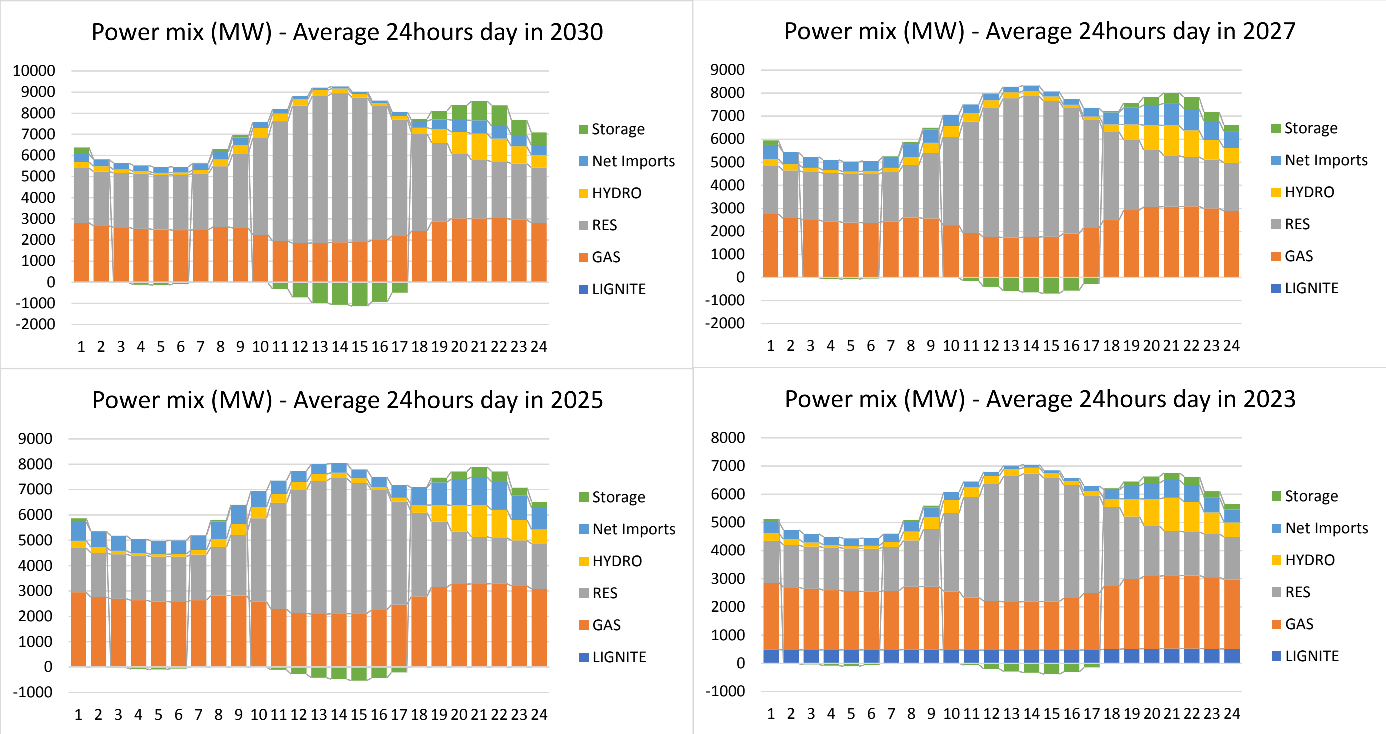
Towards high RES, the reliability challenges are much more frequent. In addition to meeting peak load, capacity adequacy concerns arise for over-generation threats; this occurs when net-load valleys cannot accommodate technical minimum power levels needing to close units and curtail RES. Severe concerns also arise regarding fast ramping adequacy, both up and down (as shown in the figure).

It is necessary to deploy storage, demand response and gas-based fast ramping spinning generation to accommodate the challenge of the “duck” shape of net-load as it evolves in the future driven by highly developing RES, notably solar PV. Moreover, as mentioned above, demand response and storage are eligible in the capacity remuneration mechanism to be proposed. Hence, they will participate in all stages of the wholesale markets and the balancing market.

There is also a beneficial contribution from imports exports when the neighbouring systems feature different net-load shapes that, thus, are complementary to Greece. Logically the south of Italy develops solar PV quickly, as Greece does, and uses similar balancing resources. There is limited complementarity between the two systems. On the other hand, the northern to Greece countries may develop solar PV at a slower pace. Thus net-load balancing complementarities arise that imports-exports may exploit to benefit both systems.

The simulations show export possibilities in mid-day and imports in the evening and morning. The resulting smoothing of the “duck” shaped net-load would be beneficial.

Figure 6: Indicative projections of the power supply mix according to the NECP figures



Source: Calculations based on NECP figures, to be revised by the forthcoming capacity adequacy study of IPTO

Figure 6 illustrates the least-cost hourly operation of resources to balance the growing generation by variable RES over time. By 2030, storage and demand response shift load from the mid-day valley to the evening peak load, while hydropower contributes to the shedding of peak load. Gas-based generation provides fast ramping and spinning reserves while complementing the energy of the variable RES. The simulation projections intermediate years display quite a similar pattern for the power resource structure, but at a lower intensity.

The pronounced variability patterns persist almost in the entire decade until 2030 and intensify beyond. The forecasted patterns emphasize the role of storage and other flexible resources. It is worth emphasizing that the gas-based generation shrinks over time while performing the system-related cyclical operations at increasing intensity. The pattern is challenging operational and economic performance (due to plant stressing that is costly for maintenance) of CCGTs. The difficulty is also due to the fuel consumption curve of the technology, with a very high-efficiency performance when operating at a high load factor but with significantly reduced efficiency when operating close to the technical minimum power level or when operating cyclically with frequent starts and stops. The simulations reveal that, as variable RES increases, the cyclical operation of CCGTs intensifies, their efficiency deteriorates, and the costs to recoup increase.

3.2.3 Implications for the market reform plan

The stressed daily operation of all balancing resources is evident already before 2030 in the NECP plan simulations. It worsens in scenarios with more RES (as in the forthcoming NECP revision to comply with the upscale FIT-to-55 targets). It is also stressful for the reliability threats, which occur frequently and are different from traditional systems, as already explained, regarding peak load, fast ramping and over-generation. The stress accentuates further after 2030 as variable RES continue to increase.

Consequently, coping with the challenges arising from the fast-evolving generation structure is the main aim of the market reform plan. Furthermore, the targets for very high RES and very low carbon emissions makes imperative the creation of suitable economic and technical conditions for the balancing resources to increase through private investment, remain in the market by recovering costs. In contrast, the mix of balancing resources of different natures are complementary to each other and at the same cost-effective.

The future power system will require the intense cyclical operation of gas plants while providing insufficient opportunities for price arbitraging for the load shifting resources (demand response and storage). Consequently, the revenues from the markets will not be enough to recover all costs of flexibility providing resources. As a remedy, the plan foresees a capacity remuneration mechanism to provide revenue assurance to all flexibility providing resources and help maintain them in the market.

3.3 Overview of interconnections and regional market coupling

3.3.1 Current situation

The synchronously interconnected neighbouring control area includes Albania, Bulgaria, Italy, North Macedonia and Turkey. The connection with Italy is DC and links to the southern zonal of Italy. Table 2 shows the interconnection figures updated at the end of 2020.

Table 2: Interconnection capacities of Greece

	Power capacity (MW)		Net Transfer Capacity (MW)		
			2020	2025	2030
Greece-Albania	1 line 400 KV	1095	250	400	400
	1 line 150 KV	108			
Greece-Bulgaria	1 line 400 KV	990	400 from GR 600 to GR	1400 from GR 1700 to GR	1400 from GR 1700 to GR
	1 line 400 KV in 2022	1440			
Greece-North Macedonia	2 lines 400 kV	1548	850 from GR 1100 to GR	850 from GR 1100 to GR	850 from GR 1100 to GR
Greece-Turkey	1 line 400 KV	1200	218 from GR 166 to GR	660 from GR 580 to GR	660 from GR 580 to GR
Greece-Italy	1 line 400 kV (HVDC)	500	500	500	500

Source: IPTO and ENTSOE

Greece achieves an interconnection level of 13.9%, already in 2020, against a target of 10% as provided for in Regulation (EU) 2018/1999. In fact, the sum of net transfer capacities of Greece was equal to 3.5 GW in 2020, which represents 13.9% of total operating capacities amounted to 25.2 GW in total.

The EU regulation also calls upon removing any barrier obstructing cross-border electricity flows and cross-border electricity market transactions. As the market coupling on a day-ahead basis is already in operation. As Greece plans to join the platforms for coupling intra-day trading and cross-border exchange of reserves, there are no such barriers to address. The plan precise the timing in other sections below.

Table 3 shows the yearly amounts of imports-exports occurred bilaterally in 2020, according to the ENTSOE data. The commercial origin of imports to Greece does not coincide with the origin of physical flows. The physical flows from Turkey are loop flows from Bulgaria, whereas those from North Macedonia are partly loop flows from Bulgaria. Partly wheeling flows take place from northern countries of the region.

In addition, the EU regulation requires MS action to address congestions in the cross-border flows due to infrastructure limitations and remove internal grid congestions. The current data and the simulations for the near future do not identify systematic congestions in cross-border flows. The average load factors (Table 3) of the cross-border connections, concerning the available net transfer capacity, have been in 2020 below 35%, except for the Greek-Italy link, which is a DC link, and the load factor has been close to 60%. With the new line linking with Bulgaria and the substantial increase in net available transfer capacities, as mentioned above, congestion is unlikely to occur. The simulations of the South-East regional market for the decade to come has shown price convergence in the southern part of the region, including Greece, for the large majority of the time slices.

Table 3: Imports - exports flows in 2020

GWh	Imports	Exports	Net Imports	*Average load factor relative to NTC*	Net Imports	Net Imports	Net Imports
Year	***2020***	***2020***	***2020***	***2020***	***2025***	***2027***	***2030***
Greece-Albania	610	397	213	*28%*	181	195	284
Greece-North Macedonia	2790	173	2617	*29%*	1626	1273	398
Greece-Bulgaria	1863	15	1848	*35%*	1499	1064	787
Greece-Turkey	1834	29	1805	*36%*	811	758	454
Greece-Italy	2572	316	2256	*59%*	1651	1293	876
Total	9669	930	8739	*36%*	5769	4582	2800

Source: ENTSOE for 2020 and projections, based on NECP assumptions, until 2030

Table 3 also shows a projection of cross-border electricity flows until 2030, based on the assumptions of the NECP. The projected figures result from the economically optimized operation of the interconnected systems of the South-East European region considering the NECPs of the EU MS and the plans submitted by non-EU countries in the context of the Energy Community procedures. The rising carbon prices entirely passed through to prices in the EU MS. The decline of lignite capacities in the entire region implies a reduced supply of inexpensive electricity. At the same time, the increase in the RES requires increasing balancing resources. The simulations assume unobstructed market coupling and a market-based determination of cross-border flows, both for meeting the demand for electricity and system reserve requirements. The projections support the conclusion that in the future net imports to Greece are likely to diminish. The interconnection capacities and the available net transfer capacities are not likely to obstruct the market-based flows, and the physical congestions are limited.

3.3.2 Implementation of the 70% target and timeline of coupling with non-EU borders

According to RAE Decision 1416/2020 (Government Gazette B'4954/10.11.2020), a derogation based on the provisions of Article 16(9) of Regulation (EU) 2019/943 has been granted to IPTO for the year 2020 on foreseeable grounds for maintaining operational security.

Given that as of 1st of January 2021, IPTO S.A. is still not able to comply with the binding target set in Article 16(8) of the Regulation 2019/943 without potential risk of operational security for the Greek grid for the year 2021, IPTO has requested for a derogation for the year 2021 per Article 16(9) of the Regulation 2019/943. The submitted document justifies the request based on the absence of consideration of flows of third countries in the capacity calculation and the margin available for cross-zonal trade, the insufficient potential for remedial actions to guarantee the 70% capacity criterion and insufficient IT tools for capacity calculation process embedding the 70% threshold, in line with the Regulation (EU) 2019/943.

Greece's net transfer capacities with Bulgaria increase to 850 MW from 2021[2] onwards and above 1650 MW from 2023 onwards. Thus, both would be above the threshold of 70% of thermal interconnection capacity, as currently required by the Regulation, provided that the detailed calculation involving non-EU TSOs is in place as planned. See Appendix A for further details regarding the application of the 70% rule.

The net available capacity with Italy is set at 500 MW, i.e. at 100% of the interconnection's capacity, as it is a DC link.

After 2023, the total available net transfer capacity of Greece will be at least 4750 MW, including the new line with Bulgaria expected to become operational by 2023; for a total installed capacity of 23000 MW as estimated for 2025, the interconnection level of Greece will exceed 20%, which is above the requirement of 15% for 2030 according to the Regulation.

According to Article 20(4) of Regulation (EU) 2015/1222, no later than six months after at least all South-East Europe Energy Community Contracting Parties participate in the single day-ahead coupling, the TSOs from at least Croatia, Romania, Bulgaria and Greece shall jointly submit a proposal to introduce a common capacity calculation methodology using the flow-based approach for the day-ahead and intraday market time-frame. Furthermore, the proposal shall specify an implementation date of the common capacity calculation methodology using the flow-based approach no longer than two years after the participation of all SEE Energy Community Contracting Parties in the single day-ahead coupling.

The day-ahead common capacity calculation methodology applying the coordinated net transmission capacity approach in the SEE CCR has just started to be implemented (01.07.2021) by the TSOs. However, further discussions on transitioning to a flow-based approach have not started yet.

3.3.3 Plan for new cross-border interconnections

The current IPTO's plan for the interconnections and accompanying market coupling initiatives, as briefly presented below, address the regulatory requirements to remove any obstacles to a free electricity market in the region for energy and reserves. The additional interconnection projects under consideration are as follows:

<u>Additional interconnection to Italy</u>

In November 2020, IPTO and the Italian TSO, TERNA, formed a joint working group to prepare studies to strengthen the interconnection of the two electrical systems. The collaboration regards a new submarine interconnection between the systems of Greece and Italy, while at the same time the possibility of maximum use of the existing infrastructure of the DC interconnection between Greece and Italy, in operation since 2002. According to the current estimates, the need for reinforcement ranges between 500 - 1000 MW.

<u>Upgrade of the interconnection of Greece- North Macedonia</u>

[2] After a proposal by IPTO, RAE submitted in 2020 a request for exemption from the 70% obligation for the NTC of the link Greece-Bulgaria and the exemption has been approved for one year. At present, i.e. after the first quarter of 2021, the NTC of the Greece-Bulgaria link is at least equal to 70% of the interconnection capacity.

The project, already submitted to the Ten-Year Network Development Plan (TYNDP) 2020, is under consideration by IPTO and the TSO of North Macedonia, MEPSO. A joint IPTO and MEPSO working group will soon launch a feasibility study for the interconnection investment.

Additional interconnection to Turkey:

A joint working group involving IPTO, the TSOs of Bulgaria (ESO_EAD) and Turkey (TEIAS) is assessing alternative scenarios for the development of new interconnections between the European and the Turkish systems. The aim is to increase transmission capacity at the Greece-Turkey and Bulgaria-Turkey borders. Already completed joint studies have shown that there is scope for interconnection enhancement between the European and the Turkish system. Benefits would stem from the strengthening of those systems at their shared borders. A meeting held in Izmir between IPTO, ESO-EAD and TEIAS decided to submit a new project entitled “East Balkan Corridor” to the TYNDP of ENTSO-E. Projects for a 400 kV interconnection Greece - Turkey and 400 kV interconnection Bulgaria – Turkey are part of the submissions for “projects under consideration” within the TYNDP 2020. The evaluation results of TYNDP 2020 confirmed the need to increase the transmission capacity between these countries.

Additional interconnection to Albania:

In April 2020, IPTO started collaborating with the TSO of Albania (OST) regarding the possibility of implementing a new interconnection between Greece and Albania. Discussions are at a preliminary stage and focus on assessing the technical, financial and other parameters for designing a new interconnecting line at the 400 kV level between the south transmission system of Albania and a suitable EHV S/S in Greece.

Table 4: Summary of cross-border interconnection planning

Interconnection	Planning
New interconnection Greece-Bulgaria	1 line 400 kV in full operation end 2022
Additional interconnection to Italy	in the stage of pre-feasibility studies, no decisions yet
Upgrade of the interconnection of Greece- North Macedonia	a feasibility study is ongoing, no decisions yet; submitted to the Ten-Year Network Development Plan (TYNDP) 2020 as a project under consideration by IPTO and MEPSO
Additional interconnection to Turkey	in the stage of pre-feasibility studies, no decisions yet
Additional interconnection to Albania	discussions in a very preliminary stage

3.3.4 Plan for new interconnections of islands

Regarding the interconnection of Greek islands to the interconnected system of the mainland, the following projects are under development intending to achieve complete interconnection before 2030:

Interconnection of Crete – Phase II:

It comprises the interconnection between Crete and Attica via a bipolar DC link (2 x 500 MW). It consists of two submarine cables of 335 Km length and additional underground (at both sides) and overhead lines (in Crete) and also two AC/DC converter stations in Attica (Koumoundouros EHV S/S) and Crete (Damasta S/S). The project is in progress and is expected to be commissioned in the first semester of 2023.

Interconnection of Skiathos:

The project involves the interconnection at 150 kV of Skiathos to the system of Evia (Mantoudi S/S). It comprises the reinforcement of part of the existing 150 kV OHL Mantoudi - Edipsos and the connection of the one circuit to Skiathos, with one submarine and underground cable circuit of 200 MVA transfer capacity, with a 28,4 km length. It also includes the construction of one GIS substation in Skiathos. It is expected to be commissioned in 2022.

Interconnection of West and South Cyclades (Cyclades Phase D):

This project involves the interconnection of Thira, Folegandros, Milos and Serifos in a closed-loop to the interconnected System of Northern Cyclades via Naxos S/S and the HETS to Lavrio EHV S/S. The interconnection consists of five underground and submarine cable circuits of around 350 km and four GIS substations on the islands. Commissioning is expected in 2024.

Interconnection of Dodecanese: The main part of the project involves a bipolar DC link (2 x 450 MW) that will connect EHV S/S Korinthos with the island of Kos. The link consists of two AC/DC converter stations in Korinthos and Kos and two submarine cables, with a length of 380 km and additional underground lines (at both sides). Rhodes shall connect to Kos with three 150 kV AC submarine cables, each of average length of 100 km and 200 capability of MVA. The interconnection will go from Rhodes to Karpathos island, initially with one 150 kV AC submarine cable with a length of 88 km and 200 MVA capability. The project includes the construction of two GIS substations in Kos and Karpathos. Commissioning is expected in 2028.

Interconnection of Northeast Aegean Islands: It involves the interconnection of Lemnos to the HETS, with Nea Santa EHV S/S and via Lesvos and Skyros to the System of Evia (Aliveri EHV S/S). It includes radial interconnections Lesvos - Chios, Chios - Samos and Samos - Kos. The project also foresees the construction of five GIS substations in Lemnos, Lesvos, Skyros, Chios and Samos, and the installation of an SVC or STATCOM in Lesvos S/S. All islands connections use 150 kV AC submarine cables of various average lengths and 250 MVA capability. Commissioning is expected in 2029.

Table 5: Summary of interconnection planning for islands

Interconnection	Planning
Crete Phase I	in operation today
Crete Phase II	mid-2023
Skiathos	end 2022
Cyclades Phase D	in 2024
Dodecanese	commissioning by 2028
North-East Aegean islands	commissioning in 2029

3.3.5 Plan for reinforcement of the transmission system

Finally, the following upgrade, reinforcement and expansion of the transmission system are within the implementation plan in the framework of the current decade:

- Completion of the 400 kV backbone to Peloponnese
- Projects for compensation, storage and stability enhancement & control of the transmission system

- Rouf EHV S/S (new)
- Argyroupoli EHV S/S (new)
- Reinforcement of the 400 kV System in the region of Eastern Macedonia and Thrace (Second T.L. between EHV S/S Filippi – EHV S/S N. Santa)
- Reinforcement projects (new T.L) to ensure the security of supply of radially connected S/S (Nevrokopi, Sidirokastro, Kassandra, Doliana, Agia)
- System reinforcement projects (upgrade and/or new T.L) in the area of Ioannina, Kerkyra – Igoumenitsa, Halkidiki, Katerini, Ptolemaida – Kastoria – Florina, Mesochora – Arachtos, Trizinia
- Reinforcement of the South Ionian Islands Loop (upgrade of submarine cable connections)
- Reinforcement and renovation projects in existing S/Ss & EHV S/Ss

The expansion of the 400 kV backbone to Peloponnese is almost finished (98% completion), with only two pillars of the overhead line remaining for installation. However, following reactions from a local Monastery, an interim measures Court ordered works suspension. Following this decision, IPTO is investigating a technically feasible alternative route to the original licensed one. The total estimated time required for the implementation of the alternative is approximately 20 months. In any case, IPTO will seek to overturn the aforementioned interim measures decision during the lawsuit trial. The estimated time for the issue of the relevant judgement is 8 – 12 months.

The transmission system constraints that affect the balancing market and imply re-dispatching are:

a) The congestion in Peloponnese because of a delay in the commissioning of the Megalopolis - HETS transmission line of 400kV. The Peloponnese transmission constraints have implied a need for significant downward re-dispatching of gas plants within the ISP. Also, due to an N-1 reliability rule applying to the Peloponnese part of the System, one of the Megalopolis lignite plants may receive a must-run instruction by the IPTO when congestion occurs in Peloponnese.
b) The avoidance of persisting System over-voltage events, which must not exceed the limits set by Regulation (EU) 2017/1485. The over-voltage avoidance constraints occur in the North of Greece when the load is low. Therefore, it is imperative to run a few of the lignite plants by calling upon general restrictions within the ISP. The must-run scheduling is also necessary because, due to high costs, the lignite plants do not succeed in the DAM merit order when the load is low. Moreover, the lignite plant scheduling as a must-run requires long warm-up times due to the technical features of lignite plants.

Both transmission constraint categories have induced considerable re-dispatching changes that, in consequence, imply large amounts of balancing energy requirements. Hence, the system-drive re-dispatching entails high energy balancing costs. As flagging mechanisms for system-driven re-dispatching causes do not yet apply, the re-dispatching influences the balancing energy market prices considerably.

In particular, regarding the Peloponnese transmission constraint related to Megalopolis, RAE has considered, as an interim measure, a price limit to downward deviations. The measure applies until the completion of the transmission reinforcement work that will lift the congestion. RAE diagnosed that few power production plants situated in Peloponnese have de facto a market power in the implied re-dispatching requirements. Thus, the measure adopted by RAE has a market power mitigation purpose, to avoid un-justified costs for consumers. The provisional measure refers to the suspension of the possibility of Balancing Service Providers to submit Balancing Energy bids with negative prices until the commissioning of the reinforcement line in Peloponnese.

Moreover, the TSO takes the obligation to implement Article 13 of Regulation 943/2019 concerning flagging of re-dispatching volumes due to system constraints to apply a distinct remuneration from energy balancing volumes. In this manner, the system-driven re-dispatching would not "pollute" the energy balancing market price. At the same time, both the provisional measure and the permanent flagging remedy addresses concerns about the eventual abuse of market power when system constraints occur. Should there be extended delays in the commissioning of the Megalopolis-HETS transmission line of 400 kV, RAE will re-consider the timing of lifting this temporary measure.

Regarding the over-voltage avoidance in Northern Greece, which occurs when the load is low, the inclusion of must-run lignite plants constraints is a last-resort measure. Prior to the must-run order, the IPTO has exhausted all other possibilities (ultra-high voltage circuits and induction systems) allowed for by the existing network system infrastructure in the Northern Greece area. As a permanent remedy to fixing the transmission constraints arising from lignite phase-out and the increase of RES, the IPTO has already proposed a comprehensive investment plan to implement in 2021 with a possible extension in the first quarter of 2022. The plan foresees installing a series of compensation equipment, notably coils, which upon implementation will allow for removing the over-voltage threats and thus avoid any must-run dispatching of lignite plans. The time horizon for a complete problem fix is the first quarter of 2022.

4 Overview of retail market competition

4.1 Structure of demand by sector

The energy-intensive industry, connected to high voltage, has a 17% share in total demand for electricity, which is small compared to the rest of the EU. On the other hand, small consumers, residential, services, and small industries connected to low voltage consume around 60% of total electricity. The rest of consumers, 23% of the total, are medium to small size consumers and are connected to medium voltage. Therefore, the retail market segments include a small part of a few large-scale industrial consumers and a much larger part of small and dispersed consumers.

Table 6: Electricity consumption by customer and voltage categories

	2020	2019	2016	shares in 2019
Households (Low Voltage)	15724	15633	15048	33%
Services and Industry Low Voltage	11839	12843	12577	27%
Services and Industry Medium Voltage	10052	10586	10121	23%
Industry (High Voltage)	7291	7906	8177	17%
Total	44906	46968	45923	100%

Source: RAE, Report in 2020

4.2 Structure of supply in the retail market

In 2020, 26 suppliers (retailers) were active in the retail market of Greece. In the last ten years, the prices for all electricity consumers are free and are not regulated. Guidelines issued by RAE in 2011 regulate that consumer tariffs must be transparent, without cross-subsidies and reflective of consumer category characteristics. Particular guidelines apply to industrial consumer tariffs aiming at ensuring that prices derive from negotiations. All suppliers, including PPC and independent suppliers (other than PPC), must publish tariff conditions. A tariff monitoring and supervision system operate by RAE for consumer protection. The system informs about prices offered by suppliers. It collects information on market shares, revenues and costs per supplier, evaluates margins and thus monitor both economic viability and mark-up pricing.

Table 7: Indicative market shares of suppliers in the retail market in 2020

	PPC	Suppliers with IPP	Suppliers without IPP	Total
Households (Low Voltage)	79%	12%	10%	100%
Services and Industry Low Voltage	66%	18%	16%	100%
Services and Industry Medium Voltage	39%	37%	24%	100%
Industry (High Voltage)	96%	4%	0%	100%
Total	70%	17%	13%	100%
Total excluding Industry (High Voltage)	64%	20%	16%	100%

Source: RAE, Report in 2020

As shown in Table 7, PPC has an almost 100% market share in high voltage industrial consumers. Historically, the dominance was due to the market structure during the early stages of electricity market liberalisation. Suppliers (i.e. retailers) without ownership of electricity generation (without IPP activity) were purchasing energy from the mandatory poll, with average market marginal prices being bove industrial tariffs systematically. On the other hand, suppliers with ownership of electricity generation (with IPP activity) could not compete in the industrial market segment because the IPPs could only invest in gas plants with levelized costs higher than industrial tariffs.

However, the considerable rise in lignite generation costs currently makes the lignite-based industrial electricity supply non-affordable. According to information in the press, the bilateral contracts of PPC with energy-intensive industries are in a new negotiation process that aims at contract terminations in early 2023.

Implementing the RES-PPA measure will allow all retailers to have access to a low levelized cost of energy in their portfolio assets, which will enhance competition. The measure, enhanced with additional support schemes, will also apply to high voltage consumers. The RES-PPA measure combined with the measures facilitating access to RES by energy-intensive industry (as detailed in another section) will imply that from 2023 onwards, it is likely to see a drastic reduction of PPC's share in the supply of high voltage customers. The RES-PPA measures, the support schemes that facilitate investment in storage facilities and the measures allowing for the participation of storage assets in the markets aim at facilitating RES-based portfolios to meet consumer demand profiles. The ambition is to see green bilateral contracts to supply energy-intensive industries in a time horizon of a few years. At the same time, the measure will boost merchant RES investment. Given that RES investment and the forthcoming RES-based supply portfolios have a wide market dispersion, the expectation is to see a drastic reduction of market concentration in the supply of high voltage industry in short to medium term.

The PPC's share in the market segment of households is relatively higher than in the services sector, as shown in Table 7. The competition between retailers is booming in Greece, but still, considerable inertia persists in consumers' market perception, particularly the households with low electricity consumption. The emergence of dynamic retail marketers is relatively young, but modern multi-product service offerings are flourishing. In this context, the application of the target model has not obstructed the dynamism of retail market competition. Both categories of suppliers, with and without IPP activity, succeeded in conquering market shares in the retail market, albeit in market segments other than for the high voltage industry. Currently, independent suppliers hold 36% of the retail market, without the high voltage industry.

The degree of supplier switching by customers is significant and dynamic. For example, in 2020, customers switching suppliers represented 7.8% of all customers connected to low and medium voltage. The trend is significantly increasing, as shown in Table 8.

Table 8: Historical data on consumers switching suppliers

Year	Number of customers switching supplier as % of total	Customers switching supplier as % of total electricity consumption
2020	7.8	8.12
2019	8.5	2.22
2018	4.51	3.96
2017	2.81	1.91
2016	1.58	2.22
2015	0.44	1.03
2014	0.19	0.48

The increase in retail market competition in the coming years depends on the expected restructuring of the power generation mix. It undergoes dramatic changes due to the high costs of lignite and the deployment of renewables. Consequently, the formation of dominant generation and supply portfolios are not possible anymore. The ensuing re-position of market players is hard to predict, while competition to form RES-based portfolios will be fierce. Such economic fundamentals are powerful driving forces to the restructuring of the retail market competition. Such market-based drivers are likely to prove powerful enough to achieve low market concentration in the coming years.

Table 9: Shares in power generation (interconnected system) versus shares in the retail market

	2020	2020 data	2021 (Jan. to May) data	2025 projection	2030 projection	shares in retail in 2020-21	
GWh		shares in generation					
PPC	15850	33%	38%	31%	25%	70%	(short)
IPP	10338	21%	22%	22%	17%	17%	(balanced)
v-RES	13578	28%	33%	43%	55%		
Net Imports	8832	18%	8%	3%	3%		
TOTAL	48598	100%	100%	100%	100%		

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Table 9 illustrates that the incumbent (i.e. PPC) has a small share in total power generation, much smaller than PPC's share in the retail market. The lack of competitiveness of lignite-based generation as a basis for bilateral contracts with customers weakens PPC's strength in the retail market. At the same time, the emerging possibility of forming portfolios with RES to supply customers bilaterally evenly spreads across the competitors, and PPC cannot dominate this future market. As The increase in retail market competition in the coming years depends on the expected restructuring of the power generation mix. It undergoes dramatic changes due to the high costs of lignite and the deployment of renewables. Consequently, the formation of dominant generation and supply portfolios are not possible anymore. The ensuing re-position of market players is hard to predict, while competition to form RES-based portfolios will be fierce. Such economic fundamentals are powerful driving forces to the restructuring of the retail market competition. Such market-based drivers are likely to prove powerful enough to achieve low market concentration in the coming years.

Table 9 further shows, the projections (following the NECP) forecast a slightly decreasing share of PPC in total generation from dispatchable power units. Therefore, it is logical to expect a trend towards a decreasing share of PPC in the retail market, seeing a smaller gap between generation and retail market shares. The independent retailers with ownership of dispatchable generation (depicted as IPP in The increase in retail market competition in the coming years depends on the expected restructuring of the power generation mix. It undergoes dramatic changes due to the high costs of lignite and the deployment of renewables. Consequently, the formation of dominant generation and supply portfolios are not possible anymore. The ensuing re-position of market players is hard to predict, while competition to form RES-based portfolios will be fierce. Such economic fundamentals are powerful driving forces to the restructuring of the retail market competition. Such market-based drivers are likely to prove powerful enough to achieve low market concentration in the coming years.

Table 9) have a slightly higher generation than retail market shares and thus have a somewhat balanced portfolio. As they will also expand in the market for RES-based bilateral contracting, they will have the opportunity to increase their market share, given that a combination of RES and efficient CCGT is quite competitive in the short-medium term to form bilateral contracts for customers. Consequently, the current underlying economic trends suggest that the concentration degree in the retail market is likely to decrease until 2030 by market forces.

4.3 Social tariff and universal service

A social tariff scheme applies to protect vulnerable consumers from energy poverty. The eligible customers meet income and social criteria specified by the law. Such customers receive a discount specified by the regulation. There are no fixed or regulated prices of electricity within the social tariff scheme. It is only a discount that applies to commercial electricity tariffs. The eligible customers must meet several fiscal and social criteria defined to select only households below the poverty thresholds. Fiscal authorities verify the fulfilment of the criteria. An upper bound applies to the energy consumed by households that are eligible for the social tariff discount. In 2019, the social tariff supported approximately 9% of household customers, consuming 1.8 GWh of electricity. A special levy, part of Public Service Obligations, applied to the rest of the consumers serves to recover the discount granted through the social tariff.

A Universal Service scheme introduced a decade ago acts as a last resort supply measure to provide electricity to consumers shunned by suppliers. The last resort scheme applies to households and small commercial customers (connected to low voltage and up to 25 kV network). The last resort scheme does not offer any discount on the price of electricity; in contrast, consumers covered by the last resort supply scheme pay more than the market price. The scheme covers for a short period customers abandoned by their supplier. The selection of suppliers to provide this service is an outcome of a tendering procedure. The regulation specifies that the tariffs within the scheme shall be higher than market-based tariffs. The customers under the Universal Service regime represented 0.8% of total consumption in 2020.

4.4 Measures for retail market competition

The opening of the retail market to competition has been a long process. Twelve years ago, PPC was holding almost 100% of the retail market. The State adopted a series of regulatory measures to facilitate market penetration of independent suppliers, among which an energy release program called NOME terminated a few years ago. The energy release aimed to provide independent suppliers with access to inexpensive lignite-based power generation, exclusively held by PPC. Nowadays, lignite-based generation is more expensive than other resources due to carbon prices, and lignite plants will be shortly phase-out. As a result, PPC has already today lost the competitive advantage related to lignite.

Therefore, there is no scope to continue the energy release program or other asymmetric regulation measures to diminish retail market concentration. As renewables increase considerably while carbon prices rise, the retail market competition will increasingly depend on access to renewables and balancing energy and reserves. The regulatory policy aiming to establish a level-playing field in the retail market will have to focus on these two segments and facilitate complete openness in the wholesale and balancing markets.

However, maintaining wholesale and balancing markets liquid and affordable is essential to sustain further development in retail market competition.

The gas plants owned and operated by suppliers with IPP activity have a total annual electricity production that slightly exceeds the electricity volumes supplied in the retail market. However, as the electricity generation cost structure depends on gas costs exclusively, they need to form portfolios that combine owned production and energy purchased from the wholesale market to hedge against price risks and be competitive in their offerings in the retail market. On the other hand, the competitiveness of suppliers without IPP activity is entirely dependent on the costs of the wholesale markets and the availability of energy (liquidity). In parallel, PPC's position is short, and its supply portfolio requires considerable energy purchasing from the wholesale markets.

According to all energy laws so far and the most recent law 4425/2016, all market participants are free to enter into bilateral contracts, freely or through the HEnEx financial energy (derivatives) market (with an option for physical delivery) not) or over the counter. No restrictions apply whatsoever. Volumes related to contracts with physical delivery are free to handle as nominations and declared in the Day-Ahead Market.

Provisionally, an upper limit (20% for 2021) applies to vertically integrated suppliers on the energy quantities included in the validated Physical Offtake Nominations and correspond to energy quantities of transactions on Energy Financial Instruments.

Bilateral contracts between suppliers and generators belonging to different entities have not been observed in the Greek market until now. Despite the absence of restrictions, parties seem not to have mutual economic interests to conclude such business-to-business bilateral contracts. In contrast, vertically integrated entities practice such bilateral contracts virtually, i.e. between the retail supply and the generation departments within the same company. Of course, bilateral contracts between suppliers and customers has been a common practice.

Therefore, the measures to envisage for assuring revenue streams in the wholesale markets need to consider possible adverse impacts on concentration in the retail market and the survival of small players without vertical integration. At the same time, however, bilateral contracts are essential for hedging uncertainties and finding an effective and stable matching for a firm and affordable energy between suppliers and customers.

RAE is currently designing a new Market Monitoring and Surveillance Mechanism (MMSM) to monitor market power in the wholesale electricity market (on the supply side) and in the retail market (on the demand side). The new tool was under development in 2021, and the introduction of the market monitoring tool is pending. The tool aims to verify and diagnose whether the market operates in a cost-reflective way and whether the degree of market competition is sufficiently intense. Via dedicated monitoring indices, flagging rules and data processing, RAE will perform close to real-time market monitoring and efficient assessment of prices, volumes, costs and MP's behaviour. The first version of the tool will operate by October 2021. The completion of the MMSM is planned for the end of 2021.

In the context of case AT.38700 (Greek lignite and electrify markets), the Hellenic Republic has engaged in constructive discussions with the European Commission ("**Commission**") to offer commitments pursuant to Article 106 of the Treaty on the Functioning of the European Union ("**TFEU**"). The contemplated remedy is to address the Commission's competition concerns as expressed by the Commission in its decisions of 17 April 2018 (C(2018) 2104) and of 5 March 2008 (C(2008) 824), taking into account the judgments of the European Courts in relation to the Commission decisions of 5 March 2008 (C(2008) 824) and of 4 August 2009 (C(2009) 6244). The progress of this case is monitored in the context of the enhanced surveillance framework applicable to the Hellenic Republic, and according to the latest June 2021 enhanced surveillance report of the Commission (COM(2021) 528 final) the remedy is expected to be finalized shortly. The Hellenic Republic and the Commission have now concluded in a mutually agreeable commitments text to perform a market test; said commitments intend to address the competition concerns in the relevant market adequately.

The contemplated remedy consists of introducing a measure in the Greek legal order whereby PPC would be selling electricity volumes corresponding to agreed percentages of its lignite-generated output in the same quarter of the preceding year. In particular, PPC would be selling quarterly futures, which would be traded through the forward market of HEnEx or EEX. All trading members under the rules of HEnEx or EEX would qualify as eligible buyers under this remedy. PPC would not be obliged to supply any of the volumes under these products with lignite-fired power generation. This measure is expected to be activated during the last quarter of 2021 (following a decision of the Commission establishing the specific measure in accordance with Article 106 TFEU). It would remain in place for a limited period.

Even though this antitrust case concerns (as the 2008 Commission decision states) PPC's alleged dominant position on the Greek wholesale electricity market maintained through privileged rights to PPC for the exploitation of lignite in Greece, the contemplated remedy is expected to have a positive impact, among others, in the retail market as well. In particular, by way of this remedy, other retail market participants would have access to an additional product in the forward market with the potential of increasing competition in the retail market as the purchased under the remedy volumes shall end up in the retail market to a large extent and at more competitive rates for the consumer.

4.5 Measures to facilitate bilateral contracting and access to RES

Already today, but significantly more in the future, the formation of competitive retail market portfolios will depend on access to energy from renewables. The levelized costs of renewables decrease, as also confirmed in the tenders for feed-in-premium support schemes. At the same time, all vertically integrated (i.e. electricity sellers that own generation capacities) suppliers are become increasingly short (own generation less than supplied energy) as renewables develop. Thus, competition in the bilateral contract markets will in the future primarily focus on private contracts (e.g. contracts for economic differences, power purchase agreements, sleeved or synthetic) of suppliers and customers with providers of renewable energy. The development of storage facilities will certainly support offerings for firm energy supply from renewable energy providers, further facilitating a market for private RES-PPAs. In this context, the competition between bilateral contracts focusing on RES will depend on the purchasing conditions for balancing and complementary energy from the wholesale and balancing markets. Liquidity, deepness and hedging instruments are the essential conditions in the wholesale/balancing markets to facilitate effective retail market competition.

As there is broad agreement about the future of retail market competition, as mentioned above, the State prepares a legal framework and organized market platforms to facilitate the development of a market for bilateral private RES-PPA contracts. Measured by levelized energy production cost, the RES is by far the most competitive power generation source. However, their stochastic availability and mismatch with consumers' load profile pose barriers to the free-market development of RES-based bilateral consumer contracts with the desired volume- and price-related stability. The market for such bilateral contracts is at its infancy, and its growth constitutes a typical "positive externality" case requiring public intervention. The benefits of internalizing the positive externalities are twofold: developing the RES investment on a pure market basis and allowing customers to get access to RES in the most cost-effective manner. Public support aims to remove the barriers and play the role of "market-maker" to achieve a critical mass of bilateral contracts to allow the free market to continue without public support effectively. In this context, special attention is necessary to ensure that energy-intensive users (EUIs) succeed to replace old fossil-based bilateral contracts with new RES-based contracts while preserving supply stability and competitive costs vis-à-vis their foreign exposure. In addition, a market-making initiative of the state to facilitate the emergence of RES-PPAs evolving any customer category is essential to enable favourable financing conditions for the RES investment, which will be a pure merchant endeavour soon.

The envisaged public intervention will comprise (a) development of an organized trading platform for multi-seller and multi-buyer RES-PPA bilateral contracting, (b) public fund to provide state guarantee specifically to energy-intensive industry off-taking of RES via the RES-PPA contracts. The organized market for RES-PPAs will not be mandatory. The RES-PPAs will co-exist in the free market on a bilateral basis. The products traded in the organized market will be typical bilateral contracts for economic differences[3] with physical delivery optionally. The bilateral contracts will be concluded between offerors (electricity companies and aggregators offering firm off-taking energy from RES producers) and demanders (consumers or retailers). The market operator will operate the trading platform and be the initiator for grouping RES offers with specific demand by energy-intensive industries. State guarantees will be granted for these contracts concluded by the energy-intensive industries. This pooling feature will permit getting benefits from economies of scale and flexibility precisely for the industrial consumers. The buyers will be able to complement the hourly profile of RES to match their load profiles and to net it out via free-market bilateral contracts and operations within the organized wholesale electricity markets outside the organized RES-PPA market. The prices of RES-PPA bilateral contracts will clear demand and offers per transaction (initiation by an offeror or a demander).

Concerning long-term (e.g. between 5 and 10- years) RES-PPAs for industry, the state guarantees will act as a complementary measure to encourage contracting within the organized RES-PPA market. The guarantee will primarily aim to match the long-term revenue stream requirement of bank financing with the shorter-term duration of RES-PPA contracts and the uncertainties of private off-taking. Several institutions have pointed out the necessity for such a state guarantee, including the EIB[4], given the limited creditworthiness of off-takers and the contract duration mismatches. Therefore, the guarantee will operate as a "last resort". In addition, the State will consider granting compensation to the strike price of the RES-PPA with an energy-intensive industry calculated as a product of the anticipated ETS carbon price and the volume of CO_2 emissions reduced thanks to the RES-PPA. Eligible energy-intensive industries will be those bearing energy costs above 10% of production costs and exposed to foreign competition. The RES-PPAs will be synthetic contracts: they will be financial (contracts for differences) and, at the same time (optionally) physical, being submitted as nominations

[3] Standard forms of PPA contracts have for instance already been published by EFET (European Federation of Energy Traders) in June 2019 with guidance notes for their application.
[4] European Investment Bank. (2020). Financial Instruments for Commercial PPAs in Europe. Baringa

to the DAM. Therefore, the RES-PPA essentially are forward market contracts but will not be handled through the existing forward market but via the specific trading platform for RES-PPAs.

Participation in the trading platform will not be limited to energy-intensive industries. The purpose of the measure is twofold: (a) market creation to facilitate private RES-PPAs which are important as a successor of the current RES supporting schemes, (b) support of energy-intensive industry to shift to RES from fossils while ensuring lowest possible costs of energy supply.

Additional facilitation measures will concern the encouragement of the Energy Exchange to create financial derivatives and other products based on the organized market RES-PPAs, to allow for secondary trading of RES-PPAs and crowdfunding.

5 Overview of wholesale markets operation

5.1 Current versus previous market design

Since November 1, 2020, the target model applies in Greece to design and operate wholesale and balancing markets. The new market design replaced the day-ahead mandatory pool system, which was in operation since 2005.

The summary of the previous market design is the following: Based on economic offers by individual power plants at prices equal or above marginal costs, the day-ahead mandatory pool was determining the operation schedule of the plants to meet load demand and demand for ancillary services at the lowest possible costs. The algorithm was co-optimizing, energy, balancing and reserves. The financial settlement was based on market equilibrium prices determined by the co-optimization algorithm to balance demand curves and supply curves reflecting the offerings. The participants could not modify offerings in intra-day, and deviations were settled administratively based on day-ahead bids. The allocation of interconnection capacities was entirely the result of explicit capacity reserve auctions. The mandatory pool design was conceived to disclose electricity prices and costs and provide the possibility to new entrants. Due to licensing restrictions, could only be using gas-firing plants to sell electricity to the pool without the need to have a customer basis for recovering the cost of new investment. The design effectively attracted the IPP investment in CCGT plants that exist today. However, capacity remuneration schemes have complemented the investment incentives. Prior to 2012, capacity remuneration has been provided to all dispatchable plants at capacity prices determined administratively. After 2014, the capacity remuneration was provided only to flexible power units (with fast ramping features), resulting from a tendering procedure. The flexibility capacity remunerations had limited durations (less than one year, repeated three times). At present, there is no capacity remuneration in place.

Following law 4425/2016, as amended by law 4512/2018, the new market design comprises a series of wholesale markets, defined and discussed in detail in the following subsections.

5.2 Forward electricity market

5.2.1 Description of the currently applied market design

The forward electricity contracts are futures for electricity purchase and sale with physical delivery obligation as an option. The forward market, operated by the Hellenic Energy Exchange (HENEX), with ATHEXClear performing transaction clearing, offers the possibility of trading both financially-settled and physically-settled forward contracts. The transactions may concern standard products or over-the-counter bilateral contracts, particularly those with physical delivery obligations. The participants can be producers, suppliers, traders, aggregators and consumers.

5.2.2 Assessment of market operation

The purpose of the forward electricity market is to hedge against price fluctuations of the spot markets via longer-term bilateral exchanges at stable prices. However, this market started in March 2020, has no liquidity so far, as no significant contracts have concluded between different entities. The suppliers that own generation assets have preferred to purchase complementary energy from the wholesale market, where average prices are low. The increasing volumes of RES displaces expensive units from the merit order. Spot price spikes are sporadic and do not economically justify the conclusion of bilateral contracts at higher prices than average spot prices. Usually, the strike price of a physical bilateral contract would reflect the total levelized cost of the generator (including marginal, fixed and capital costs), which turns to be higher than the cost of purchasing from the wholesale market.

5.2.3 Measures to consider

A transitional measure applying a 20% cap on physical contracts currently applies, following the regulator's decision. The reason is to ensure sufficient liquidity and adequate pricing in the day-ahead market by avoiding large-scale vertically integrated companies bypassing the organized market, which would be detrimental for non-integrated producers and suppliers who rely on selling and purchasing in the wholesale market. As in a couple of years, the bulk of lignite generation will vanish, there might be scope for revisiting the regulation that restricts the volume of physical delivery contracts. Such contracts, enriched with storage, synthetic private RES-PPAs and other complex portfolios are expected to become a precious instrument for price and supply stability, as well as for investment facilitation.

The rules regarding the operation of the forward market are approved and monitored by the Hellenic Capital Markets Commission.

Greek market participants do participate in forward markets for derivatives and futures but mainly through the European exchange EEX. For example, on June 26, 2021, total one-month futures concluded by Greek market participants amounted to 80 GWh. According to experience gathered from participants, the trading platform for the forward market could be enhanced to support auctions, information and trade-board services with access to several exchanges and brokers and thus could become attractive to Greek trading players. Software extension and enhancement is a proposed measure to increase market liquidity. The operator of the forward market should also develop amd propose new products dedicated to hedging risks specifically for the DAM and the Balancing markets.

As explained, there is no prohibition of bilateral contracts. There is a provisional measure applicable only to vertically integrated suppliers that does not allow nominations (bilateral contracts with physical delivery) to represent more than 20% of the supplier’s portfolio. The purpose of the measure is to increase the liquidity of the DAM and has nothing to do with the forward market. In particular, it does not influence financial derivatives, futures and options that are the main subject of the forward market. The forward market of EEX with Greek participants is already liquid. The forward market is a free marketplace, and the participation is at the discretion of market players; there is no reason for the State to intervene to increase liquidity, as long as the rest of the wholesale markets are sufficiently liquid, which is indeed the case at present.

The forthcoming RES-PPA trading constitutes a specialized forward market that will operate under a different trading platform.

Also, a measure that will increase operations in the forward market is the remedy to the antitrust case mentioned in the section regarding the retail market competition.

It is also envisaged to commission a study to investigate the feasibility of measures that would provide hedging benefits through the forward contracting market to market participants, focusing on the costs of balancing, anticipating the expansion of renewables and the increasing scarcity of balancing resources.

5.3 Day-Ahead Market (DAM)

5.3.1 Description of the currently applied market design

The DAM is an organised market with a total transaction turnover representing above 80% of all the wholesale and balancing markets. DAM is an hourly spot market balancing demand and supply via electricity prices, reflecting the highest generation bid needed to balance the lowest willingness to pay of load representatives. This market allows participants to submit electricity transaction orders with the obligation of physical delivery on the next day. Participants can also declare the energy quantities corresponding to forward-market product transactions in the day-ahead market, irrespective of commitments through the forward products wholesale market or outside it. At the same time, there is implicit allocation of the transmission capacity at interconnections through the coupling of the day ahead markets of European countries.

DAM is a pure energy-only market, and the financial settlement of energy purchasing and selling occurs at market equilibrium prices. The market participants are producers, consumers, suppliers, traders and aggregators. The producers must submit offers for capacity that has not been allocated via the physical delivery nominations. Mandatory hydro production (quantities of water that have to flow out of the reservoir for irrigation and technical safety purposes) enters the supply offering as non-priced must-run power. The outcome of DAM is a generation schedule submitted to the system operator for physical implementation the next day.

Following ACER 04/2017 decision, the DAM market-clearing price floor is set at -500 EUR/MWH and the cap at 3000 EUR/MWh. In addition, a mechanism applies that increases the price cap by 1000 EUR/MWh when the price exceeds a certain threshold fraction.

The Greek DAM is integrated into the pan-European DAM via the Greek-Italy border, and market coupling also applies with Bulgaria.

5.3.2 Assessment of market operation

The DAM transactions have operated successfully so far, as planned. The liquidity is sufficient, and the market prices are cost-reflective. As a result, the market coupling operates smoothly, and price convergence is frequent.

Regarding the liquidity in the DAM, the total traded volumes for the first 8 months of EU Target Model Implementation are 35,539 GWh, equal to approximately 4,442GWh per month. It is worth noting that the corresponding volumes in the IDM, considering LIDA1, LIDA2, LIDA3, are 639 GWh for the 8-months period, equal to approximately 79 GWh per month (statistically, the IDM volumes are considered equal to 1.8% compared to DAM volumes). So, no liquidity issue for the DAM.

The suppliers' structure in the DAM includes the incumbent with a market share of ~64% in total load representation and 20 alternative suppliers, with a total share in load representation of ~36%, nine of them having a market share above 1%. In electricity generation within the DAM, the incumbent has a small share of the total, 3 independent power producers offer energy produced by gas plants and 13

RES Aggregators also participate, representing renewables. Furthermore, 18 different dispatchable units participate in the DAM on average, out of 36 units that are available on average.

As observed from November 1, 2020, until now, the bids submitted by the power plants have been, in general, simple stepwise price-ascending offers (a few times block orders also) and are equal to or higher than the marginal costs (i.e. fuel costs) of the power plants.

5.3.3 Measures to consider

Combined with the limitation of bilateral contracts with physical delivery, the regulatory measures have ensured high liquidity to the DAM transactions, which allowed retailers with no vertical integration to survive and be competitive in the retail market. Following the RAE decision, a transitional measure restricted bilateral contracts (a 20% cap on physical contracts currently applies for suppliers). It is clarified that the restriction applies to bilateral contracts with physical delivery (nominations) only, not to forward contracts (CfDs, futures, and options are unrestricted).

According to section 4.4.2.2 of DAM & IDM Rulebook, for each Supplier with a retail market share exceeding a X% threshold and for each Market Time Unit, the percentage of energy quantities included in the validated Physical Offtake Nominations that correspond to energy quantities of trades on Energy Financial Instruments executed within the Energy Derivatives Market or concluded bilaterally, on the total amount of energy quantities purchased under accepted Day-Ahead Market Buy Orders, may not exceed an A% threshold. The X% and A% values are set annually by a RAE Decision, following a proposal of HEnEx. For 2021, the X% and A% values are set to 4% and 20% respectively pursuant to RAE Decision 1657/2020 (Government Gazette B' 6027/31.12.2020). A new study based on data from an adequate period of operation of the new DAM is expected to be submitted by HEnEx along with its proposal on the X% and A% values by the end of 2021 to be considered by RAE when deciding on the abovementioned values for 2022. Financial trading is absolutely free.

The upcoming phase-out of lignite plants that are too costly to be part of the merit order reduces the possibilities of bypassing the wholesale market by dominant companies, such as PPC. The IPPs have only CCGTs to combine with retail market portfolios. Therefore, the relaxation of the temporary regulatory restrictions regarding the bilateral contracts is justifiable. However, the examination of pros and cons has to carefully consider the possible adverse effects on retail market competition and the survival of small retailers.

Currently, the regulation of bid forms allows for Hybrid Orders, Block Orders, Linked Block Orders and Exclusive Group of Block Orders. Complex orders have not been yet introduced due to the risk of the increasing complexity of the Euphemia algorithm in relation to the common order book. As the DAM is an energy-only market, the determination of the generation schedule does not consider the demand for system reserves and ignore the technical constraints restricting the cyclical operation of plants and their technical minimum power levels, among others. The market design assumes central scheduling, and so the system operator runs a full unit commitment program for the next day to derive the generation schedule at a time framework close to real-time operation. The unit commitment program includes the reserves and the technical constraints and therefore produces a different generation schedule than the DAM. However, the generators and generally the market participants could pre-empt on imbalances to set their economic offers in the DAM to minimize their exposure to imbalance costs; in this manner, the deviations between the DAM and the central scheduling program would diminish. However, the participants in DAM have applied so far only simple bids reflecting marginal costs and thus the pre-emption of balancing has been poor.

As a measure under consideration, there could be scope for allowing complex forms of bids in the DAM to facilitate the market participants to address both the energy and the balancing markets in a more cost-effective manner and thus minimize exposure to high balancing energy. However, this measure depends on the Euphemia algorithm implementation and cannot be adopted by Greece unilaterally.

There is an ongoing discussion between RAE and the Operators for portfolio-based bidding to be introduced. This switch from unit-based will be considered a market reform for further assessment and careful evaluation in the electricity markets reform plan. Since it is considered as a major amendment of the status in place in the DAM, in order to be evaluated properly, the basic principles of the high-level new market model have to be drafted and be consulted with the market participants, while important amendments on the legislation and regulatory decisions currently in place are required.

5.4 Intraday market (IDM):

5.4.1 Description of the currently applied market design

The IDM market allows participants (same participants as in the DAM, excluding traders) to modify their position in the generation schedule, load declarations, etc., close to the time of the physical delivery, by considering events and deviations of the DAM schedule and changes or limitations due to the balancing market, in an aim to reduce their exposure to imbalances costs. The transactions in the IDM concern upward and downward changes, and their financial settlement is based on market equilibrium prices that are common for upward and downward changes. The participants normally pre-empt in their bidding on the technical restrictions of plant operation to avoid imbalances costs. The commitments of the plants deriving from the ISP (see below, ISP is the central scheduling unit commitment program) should meet both energy and reserves demand.

The IDM market-clearing price floor is set at -500 EUR/MWH and the cap at 3000 EUR/MWh. In the regional intraday auctions and the continuous intraday trading, the price bounds will be set at -9999 and +9999 EUR/MWh. For the non-coupled IDM, the bidding and clearing limits (+3.000 €/MWh and -500 €/MWh) refer to the LIDAs, currently in place. According to RAE Decision 440/2019, the technical price limits of the CRIDAs should be aligned with the ones to be adopted in the SIDC, i.e. +9.999 €/MWh and -9.999 €/MWh respectively (ACER's Decision No 5/2017 on the Harmonized Maximum and Minimum Intra-Day Market Clearing Price).

Currently, the IDM performs three intra-day auctions per day (termed LIDAs). The Greek intraday market is not yet coupled with neighbouring markets in intra-day. The Regulator plans to facilitate the introduction of intra-day trading also for the borders with non-EU countries.

5.4.2 Assessment of market operation

The liquidity of the IDM transactions has been limited during the first months of market operation. There is a lack of regional integration of IDM, which will increase market liquidity.

The introduction of additional participation in the market (i.e. traders, demand response, storage, etc.) is the selected approach to increasing intra-day trading liquidity.

The current design has not allowed for the participation of traders in the LIDAs. On December 15th, 2020, the market coupling of the Greek Day-Ahead market to the European markets over the border between Greece and Italy was launched, and on May 11th, 2021, the second DAM coupling was achieved with Bulgaria. LIDAs are local intraday auctions (non-coupled mode). Therefore, regarding the GR-IT and GR-BG bidding zone borders, cross-border capacity is not recalculated after DAM and thus not offered to market participants for trading. The latter will be resolved with the coupling of the

Greek IDM with the Italian one (CRIDAs) and with the pan-European Intraday Continuous Market (XBID).

LIDAs allows, among others, the submission of Sell Orders by Traders, Suppliers and Self-Supplying Consumers which have acquired Intra-Day Physical Transmission Rights in non-coupled Interconnections for energy injection from Imports and the submission of Buy Orders by Traders, Producers, Suppliers, RES Producers and RES Aggregators which have acquired Intra-Day Physical Transmission Rights in non-coupled Interconnections for energy withdrawal for Exports. At the moment, for the non-EU bidding zone borders (Albania, N. Macedonia, Turkey), the option of intraday cross-border capacity allocation via explicit auctions has not yet been activated, though promptly provided in the HETS Grid Code. In April 2021, RAE has requested IPTO to make all necessary actions/activities towards the strengthening of cross-border trade and the allocation of all remaining cross-border capacity to the market participants. To this effect, IPTO has started relevant discussions with the neighbouring non-EU TSOs (OST, MEPSO and TEIAS) and SEE CAO. The current plan is for the Intraday PTR Auctions for non-EU bidding zone borders to be launched during 2022.

5.4.3 Measures to consider

The coupling of the Greek and Italian DAM markets will allow going for complementary regional intraday auctions (CRIDA) planned for September 2021 with a phase-out of country-specific LIDAs. Greece will also participate in the Single Intraday Coupling (SIDC) project (based on the XBID solution platform), which creates a single EU cross-zonal continuous intraday electricity market. Greece will join as part of the fourth wave, and the go-live date is planned for March 2022.

The participation of traders is currently obstructed by the absence of capacity calculation rules and procedures for the non-EU cross borders. It is foreseen to allow participation of traders within the process of completion of the pre-conditions for the implementation of regional intraday auctions including non-EU cross borders.

RES already participates in ID and with the introduction of full balancing responsibility for RES portfolios until XBID, we expect to see more volumes in the ID market and, therefore, higher liquidity. DSR and storage (except for pumped hydro) do not currently participate, however, significant steps have been taken to activate participation in the ID.

DSR integration in the Greek energy market is planned to be introduced at a first - pilot - stage in the Balancing market in February 2022. The integration of DSR introduces specific technical requirements and practical issues with respect to the connection and interrelation of the two different markets that need to be assessed and clarified by the market operators to enable DSR participation in ID. DSR participation is not generally considered as a streamlined process as each Member State follows differentiated approaches regarding its implementation. Greece generally intends to implement best practices that will be tailored to the country’s demand attributes and potentials.

The regulatory framework for electricity storage participation in the Greek market is currently drafted by the Ministry. However, it is in its final stages, and the corresponding legislation is expected soon. Currently, in an effort not to deter market interest or decelerate investments, licensing of such projects is enabled through a transitory procedure which is going to be phased out as soon as the final legislation is adopted.

Pursuant to section 5.1 of DAM and IDM Rulebook, the LIDAs, currently in place in non-coupling mode, are consistent with the number and timing of the corresponding CRIDAs, to be easily replaced by the latter when they are launched.

According to the information provided by HEnEx and IPTO, CRIDAs are scheduled to go-live on 21.09.2021 (first trading day) at the same time with the inclusion of Phase A of the Local Implementation Project 14 (LIP14) to XBID. The Operators will submit to RAE during Q3 2021 all documents proving their contractual and technical readiness. RAE will issue the decision on the go-live date of the Intraday Market coupled operation (CRIDA) in September 2021 considering the relevant recommendation by HEnEx and IPTO.

Continuous trading is an objective to pursue in combinations with regional integration of intra-day trading. In addition, the forthcoming full introduction of RES is likely to enhance liquidity of intra day trading, as the RES will be under full balancing responsibility. Another measure aiming at enhancing liquidity of intra-day trading is to allow participation of traders, in relation to Article 20 of the Regulation (EU) 2019/943. Participation of traders in the intra-day market (intra-day capacity auctions in non-EU borders with Greece) is targeted for 2022. Intraday capacity is scheduled to be introduced through explicit allocation in the non-coupled Greek Borders with Albania, North Macedonia, and Turkey. The plan is to have fully implemented all the intra-day liquidity enhancing measures by 2022.

In the meanwhile, some technical open issues between HEnEx and IPTO have to be resolved. The detailed Market Design (roles, interface etc.) has to be completed. The Local Trading System and XBID-ISP integration specifications have to be defined, and the necessary technical and operational adjustments to IPTO IT systems have to be concluded.

Furthermore, the DAM-IDM Rulebook and methodologies' amendments regarding XBID's implementation will be submitted by HEnEx, if needed, and RAE will issue the relevant approval decision after consulting the documents with the market participants. After completing the bilateral, FiT and SiT IT tests and relevant dry runs with the market participants' , the Operators will submit to RAE during Q1 2022 all documents proving their contractual and technical readiness. RAE will issue the decision on the go-live date of the Intraday Market coupled operation (SIDC) in Q1 2022 considering the relevant recommendation by HEnEx and IPTO.

5.5 Balancing Market (BM)

5.5.1 Description of the currently applied market design

The balancing market includes the balancing capacity market (to ensure that sufficient reserves are available), the balancing energy market (to activate energy in real time to ensure that the system is in balance while meeting demand for energy and reserves and respects all technical plant operation constraints) and the imbalance settlement process (to allocate revenues and costs of the balancing market and to market participants). Participants are required to submit bids with a physical delivery obligation for their total available capacity, both in the balancing energy market and the balancing capacity market.

Table 10 presents an overview of the design of the balancing markets, which comprises three steps running sequentially. The following products are used in the Integrated Scheduling Process (there is no use of Replacement Reserves):

a) upward and downward Balancing Energy without distinction between manual FRR and automatic FRR;
b) the following Balancing Capacity products:
    i. Upward and downward FCR,
    ii. Upward and downward automatic FRR, and
    iii. Upward and downward manual FRR.

Table 10: Overview of the Balancing Market

Procedures executed sequentially from left to right			
Name of the procedure	Integrated Scheduling Process (ISP algorithm)	Balancing Energy Market (RTBM algorithm)	Settlement of Balancing Energy & Capacit7y, and Imbalances
Time resolution	30 minutes	15 minutes	15 minutes
Objective	Balancing capacity procurement	Balancing energy procurement	Metering and Settlement
Ancillary services	FCR, aFRR, mFRR	aFRR, mFRR	
Remuneration rule	Capacity remunerated pay-as-bid	aFRR remunerated pay-as-bid mFRR remunerated at market clearing prices	Single Imbalance price Volumes, prices and settlement amounts calculated
Real time operation	Unit Commitment Schedule (from the ISP)		

In the Balancing Energy Market, the following products are used:

a) The upward and downward Balancing Energy for manual FRR, which is activated by executing the manual FRR process for each manual FRR Time Unit. The Balancing Service Providers submit Balancing Energy Offers for manual FRR, that is, Balancing Energy Offers that correspond to the activation of the manual FRR.
b) The upward and downward Balancing Energy for automatic FRR, which is activated through the operation of the Automatic Generation Control. The Balancing Service Providers submit Balancing Energy Offers for automatic FRR, that is, Balancing Energy Offers that correspond to the activation of the automatic FRR.

In the context of the Balancing Market reform towards the participation of IPTO in the MARI platform, the local mFRR balancing energy product characteristics have to be amended in order to be fully compliant with the standard mFRR balancing energy product according to ACER Decision No 11/2020. The amendment includes most of the local product characteristics such as the full activation time, the deactivation period, the way of activation, the min and max delivery period etc. Furthermore, for the participation in the PICASSO platform, the local aFRR balancing energy product has to be equally fully compliant with the standard aFRR balancing energy product according to ACER Decision No 11/2020, especially regarding the full activation time, which has to be amended from 7.5 minutes to 5 minutes from 18.12.2024.

According to IPTO, the need for the definition and use of specific balancing energy and reserves products has to be evaluated in case the standard products are not sufficient.

The TSO defines the volume of reserve requirements for each balancing capacity (reserve) product, namely for FCR (Frequency Containment Reserve), up and down, aFRR (automatic Frequency Restoration Reserve), up and down, mFRR (manual Frequency Restoration Reserve), up and down, except for RR (Replacement Reserve) which does not yet apply in Greece. The TSO determines the system needs for Balancing Capacity for FCR, automatic FRR and manual FRR, as defined in the "Methodology for Determination of Zonal/Systemic Balancing Capacity Needs". The above volumes are contracted within the ISP. The mFRR balancing energy is activated by the mFRR process (RTBM) every 15 minutes or with a direct activation. aFRR is activated by the aFRR process (AGC) real time.

The volumes of FCR, aFRR and mFRR reserves are awarded to the market participants through the ISP, based on the requirements published by the TSO on a 30-min granularity. For the period of the 8 months of EU Target Model operation, the requirements for both directions for FCR are 992 GW with a daily average of 4.1 GW, for aFRR 6,757, with a daily average of 28 GW and for mFRR 8,009 GW with a daily average of 33 GW.

The activated balancing energy derives from the Imbalance Settlement Procedure and the total volumes considering the 8-months period for aFRR and mFRR activated balancing energy are 1,475 GWh and 4,343 GWh, respectively. Also, the corresponding volumes of the daily average balancing energy activation for aFRR and mFRR are 6.2 GWh and 18.2 GWh, respectively.

The participants submit volume-price balancing capacity offers per reserve product, provided that they are eligible, technically and operationally, and have capacity available for reserves. The offerors are dispatchable generating units.

Demand response, electricity storage systems and RES are not yet eligible to offer reserves; however, regulatory, technical and operational preparations are ongoing to allow such participation in the reserve offerings by Q1 2022 (for DSR and RES, whereas for storage regulation is pending). Currently, DSR and RES are eligible to participate in the Balancing Market. However, the required technical details are not yet in place to ensure a level playing field for the above technologies. The high-level design for DSR participation was put in the public consultation by IPTO in August 2020. The process to design the market, adapt the regulatory framework, the systems, and the procedures for the efficient participation of Demand Side Response (DSR) and RES in the Balancing Market is ongoing and is planned to finish until Q1 2022. DSR and RES will be able to participate in the Balancing Market on equal terms with the conventional Balancing Service Providers, both in balancing energy and balancing capacity markets.

Regarding storage the Ministry of Energy and Environment has established a working group in order to prepare the legal framework for the participation of storage in the electricity market. The report prepared by the group will be published by the Ministry soon. Modifications in the Balancing Market Rulebook are planned to be completed by Q3 2022, while the technical implementation of the systems and procedures is planned for Q1 2023.

Participation and bids in the balancing capacity market take place day-ahead. The participants submit their offers for balancing capacities in an Integrated Scheduling Process (ISP). The ISP procedure operates at least three times daily, namely once after clearing the DAM and after the first LIDA, and twice after the other two LIDAs. For balancing capacity awarded to them, the bidders receive as compensation an amount calculated using their offer price; i.e. a pay-as-bid auction applies. Upon selection, they have an obligation to commit to the respective capacity as a reserve. Otherwise, they are not compensated for the awarded capacities resulting from the ISP results since the remuneration considers the real-time availability as indicated from the real-time operation (SCADA system).

The minimum limit for bidding prices in the balancing capacity is zero. The maximum limit for these prices is currently +3000 EUR/MW/hour, which is likely to increase up to +9999 EUR/MW/hour after the operation of continuous and complementary regional intraday trading. The rationale is to align the bidding price boundary to balance the opportunity costs of intra-day trading and the bounds applicable there.

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

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

The Imbalance Settlement Procedure defines the remunerations and, generally, the settlement for balancing energy, balancing capacities and imbalances. The remuneration basis results from the RTBM algorithm that implements the Balancing Energy Market, which runs in compliance with the outcome of the Integrated Scheduling Process (ISP).

The dispatchable generation units eligible for balancing energy provision submit upward and downward balancing energy offers to the ISP. At present, the bounds applying on the prices of the balancing energy bids are significantly lower, between +4240 EUR/MWh and -4240 EUR/MWh, than the range defined by ACER in 2020 Guidelines, namely the range +99999 EUR/MWh for the maximum and -99999 EUR/MWh for the minimum. IPTO has set the following technical limits for the submission of the balancing energy offers:

- 1st period: from 1st November 2020 until the implementation of CRIDAS or XBID [-4.240 , +4.240] €/MWh
- 2nd period: once the implementation of CRIDAS or XBID is fulfilled (Q1 2022) until the participation in MARI or PICASSO platforms [-9.999 , +9.999] €/MWh
- 3rd period: once the participation in MARI or PICASSO platforms is fulfilled [-99.999 , +99.999] €/MWh

Therefore, price caps in the balancing market will be aligned with price caps set for the European balancing platforms once IPTO starts participating in any European platforms.

The procurement of balancing capacity is paid as the submitted bid. More specifically, participants submit their offers for balancing capacity in the ISP, which runs at least three times daily. The ISP awards balancing capacity to Balancing Service Entities. For each Balancing Service Entity and each Imbalance Settlement Period, the upward and downward Balancing Capacity supplied for FCR, automatic FRR and manual FRR is calculated taking into account:

- The price of the Balancing Capacity Offer segments that have been accepted based on the last valid ISP execution.
- The availability in MW of the Balancing Service Entity for the provision of the service in real-time.
- The percentage of a time period within an Imbalance Settlement Period that the Balancing Service Entity was available for the provision of balancing capacity in real-time.

Manual FRR balancing energy is paid at market-clearing marginal prices. Prices and quantities are generated by the real-time mFRR balancing market procedure (not the ISP). Automatic FRR balancing energy is paid as the submitted bid, but it receives at least the price of mFRR balancing energy. In more detail, the debits or credits to the Balancing Service Providers for the activated Balancing Energy for manual FRR are calculated as the product of the quantity of the activated upward/downward Balancing Energy for manual FRR and the marginal Price for upward/downward Balancing Energy for manual FRR. The debits or credits to the Balancing Service Providers for upward Balancing Energy activated for automatic FRR is calculated as the product of:

a) the quantity of upward Balancing Energy for automatic FRR

b) the higher value between the price for the upward Balancing Energy for manual FRR and the Balancing Energy Offer for automatic FRR corresponds to the quantity of upward Balancing Energy activated for automatic FRR.

The debits or credits to the Balancing Service Providers for downward automatic FRR is calculated as the product of:

a) the quantity of downward Balancing Energy activated for automatic FRR and

b) the lowest value between the price for the downward Balancing Energy for manual FRR and the Balancing Energy Offer for automatic FRR corresponds to the quantity of the activated downward Balancing Energy for automatic FRR.

The Imbalance Settlement Process is an ex-post market procedure, which determines the revenues or payments of balancing demanders (Balancing Responsible Parties - BRPs) and the revenues or payments of balancing suppliers (Balancing Service Providers - BSPs). The allocation to the two categories is dynamic per settlement period. The imbalance settlement period has already been set to 15 minutes since 1st November 2020. The imbalance price is the weighted average price of activated balancing energy in the relevant direction (upward or downward) for manual and automatic frequency restoration reserve. The imbalance price for a settlement period derives by dividing the sum of credit or debit for balancing energy in EUR by the volume of activated balancing energy in MWh. If there has been no activation of balancing energy, the imbalance price reflects the value of avoiding balancing energy activation. Bids accepted for non-energy balancing purposes (e.g. re-dispatching or for voltage control) are paid as the submitted bid. Any additional cost (difference of bid price and imbalance price) is recovered through an uplift account that ensures financial neutrality TSO.

The marginal price of mFRR balancing energy is already taken into account for the calculation of the Imbalance Price. The Imbalance Price per Imbalance Settlement Period is calculated as the weighted average price of the activated Balancing Energy for manual and automatic FRR for that Imbalance Settlement Period in the predominant direction (upward or downward).

The imbalance price calculation is already in compliance with the ACER Decision 18/2020, ‘Methodology for the harmonization of the main features of imbalance settlement’. According to the above decision, ‘Each connecting TSO shall use for the imbalance price for negative imbalance, the weighted average approach and/or the maximum price approach, based on the prices and respective volumes listed in paragraphs 3 and 5 for positive activated balancing energy…’. Bids accepted for non-balancing energy purposes (e.g. re-dispatching or for voltage control) are not taken into account in the imbalance price calculation. Bids accepted for non-energy balancing are paid as the submitted bid, and any additional cost (difference of bid price and imbalance price) is recovered through an uplift account that ensures financial neutrality of the TSO.

5.5.2 Assessment of market operation

The experience from the Balancing Market operation so far indicates that the balancing energy costs, which are paid by balancing responsible parties (finally paid by consumers) and are revenues of balancing service providers (mainly they are revenues of producers), are significantly higher, compared to the previous market design, which, however, was co-optimising energy and reserves. The total amount (turnover) of balancing energy remuneration is several times higher than the total amount (turnover) of balancing capacity remuneration. The marginal prices for upward balancing energy have been much higher than for downward balancing energy, as expected. Thus the compensation received by generators is significantly positive for the re-dispatching implied by the ISP and reflected into the balancing energy market.

The main reason for seeing large volumes of balancing energy relates to the high magnitude of deviations between the real-time generation schedule and the one derived from the DAM, the latter resulting from pure energy cost merit-order with practically insufficient pre-emption of reserves and other technical constraints by the participants. The intra-day, lacking liquidity at present, has not been able to modify the generators' positions significantly to approach the real-time generation schedule. Consequently, the DAM's generation schedule does not respect reserves and technical operation constraints, which implies that significant re-scheduling (re-dispatching is necessary). There has also been a network limitation in Peloponnese due to a delay of completion of the high voltage loop grid (due to local opposition that led to court cases for a small distance connection at a specific location), which made impossible the real-time operation of units located in Peloponnese at full capacity. Another cause of deviations relates to over-voltage issues occurring in the Northern system of Greece at low load times, which implies must-run instructions for a few lignite plants to maintain voltages within a reliable range.

5.5.3 Measures to consider for the balancing energy costs

After observing that marginal prices for balancing energy (as defined through the Imbalance Settlement Procedure considering the output of the RTBM algorithm) are quite higher than the DAM prices, which relate to network issues and probably to over-priced bids, the Regulator adopted in January 2021 an amendment to the balancing rules and imposed a zero EUR/MWh bidding floor for downward movement of balancing energy. The measure is provisional and has effectively induced a certain reduction in total balancing energy costs. The removal of the price range limitation depends on the completion of the Peloponnese network, for which a deviation routing is underway.

The price floor for both upward and downward balancing capacity was set to -4240/MWh at the beginning of the new market on 1st November 2020. In February 2021 the Regulator adopted an amendment to the balancing rules (RAE's decision no 54/2021) and imposed a bidding floor of zero EUR/MWh for balancing energy. According to RAE's decision, the measure is provisional and will be removed upon completion of the Peloponnese network.

According to the "All TSO's proposal on list of standard products for balancing capacity for frequency restoration reserves and replacement reserves pursuant to Article 25(2) of the Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing ("EBGL Regulation"), capacity offers can have zero or positive values. Thus, the price floor for balancing capacity offers is set to zero. For the period until the participation in XBID the price cap for balancing capacity offers has been set to 3000 EUR/MW/hour, which is the upper limit of the energy offers in the Intraday Market. Once XBID is in place for Greece, the maximum price cap will be set to 9999 EUR/MW/hour (Q1 2022). According to the relevant Technical Decision for the offer limits, the price limits for balancing energy offers will be between 9999 EUR/MWh and -9999 EUR/MWh after implementing the regional and continuous intra-day trading. Subsequently, after joining the MARI or

PICASSO platforms for exchanging manual and automatic frequency restoration reserves, respectively, the bounds will align to the ACER's Guidelines.

Implementing the new Market Monitoring and Surveillance Mechanism, probably towards the end of 2021, would, in principle, mitigate the risk of strategic bidding behaviour in the wholesale markets and ease the removal of the current price restrictions with a lower risk over-pricing.

Given the large discrepancy between the DAM market-driven schedule and the ISP generation schedules, the IPTO is studying market design improvements without reaching a final proposal so far. As mentioned, balancing energy and capacity procurement operates via the ISP that co-optimises energy and reserves and takes place only close to real-time. A candidate market improvement option could be to consider reserve capacity procurement in day-ahead via separate auctions; the tender prior to the day-ahead market will optimise reserve procurement based on offers by eligible providers of reserve (generators and other resources); the selected reserve suppliers will take the obligation to maintain their reserve capacity possibilities during real-time system operation; penalties will apply in case of non-compliance; the selected reserve capacity suppliers will take care to submit complex and portfolio bids to the DAM to maintain the reserve capacity offer available and minimise exposure to imbalances and penalties. The additional tendering before the day-ahead is meant to facilitate participants in the pre-emption of capacity reservations for real-time and thus the adaptation of their DAM economic and capacity offerings; in such a manner, the discrepancies between DAM market-driven schedules and ISP generation schedules may reduce, to the benefit of overall cost optimisation and minimisation of re-dispatching. The reform should combine with the introduction of portfolio-based bids in DAM and terminate the restriction on unit-based bidding. To further facilitate the management of portfolios, including capacity reserve supply commitments, it may also be necessary to expand the nomination of portfolios in the DAM. The platform's operator would remain HENEX, of course, but the platform would require a significant adaptation. The day-ahead separate auctions for reserve capacity would then require establishing a nomination platform to allow for nominating awarded balancing capacity intended to be available within the ISP, which will further facilitate supporting portfolio bidding in the auctions and secondary capacity trading. The design of this reform is not yet mature. It requires a detailed study of advantages and disadvantages. Among the possible drawbacks of the reform, it is worth mentioning the risk of liquidity reduction of the DAM, the risk of increased concentration in the market as non-integrated (i.e. without ownership of generation) suppliers and traded may be adversely affected in their purchasing of energy from the wholesale markets. The possible significant advantages stem from increasing the market-based possibilities that market participants could exploit to achieve higher efficiency and economies of scale. An expected positive outcome would be the reduction of balancing costs to the benefit of costs for consumers.

More specifically, to reduce the significant discrepancies between the schedules from the Day-ahead market and the ones from the Integrated Scheduling Process and thus reduce the volumes for balancing energy, the following measures are envisaged:

a) Reduction of the recourse to General Constraints to address network system constraints and preserve the secure system operation (i.e. Peloponnese congestion, over-voltages in Northern Greece) will reduce re-dispatching.

b) The foreseeable exploitation of complex and portfolio bidding by market participants in the Day-Ahead.

c) A potential measure is the separation of the energy volumes activated for balancing needs and re-dispatching, according to the TSO's obligation to implement Article 13 of Regulation (EU) 2019/943 effectively.

d) Another measure is the introduction of distinct reserves auctions at the day-ahead level.

Re-dispatching is defined in the regulatory framework as a measure, including curtailment, that is activated by one or more transmission system operators by altering the generation, load pattern, or both, to change physical flows in the electricity system and relieve physical congestion or otherwise ensure system security. As mentioned, system constraints (e.g. Peloponnese and overvoltage threats), as well as events related to the RES, are factors that increase re-dispatching, which exerts undesirable impacts on the efficient operation of the market, resulting in distortion of market prices. Non-energy related re-dispatching distorts price signals as units that are not technically able to produce electricity (through downwards re-dispatch) take part in the price formation process. In contrast, actually producing units are remunerated outside the ex-ante market (through upwards re-dispatch). If re-dispatch is systematic, electricity prices do not reflect actual supply and demand. Units are systematically re-dispatched down after clearing in day-ahead market coupling due to structural congestions. The introduction of re-dispatch considerations before the day-ahead via tendering procedures for reserve procurement could help to mitigate the re-dispatching discrepancies. In addition, there is scope to apply a method for avoiding price impacts of re-dispatching due to system constraints.

The envisaged reform is to fully implement the regulation provision about "The resources that are re-dispatched shall be selected from generating facilities, energy storage or demand response using market-based mechanisms and shall be financially compensated. Balancing energy bids used for re-dispatching shall not set the balancing energy price." The integration of all resources in the balancing market will allow applying re-dispatching beyond generation units. In addition, the approach detailed in the following paragraph shall implement the requirement about impacts on balancing energy prices.

The recommended approach is to apply a flagging approach, i.e. the identification of energy and non-energy actions. The main objective of flagging and tagging is to minimize the extent of price implications arising from non-energy actions on the energy imbalance price. In other words, the imbalance price should be a reflection of marginal cost incurred for issuing balancing energy actions only. The balancing instructions, in addition to meeting the mismatch in generation and load (energy only actions), could also be for non-energy reasons as well. For example, a unit might be asked to deviate to provide voltage support or contribute towards reserve requirement. The rationale is that since this instruction was issued for non-energy purpose, the price of this instruction shouldn't affect the imbalance price. A complex methodology is necessary to fully implement the flagging approach, and for the integration in the software and algorithms. Flagging of re-dispatching will be in place by December 2021, but the settlement will be implemented in the first quarter of 2022 as it requires significant modifications of the IT software.

Participation of demand-side response in the balancing market is planned for February 2022. Participation of RES with full balancing responsibility is for March 2022.

5.5.4 Measures to consider for shortage pricing function

Article 20(3)(c) of Regulation (EU) 2019/943 requires that the Member States shall consider introducing a shortage pricing function for balancing energy to recover administrative costs and availability costs associated with balancing services. The principle of a shortage function is to ensure that prices can rise to the level of Value-of-loss-of-Load in times of scarcity. This could be achieved by adding a "scarcity adder" to the balancing energy auction's balancing price. However, it seems that it is not enough to introduce the scarcity adder as a component only of the imbalance price. In this manner, the balancing trading parties do not see the scarcity price signal within the balancing market, but only ex-post. In the currently applicable European regulation, the shortage pricing function is meant to be a no-regret measure that is internal to the markets, improves the market design, and may address the inherent “missing money” disease that markets with high variable RES are likely to suffer. Shortage (or scarcity) pricing measures may co-exist with capacity remuneration mechanisms, but precedence matters in favour of the shortage pricing mechanism. Under this approach, the introduction of scarcity price adders is under consideration for the balancing energy prices that remunerate BSPs and the imbalance prices charged to BRPs.

The shortage pricing function based on a scarcity adder applicable on the imbalance settlement procedure contemplates that the balancing energy price should add a component to the marginal cost (derived from the respective bid) of the most expensive resource used to meet balancing energy requirement. The component to add should be a multiple of the equilibrium price of the balancing capacity market; i.e. in other words, the adder is a non-zero proportion of the reserve price. The proportionality factor (the multiple) should be inversely related to the system's remaining real time reserve capacity, as estimated within the settlement period (that today has a horizon of 15 minutes from real-time). The adder would apply to the settlement for both BRPs and BSPs. An issue to address in this respect is the approach for aligning the energy balancing prices and the imbalance prices; this would require a market-clearing price approach, instead of pay-as-bid, for the capacity balancing auction and the application of marginal market prices, augmented by the adder, instead of an average pricing approach, for the imbalances price.

In addition, the administrative extreme shortage price setting for exceptional system conditions will operate as follows: when a system inadequacy condition is detected with respect to a balancing period, the IPTO resorts to rolling disconnections of the load either in the scheduling phase of the Balancing Market or, with at least 30 minutes notice, in the real-time operation and sets the imbalance settlement price automatically at the level of the Value of Lost Load (VOLL).

The application of a shortage price function cannot be unilateral in the context of coupled markets. The MARI and PICASSO platforms do not assume co-optimisation of energy and reserves. In contrast, the most effective way of implementing the shortage price function mentioned above is the derivation from energy and reserve co-optimisation, which at the same time can address the aim of aligning energy balancing and imbalances prices. It is consequently questionable how to apply shortage pricing effectively in a harmonized manner within the coupled markets.

As mentioned already, shortage pricing will co-exist with capacity remuneration. However, the adoption of the former is preceding the latter. The increasing integration of RES in the power system to reach high levels by 2030 reduces marginal wholesale prices and increases demand for operating reserves. The gas plants offering the reserves, together with emerging providers such as storage and demand response, are increasingly stressed in a system with growing RES, forced to operate at high ramp rates and frequent shutdowns and start-ups. The CCGT unit faces the highest economic pressure under such conditions. Such plants require a stable revenue stream for reserve resources to recoup rising fixed operating costs and, ultimately, capital costs. However, significant uncertainty surrounds revenues at scarcity times for system reserves, as investors are reluctant to trust financial viability exclusively on sporadic price spikes. The removal of price caps and other barriers and introducing a shortage pricing function for reserves help reduce the uncertainty surrounding the revenue stream occurring only at scarcity times. However, these measures cannot fully address the investment reluctance and the possible mothballing of flexibility providing resources.

The Greek state envisages the design of reliability options in exchange for capacity remuneration awarded to power resources. The reliability options effectively address market power mitigation to avoid unnecessary costs for consumers and imply a clawback mechanism for returning to consumers costs occurring in the wholesale and balancing markets above strike prices included in the options.

The shortage price is under examination. In any case, the potential implementation of scarcity pricing will be supplementary to the operation of a capacity remuneration mechanism, where overcompensation "claw-back" clauses will be provided.

A shortage pricing study has already been carried out by IPTO in November 2019 in the context of the commitment of the Greek State in the technical MoU with the European Commission to assess the introduction of a shortage pricing function in the Greek Balancing Market. The study was based on data regarding the precedent design of the Greek electricity market. At least one year of data regarding the operation of the current market model is required to perform a new study for shortage pricing. Therefore, the new study will be available by the first quarter of 2022.

5.5.5 Overview of market coupling in the South-East European region

Before introducing market coupling, cross-border capacity on one hand and electricity, on the other hand, had to be purchased separately. This means that a trading participant had to reserve cross-border capacity first before using this capacity to transport the electricity bought in a second step. Market coupling, in essence, applies implicit auctions for energy in which market participants do not individually receive allocations of cross-border capacity. Instead, they bid for the electricity on the wholesale energy market to determine the balance between demand and supply, including the available cross-border capacity among the constraints. Then, as long as the cross-border capacity constraint is not binding, the least cost optimization determines the generation schedule in the coupled system simultaneously. Thus electricity flows across the border from the low-cost generation to the high-cost generation, while the market-clearing price is uniform. However, suppose along this process the cross-border capacity constraint becomes binding. In that case, the electricity flow cannot continue until price convergence, and so the cross-border regions clear at different prices as if there has been a split in the market. The current DAM market in Greece implements the market coupling automatically by integrating the cross-borders with Italy and Bulgaria.

The explicit capacity auctions continue on all cross-border links of Greece. The auctions operate annually, then monthly and at higher periodicity (for the non-EU borders), depending on the availability of capacities. Use-it-or-sell-it rules apply for capacity reservation, for which payments derive from auction clearing prices. Therefore, the upper bounds of capacity auctioned reflect the net available transfer capacities.

The explicit capacity auctions also apply to the borders of Greece with Italy and Bulgaria. The amount of netted capacity left without a firm reservation applies as an upper bound on the market-clearing algorithm of the DAM. It constrains the cross-border flows derived from the wholesale electricity auctions implicitly. The market coupling algorithm applies the NTC and not the flow-based approach.

Importers holding firm reservations on cross-border links other than the coupled markets submit volume and price offerings to the DAM to allow electricity flowing.

Traders for flows across the borders of coupled markets can participate in the explicit interconnection capacity auctions, reserve capacity at a specific price and then submit a nominated schedule for electricity supply and load. But for the same borders, the traders can hold bilateral contracts for economic differences with generators cross-border and profit from the implicit auction-based allocation of interconnection capacities to avoid paying for a reservation. This latter approach seems like the dominant one in the current trading practices for the borders of the coupled markets.

As mentioned above, market coupling for intra-day trading and for the exchanges of balancing capacities and energy is among the plans of the IPTO for implementation in the coming few years.

5.5.6 Measures to consider for regional integration

The four transmission system operators (TSOs) of the South-East Europe and Greece-Italy Capacity Calculation Regions (CCRs) – which are ESO-EAD (Bulgaria), IPTO (Greece), Terna (Italy), and TSCNET shareholder Transelectrica, the TSO from Romania – have established the sixth European Regional Security Coordinator (RSC) in the northern Greek city of Thessaloniki. The new RSC goes by the name of Southeast Electricity Network Coordination Centre (SEleNe CC). Each TSO participates equally in the share capital of the new company. SEleNe CC provides all regional RSC services for both CCRs according to the requirements of the EU guideline on capacity allocation and congestion management (CACM). The main tasks of SEleNe CC – just as with Baltic RSC, Coreso, Nordic RSC, SCC, and the Munich based RSC TSCNET Services – are: coordinated security analysis, outage planning coordination, coordinated capacity calculation, (very) short-term adequacy forecasts, individual and joint grid modelling, and data set delivery.

Market design changes are required to participate in the MARI and PICASSO platforms. Pursuant to the provisions of article 62 of the EBGL, IPTO has requested a derogation from the provisions of articles 20(6) and 21(6) of EBGL concerning the implementation of the European platform for the exchange of balancing energy from frequency restoration reserves with manual activation, or else ‘MARI’ platform, and the implementation of the European platform for the exchange of balancing energy from frequency restoration reserves with automatic activation, or else ‘PICASSO’ platform. The requested derogation period is two years, thus until the 24th of July 2024. Participation in the European platforms MARI and PICASSO is a challenging project that requires significant and extensive modifications to systems, infrastructures, and procedures and the terms and conditions of BSPs and BRPs, and other regulatory framework changes. The significant challenges for the participation to MARI and PICASSO platforms are the following:

- Adaptation of systems and procedures to be compatible with the characteristics of mFRR and aFRR standard products. Investigation of whether usage of specific products of balancing energy is needed or whether standard products are sufficient.
- Switching to the mFRR and aFRR standard products may require reviewing the methodology for calculating the Balancing Capacity needs to ensure the System's required level of security.
- Extensive upgrading of the systems, infrastructure and procedures related to the mFRR and aFRR is necessary to be able to collaborate with the European platforms.
- Extensive upgrading of the systems, infrastructure, and procedures related to the Settlement of Balancing Market is required to take into account the volumes and prices regarding activations by the European platforms and local activations.
- Design and development of a bid conversion software are required, which will convert the ISP bids into balancing energy bids for aFRR and mFRR to be submitted to the MARI and PICASSO platforms.
- Implementation of fallback procedures when the procurement of balancing services or the coordinated activation of balancing energy on MARI and PICASSO fail.
- Design and develop new software that will continuously inform MARI and PICASSO platforms about the available cross-zonal capacity until the implementation and operation of the corresponding European CMM platform.

Participation in the EU balancing platforms (MARI/PICASSO) is targeted for July 2024 due to technical complexity and IT software adaptations.

There is a solid commitment to perform full integration in the European platforms. The current request from the TSO to delay this process is to mid-2024 due to technical difficulties that are recognized as related to the timeline of IT infrastructure adaptation, which is considerably complex. Extensive upgrading of the systems, infrastructure and procedures related to the mFRR and aFRR is necessary to be able to participate with the European platforms.

IPTO S.A. officially passed all the interoperability tests on 22nd of June and is a participating IGCC TSO. Due to the absence of any electrical border connected to IGCC, IPTO S.A. does not net any imbalances with other participating IGCC TSOs.[5]

5.5.7 Participation of demand response, RES and storage in the balancing markets

Greece operates an interruptibility scheme approved by the EC in 2014 and recently prolonged for a second time until September 30, 2021. Under the scheme, Greece compensates large energy consumers for voluntarily reducing their consumption when the security of electricity supply is at risk. IPTO contracts a segment of 400 MW and another for 400 MW, each defined for different durations of power reduction. The contracted large consumers receive fixed compensation as an availability remuneration determined via three-monthly auctions in exchange for the possible load reduction. The maximum auction clearing prices were 45000 EUR/MW/year and 65000 EUR/MW/year for the two segments, respectively, for up to 48 hours and 1 hour interruption. This out-of-the-market measure is phased out after the end of September 2021.

Price-elastic offers to the DAM by load representatives are possible but have not yet been practiced. The retail suppliers have not yet applied dynamic pricing to consumers in the absence of smart metering infrastructure. Dynamic pricing is expected to develop in the future as part of the business models that retailers will apply in the future.

The smart metering investment program of the HEDNO, supported by the Recovery Funding plan, will support dynamic pricing business models. The forthcoming partial privatization of HELDNO will further facilitate the investment program on smart metering.

The participation of demand response (DSR) is currently not included in the wholesale markets, also not included yet in the intra-day and balancing markets. Infrastructure (regulatory framework, IT systems and adequate metering) allowing such participation is under preparation, with an expected timeframe in February 2022 (for the Balancing Market). The DSR implementation plan, with a timeline until February 2022, is meant to include DSR participation in the balancing market for aggregators with load portfolios or RES (and later storage, depending on pending regulation) portfolios. In particular, the IPTO has a going plan to propose an adaptation of regulatory framework, systems, and procedures for the efficient participation of Demand Side Response (DSR) and RES in the Balancing Market until the end of 2021. Specifically, the deadline for DSR participation has been set one year after the initial milestone for the go-live of the target model, i.e. September 2021, while the actual date on which the new market model has been launched was November 1st 2020. Regarding the participation of storage in the electricity market, IPTO is currently preparing the necessary modifications in the regulatory framework to be consulted with the participants soon after adopting the relevant legislation.

DSR is expected to go live by the February 2022 in the Balancing Market at a first - pilot - stage for mFRR products. The integration of DSR introduces specific technical requirements and practical issues concerning the connection and interrelation of the two different markets that need to be assessed and clarified by the market operators (NEMO & IPTO) to enable DSR participation in ID (and in DA).

Milestones and pending issues:

- A precondition for IPTO to update the existing Baseload Methodology.

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5 https://www.entsoe.eu/Documents/Network%20codes%20documents/Implementation/IGCC/20210625_Press_release_ADMIE_go-live.pdf

- Technical specifications for LV smart meters drafted by HEDNO
- Demand Aggregator Scheme (Regulatory issues, Licensing, Metering requirements, competencies and commitments.

Result expected: According to IPTO's conservative scenario for DRS participation,[6] the evolution of DSR participation beginning from 2021 is depicted in the following table[7]:

Table 11: DSR participation scenarios

(MW)	Base Case	High Case
2022	60	300
2023	70	310
2024	80	320
2025	100	340
2030	250	500
2035	500	750

RES supported by Feed-in-Premium contracts are now protected from the settlement of imbalances, but in the coming months, with the expiration of the transitional provisions of the Balancing Market Regulation the RES will become fully exposed to balancing responsibility and the related prices.

RES supported by feed-in-tariffs contracts that have terminated are subject to balancing responsibility and balancing prices. The same applies to DAPEEP as an aggregator of RES units supported by feed-in-tariffs.

The merchant RES have full balancing responsibility.

In a stepwise manner and with a final deadline of mid-2022, the market reform will ensure that the following resources will participate in the balancing market:

1) RES units or portfolios of distributed RES Units for the provision of mainly downward Balancing Energy, but also upward Balancing Energy from specific technologies with the possibility of upward regulation (e.g. biomass and biogas stations, and / or small cogeneration stations),

2) Consumer's or distributed load portfolios for the supply of upward Balancing Energy (through consumption reduction), mainly by High and Medium Voltage customers with the technical capability to reduce consumption power in case of the relevant order, and later through load representatives

3) Storage stations, hydro pumping, batteries (with or without functional integration with RES units) and other storage facilities to provide all types of reserves and Balancing Energy in both directions,

6 Financial analysis of the wholesale markets

As mentioned in previous sections, the target model design consists of a sequence of wholesale market transactions which trade and deliver electricity and reserves. The forward contracts market is illiquid and is omitted in the financial analysis. The DAM and IDM markets are price-cleared auctions. The

[6] Public Consultation on Assumptions of the new National Resource Adequacy Assessment of IPTO (2021). Available online: https://www.admie.gr/nea/diaboyleyseis/dimosia-diaboyleysi-ypotheseis-kai-dedomena-tis-neas-meletis-eparkeias-ishyos

[7] Source: Public Consultation on Assumptions of the new National Resource Adequacy Assessment of IPTO (2021

reserve procurement is a pay-as-bid auction and operates together with balancing energy adjustment from the results of which a procedure determines the energy balancing and the imbalances prices.

The objective of the financial analysis in this section is to provide aggregated data about the source of revenues per type of wholesale market and per category of power plant and how the costs, including all types of costs, compared to revenues. The revenue data are official, but the cost data are approximative and unofficial, based on experts' information. The data are aggregated for lignite, gas and hydropower plants. Further disaggregation could risk disclosing confidential information.

The financial analysis concerns the 6 months from November 2020 to April 2021, during which the target model design has been applied for the first time.

The turnover (total amount of payments) of the DAM, during the said period, represented 75% of the sum of all wholesale markets. The IDM had a small turnover of only 0.2% of the total. On the other hand, the balancing energy, which is a part of the BM, had a significant turnover of 25.1% of the total. The balancing capacity represented 2.9% of the total. The net revenues (or payment by generators) for imbalances, penalties and other levies have been negative in the said period and represented -3.1% of the total.

As mentioned in a previous section, the revenues of generators from balancing energy have been considerably high in this period as a result of two reasons: firstly, the significant discrepancies between the DAM and the ISP generation schedules and secondly, the considerable need for re-dispatching due to the limitations in the operation of the high voltage circuit in Peloponnese and other (e.g. over-voltages) system constraints. It would be logical to consider that the impacts of both drivers are likely to decrease soon. The market players should be acquainted with the market functioning. By pre-empting on requirements corresponding to a unit commitment generation schedule, would submit suitable offers in the DAM to diminish exposure in imbalances. The full operation of the high voltage circuit foreseeable for the near future will remove the network limitations. Also, balancing resources, such as storage and demand response, will diminish scarcity and mitigate the market power of those generators that submit highly-priced bids in the balancing market.

Consequently, it is logical to expect a significant reduction of generators’ revenues from the balancing energy part of the BM. The prices seen in Greece are significantly higher in the first six months of target model operation than balancing energy market prices in the rest of the EU. For the reasons mentioned, the high prices observed in Greece for balancing energy will reduce and align to EU averages.

Table 12: Summary data on financial analysis of revenues from wholesale markets and comparison to costs

Period of 6 months (Nov.2020 - Apr.2021) Target model		Lignite	Gas	Hydro	TOTAL
Physical system data					
Operating capacities	MW-net	2,816	5,213	3,042	**11,070**
Electricity generation - scheduled	GWh	3,603	9,015	2,503	**15,120**
Electricity generation - real time	GWh	3,650	9,069	2,508	**15,227**
Capacity factor (% of time at max capacity)	%	29.6%	39.7%	18.8%	**31.4%**
Revenues from wholesale markets					
Day-Ahead Market	'000 €	193,535	599,163	119,146	**911,844**
Intra-Day Market	'000 €	4,175	-1,777	-176	**2,223**
Balancing energy	'000 €	49,032	159,946	95,963	**304,941**
Balancing capacity	'000 €	2,729	18,362	14,256	**35,347**
Imbalances, penalties and levies	'000 €	-8,048	-22,311	-7,793	**-38,152**
Total revenues under target model	'000 €	241,424	753,383	221,396	**1,216,203**
Estimated costs (as calculated by the advisor)					
Fuel and non-fuel variable cost	'000 €	265,598	566,221	0	**831,819**
Fixed Maintenance and Operation costs	'000 €	57,322	39,400	6,843	**103,566**
Annual equivalent cost of capital (WACC 7.5%)	'000 €	58,431	175,498	195,420	**429,349**
Total costs	'000 €	381,352	781,118	202,264	**1,364,734**
Profits or Losses					
Revenues minus fuel and variable costs	'000 €	-24,174	187,162	221,396	**384,383**
Revenues minus fuel, variable and fixed O&M costs	'000 €	-81,497	147,762	214,552	**280,818**
Revenues minus total costs	**'000 €**	**-139,927**	**-27,736**	**19,132**	**-148,531**
Indicators per unit of production					
DAM and IDM per unit of production	€/MWh	54.2	65.9	47.4	**60.0**
BM per unit of production	€/MWh	12.0	17.2	40.8	**19.8**
Total revenues per unit of production	€/MWh	66.1	83.1	88.3	**79.9**
Fuel and variable costs per unit of production	€/MWh	72.8	62.4	0.0	**54.6**
Total costs per unit of production	€/MWh	104.5	86.1	80.6	**89.6**
Revenues minus total costs per unit of production	**€/MWh**	**-38.3**	**-3.1**	**7.6**	**-9.8**
Indicators per unit of capacity					
DAM and IDM revenues per unit of capacity	€/MW-year	140,419	229,213	78,231	**165,143**
BM revenues per unit of capacity	€/MW-year	31,047	59,855	67,352	**54,586**
Total revenues per unit of capacity	*€/MW-year*	*171,466*	*289,068*	*145,583*	***219,729***
Fixed O&M and capital costs per unit of capacity	€/MW-year	82,211	82,455	133,003	**96,281**
Total costs per unit of capacity	*€/MW-year*	*270,846*	*299,710*	*133,003*	***246,564***
Revenues minus total costs per unit of capacity	**€/MW-year**	**-99,380**	**-10,642**	**12,581**	**-26,835**

Source: Official data from ENEX and IPTO for revenues and physical operation; Approximative and unofficial estimations for costs

As shown in Table 12, the generators receive revenues mainly from the day-ahead market and secondarily from the balancing energy market. The revenues from the latter are uncertain, as explained above. Balancing pre-emptive bidding behaviour in the energy-only market will considerably decrease the generation scheduling differences from the unit commitment. In contrast, the removal of network congestions will further decrease re-dispatching. As it will be shown below, the balancing energy market prices have been significantly high during the first six months of the target model operation. The balancing market prices have reflected bidding prices with high mark-ups above marginal costs, behaviours that correspond to the scarcity rents in the balancing market, as scarcity conditions occurred in the said period for the reasons explained. The conditions that are likely to prevail shortly will tend to balance energy scarcity and the volume of the market to diminish. The shortage pricing function, expected to be added to the market design, will apply sporadically and thus will not offset the declining volume and scarcity trend. Therefore, the balancing energy revenues are likely to decrease despite the shortage pricing function.

Table 12 shows that the revenues from the DAM and IDM have not been sufficient to allow a recovery of variable and fixed operation and maintenance costs of the thermal plant generators. The absence of any margin above operating costs is due to the marginal prices in the DAM mainly because of the so-called merit-order effect of the renewables. The supply curve of generators, sorted in ascending order of price bids laying above marginal costs, comprises the GTCC plants (with similar bids more or less), the lignite plants (more expensive marginal costs due to the EU ETS carbon prices) and the open cycle gas turbines. Dispatchable hydro usually bid at the upper margin of the expected merit order and thus is rarely a price-maker. The supply curve applies to the net-load (load minus RES) and not to the total load; the net-load being significantly lower than total load, in particular during the daylight, intersects the supply curve at plant types much less expensive than the plants that would be needed to meet the total load. The RES impacts on the merit order will accentuate in the future as RES increase. Therefore, the margins above the plants' operating costs scheduled to meet net-load are low and will further diminish in the future.

The lignite plants, in particular, forced to operate at minimum technical levels to serve district heating and contribute to meeting electricity demand at certain times, incurred very significant losses regarding the recovery of operating costs (fuel, variable and fixed O&M costs). The lignite plants received from the DAM and IDM 25.5% lower amounts than their fuel and variable costs during the same period. When including fixed operation and maintenance costs, the revenues from DAM and IDM were unable to recover almost 40% of the costs. The average variable operating costs (essentially fuel costs) of lignite plants have been approximately (according to estimation) equal to 72.8 €/MWh, which corresponds to a calculation based on: the average unit cost of lignite 11 €/MWh-fuel, average net thermal efficiency 0.33, the average price of EU ETS carbon emission allowances 35 €/tCO2 and emission factor of lignite 0.37 tCO2/MWh-fuel (the emission factor per MWh net electricity produced is on average 1.12 tCO2/MWh-e). The revenues of lignite plants from DAM and IDM have been only 54.2 €/MWh. The additional revenues of lignite plants from the balancing market (BM) have been 20% of all revenues from wholesale markets, i.e. from the BM, the lignite plants got 12 €/MWh on average. Therefore, the total unit revenue of 66.2 €/MWh was insufficient to cover the unit fuel and variable cost (loss 6.6 €/MWh). When also including the fixed operation and maintenance costs, the average loss has been 22.3 €/MWh. Suppose the accounting of costs includes capital-related expenses (depreciation, financial, provisions, etc.). In that case, total wholesale market revenues of lignite plants are 40% lower than total costs, including variable, fixed and capital costs, in the examined period of six months. The calculation finds that the lignite plants incurred a loss of 140 million € in the six months, equivalent to a loss of 99.4 thousand €/MW-year.

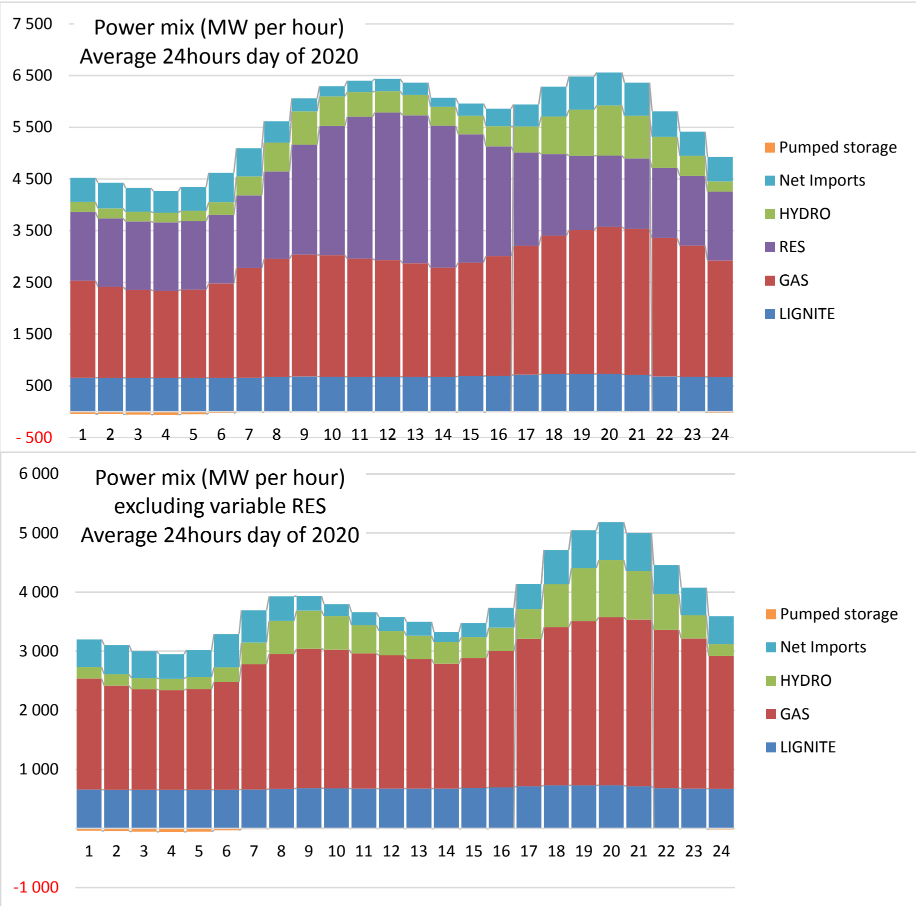
The CCGTs represent the large majority of the gas plants, the rest being open cycle gas turbines. The majority of the CCGTs are relatively new plants commissioned in the period 2008-2014, featuring high energy efficiency when operating baseload but bearing a significant reduction of efficiency when operating close to their technical minimum power level. Seven of the 10 CCGTs feature a single-shaft design; the rest have more than one gas turbine and operate at lower energy efficiency. There are relatively small differences among the CCGTs regarding the marginal costs; the marginal costs at full load capacity are the lower bound of the economic offerings by the plants and, as the large majority of bids do not include mark-ups, due to intense competition, the differences of the marginal costs between the CCGTs are generally slight. Gas prices are also similar for the plants due to strong competition in the gas market.

In contrast, the GTs do feature high marginal costs, but their inclusion in the merit order of the DAM is rare. As also the hydropower plants submit bids slightly above the gas plant expected to be included in the hourly merit order of the DAM, the margins between the marginal price of the DAM and the marginal costs of the CCGTs are small, except during a few scarcity times when GTs act as price makers at a higher level. Moreover, as the renewables increase, the GTs and the expensive CCGTs are less and less included in the DAM merit order, decreasing the margins of the CCGTs as less efficient units are kicked out. The gas plants got 79% of their wholesale market revenues from the DAM and IDM (IDM has been a loss for gas plants) and 21% from balancing energy. However, the revenues from balancing capacity, which has been small in magnitude, has been offset by payments for imbalances, penalties and levies. Therefore, the bulk of gas plant revenues come from the merit order of the DAM; the revenues from balancing energy are uncertain in the future, as the relatively high amounts received in the six-month period were due to exceptional circumstances.

The cost and bidding structures and the implications of the increasing RES on net-load explain that the revenues from the DAM and IDM minus operating costs are small for the gas plants; this is expected to continue and deteriorate in the future. The difference between revenues and operating costs, as estimated for the six-month period from November 2020 to April 2021, has been positive for gas plants. The margin has been 24% above the sum of fuel and fixed operation and maintenance costs. However, the margins remaining after deducting operating costs from gas plant revenues have not been sufficient to recover the annual-equivalent capital costs. As the plants are relatively young, capital cost recovery is an essential issue for their survival (due to debt servicing). In addition, of course, it is crucial for attracting new investors in the future, as required by the NECP plan of Greece. The outcome has been a loss for the gas plants, which amounts to 10.6 thousand €/MW-year of gas plants. The gas plants received an overall 83.1 €/MWh per unit of production, and the total costs have been 86.1 €/MWh, which leads to a loss of 3.1 €/MWh.

The financial analysis for the six-month period Nov.2020-April 2021 shows that the hydropower plants (including pumped storage) have achieved a tiny but positive overall profit, corresponding to 12.58 €/MW-year. The revenues from DAM-IDM have represented 53.7% of their total revenues from the wholesale markets for hydropower plants. Another significant source of revenue, 43% of the total, has been the balancing energy, with balancing capacity representing a small fraction, 6.4%. The hydro pumping installations, in particular, had negative financial balances, as the revenues when discharging energy have been lower than the payments when charging, also given that pumping also implies energy losses. The reason for this loss is that the price differentials in the wholesale markets, DAM and BM, have been small; it is a usual symptom of markets with high RES, as it is among the merit order implications of the RES. An implication is that it would be difficult to see the price differentials in the wholesale markets acting alone as a financial driver to achieve IRR hurdle rates that would justify storage investment in the future. The cost structure of hydropower installations is almost exclusively dependent on capital expenditures, as variable and fixed operating costs are negligible. Due to their capital intensiveness, estimating annual-equivalent capital costs is very uncertain. It depends on the time length and the amounts of capital expenditures that a hydropower plant owner would be seeking to recover. Based on a conservative estimation of capital costs to recover, the financial analysis for the six-month period finds a positive net outcome for the hydropower plants, which is equivalent to a net result (revenues minus all costs including capital costs) 12.58 thousand €/MW-year. The hydropower plants have received revenues of 88.3 €/MWh produced and incurred costs estimated at 80.6 €/MWh produced. According to the estimations shown in Table 12, all the dispatchable power plants together had a negative net result of 9.8 €/MWh on average, calculated as the difference between all revenues from wholesale markets minus all costs, including operating and capital costs. Therefore, the loss corresponds to 148.5 million € in the six-month period and represents a missing money percentage of 11%.

Figure 7: Generation schedule according to the DAM in an average 24 hours daily interval in the six-month period Nov.2020-April 2021

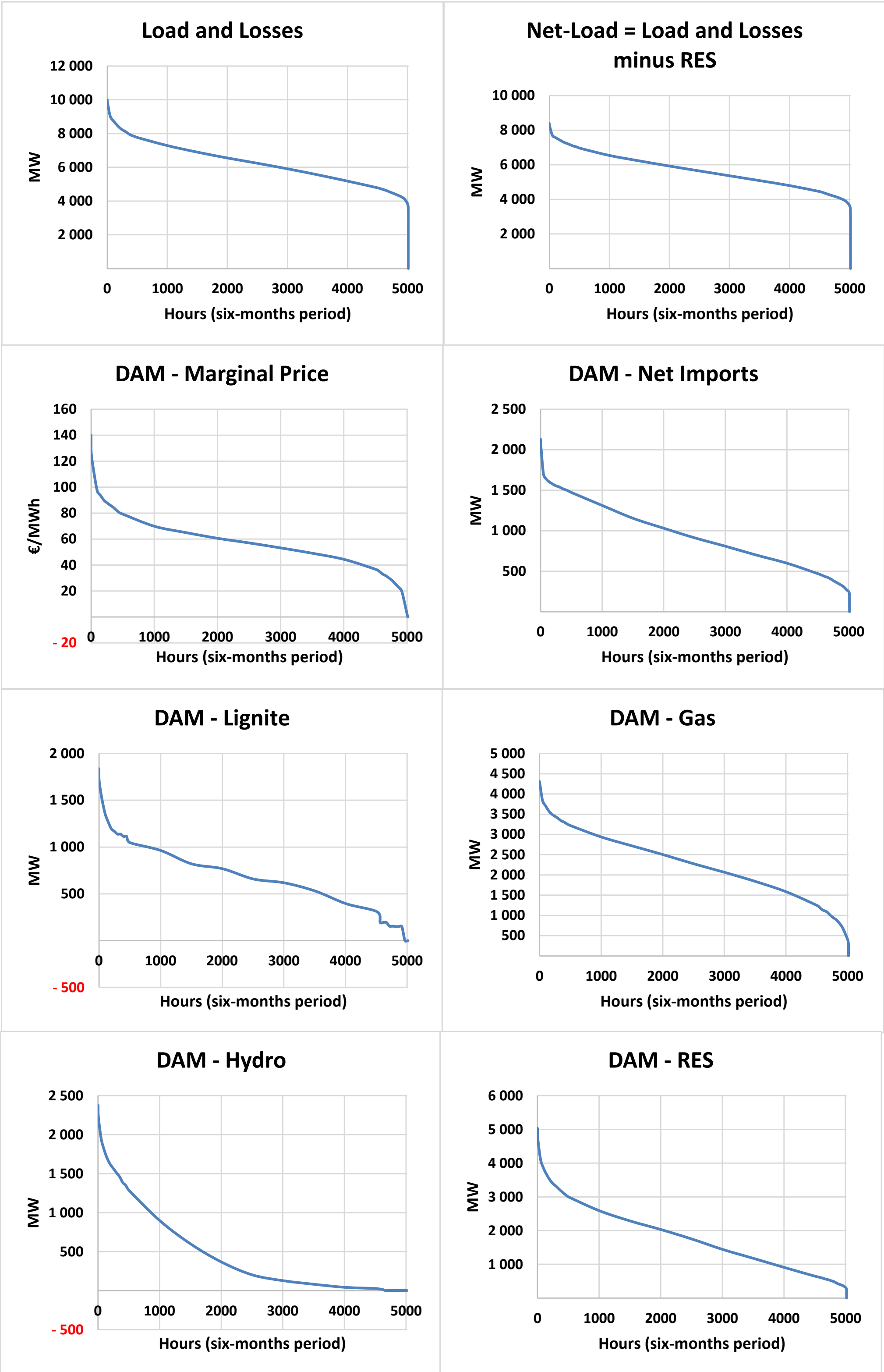


Source: Official data from ENEX

The illustration shown in Figure 7 explains the variation of marginal prices in the DAM auctions. The hydropower discharge energy due to mandatory water outflows in the majority of time slices in a day, except at peak times due to lack of RES during the evening. However, even at such peak load times, the marginal prices leave a small margin for revenues above costs for the gas plants. The lignite plants operate in baseload to deliver district heating and system reserve purposes although they would have been excluded from the schedule based on pure marginal costs. Therefore, lignite receives revenues determined by generation with lower marginal costs than the full cost of lignite fuel. The net imports perform a shape that follows the net-flows and thus help moderating the marginal market prices.

The average DAM marginal price has been 48.8 €/MWh during the six-months period and the standard deviation over the average has been 36%. Over less than 5% of total hourly time slices, the DAM marginal prices exceeded the total unit cost of CCGT power plants. Only less than 1% of the time slices the DAM marginal prices exceeded the total unit cost of lignite power plants. The price duration curve of the DAM marginal prices has been relatively flat. The frequency of price spike occurrence is small already today and will further decrease as RES increase in the system, as foreseen in the NECP plan.

Figure 8: Duration curves for load, marginal market prices and generation schedule, according to the DAM

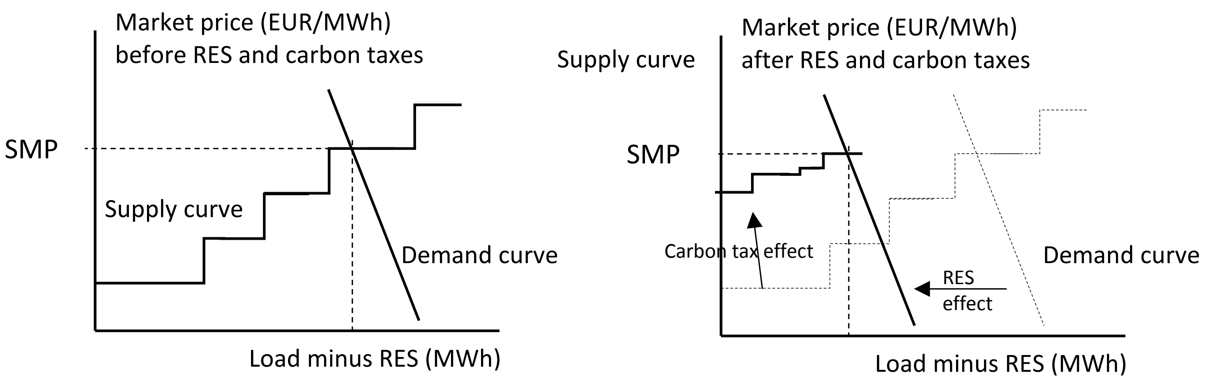


Source: Official data from ENEX

7 Market failure justifying a capacity remuneration mechanism

Day-ahead energy markets are designed to work as competitive markets. But a truly competitive market of this kind depends on the diversity of generating system's cost structure and essentially on the diversity of generators' marginal costs. Only at scarcity supply times fixed costs matter and may drive market prices above marginal costs. As scarcity times are rare and sporadic, marginal costs prevail in the large majority of market instances. Then, revenues above marginal costs depend exclusively on the diversity of marginal costs. In other words, the revenues of a given generator depend on whether competitors with higher marginal costs are included in the scheduling resulted from the merit order.

Figure 9: ***Generators' cost-supply curve before and after renewables and carbon tax***



In a market with high renewables and a phase-out of lignite or coal plants driven by high carbon dioxide emission taxes, as illustrated in Figure 9, the competitors remaining in the day-ahead market have similar marginal costs that reflect the cost of the natural gas, including carbon costs. The only diversity of marginal costs is energy efficiency, depending on the age of the plant and the gas procurement conditions; however, these factors lead to quite similar marginal costs under competitive market conditions. So, the diversity of marginal costs is hugely smaller in a high renewables system than in conventional markets, like those seen in past years.

The rest of the power resources, such as storage and demand response, perform load shifting (e.g. from peak to load valleys) to arbitrage market prices. Thus, they influence market prices but are not price-setters and do not help increase the diversity of marginal costs; on the contrary, they tend to reduce diversity at scarcity times.

The cost structure of a market with high renewables and gas-firing plants for balancing has a peculiar market price duration curve. The curve is fully flat except in a few hours (not more than 10-50 hours per year. Storage and demand response operating when supply scarcity occurs further flattens the market price duration curve. It is then evident that such a market cannot guarantee capital and fixed cost recovery for the thermal-dispatchable gas plants. They could earn to recoup marginal costs, but revenues above marginal costs are highly uncertain as occurring only at rare scarcity times. There are no revenues above marginal costs even for cost-competitive thermal-dispatchable technologies due to the low diversity of marginal costs among the remaining operating units.

The net load (load minus RES) is increasingly reducing as RES deploy. The net load is the marketplace for power units with a non-zero marginal cost. As the net-load market volume reduces, such units operate less and less. At the same time, the system needs them to be spinning to deliver capacity reserves, with required volumes increasing as RES deploy. Therefore, the cost structure of gas plants is heavily dominated by fixed maintenance and capital costs, with variable costs representing a smaller fraction of total costs over each year.

A producer facing fixed costs has a decreasing total average cost curve. For the reasons mentioned above, the gas plants have a cost supply structure that decreases with the quantity sold in a market with high renewables. As a result, the power resources covering the majority of the load have no marginal costs. Thus, with high RES, the power system practically has only resources with decreasing cost supply functions.

Industries with high fixed costs – especially with investments that involve specific assets that, due to this specificity, are sunk costs – are not good candidates for hosting competitive markets, especially if they also have meagre variable costs. In the short run, price equals marginal costs, being then always close to zero. As a consequence, in such markets, prices will always stay lower than average costs. As a result, firms will never break even: market price is always a point on the marginal cost curve, but this curve never actually crosses the total unit cost curve. If firms never break even in the short run in shallow variable cost markets, no equilibrium can be expected in the long run. If some firms leave the market, price levels do not change, remaining equal to the industry's marginal costs – that is close to zero – as the remaining will maximize production. The situation only changes if firms exit the market en masse. In this case, installed capacity will be lower than demand, and thus, prices may rise above marginal costs. But this will not attract new investments. Given that these investments would include high sunk costs (due to assets' specificity), who would undertake them in markets where prices tend to be too low whenever sufficient supply is adequate?

A market with a homogenous product in a fixed cost-based industry with high sunk costs is only sustainable in three cases: i. when firms have revenues from alternative sources, ii. When firms have the market power to deter potential entrants and influence prices, iii. in regulated markets.

Energy market design should be fundamentally linked to each country/region generation sector's cost structure. Only in this way can energy markets work adequately: remunerating generators appropriately and signalling the need for capacity expansion. This spot market design emulates the classic competitive market with some fidelity and has worked for several years in several European countries. Yet this market design would not work correctly in a system where all generators have very low or zero variable costs, like when renewables share is significantly high, and only gas plants exist to balance the renewables. In such systems, spot prices would always remain low, and companies would never break even. A transition to a system where sunk fixed costs are predominant and where generation with very low or zero variable costs dominate destroys the basis for day-ahead markets. Rare and occasional revenues from balancing zero variable cost generation are the only opportunity for gas power plants to survive. Political uncertainty surrounds revenues at rare times when spike prices occur in the balancing markets, including at the few hours per year when balancing prices may approach the value-of-lost-load.

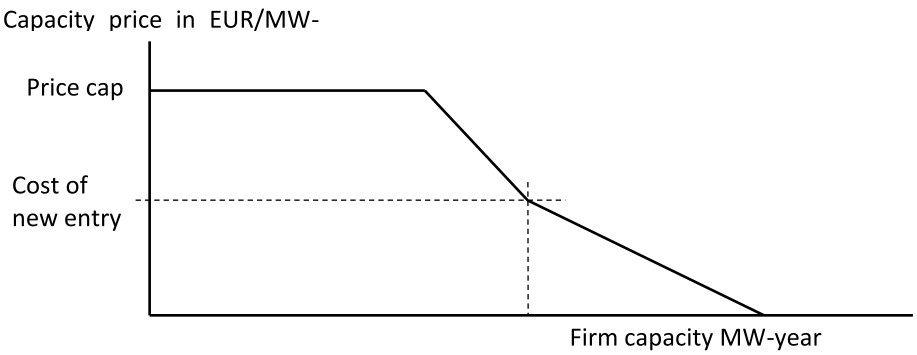
It is an illusion to postulate that a purely free market would provide the missing money to generators if the regulation does not obstruct spike prices to climb up to the value-of-lost-load. As economic theory suggests and business practices validate, the rare spike prices are seen by potential business investors as extremely uncertain revenue sources. Business investors would not dare to invest unless volatility hedging financial instruments replace the spike price revenues with smooth revenue streams to make them confident. Such financial instruments do not exist in reality, particularly for generators that serve system balancing purposes rather than private energy off-taking portfolios. Scarcity pricing, as an add-on to the balancing market, is helpful, but it is doubtful if alone can attribute the required degree of certainty to revenue streams, as still, net revenues occur sporadically and at uncertain time intervals only when the system reaches scarcity conditions. In addition, the increasing renewables imply that CCGTs operate more and more in an intense cyclical manner, every day, with fast ramping rates and frequent start-ups and shutdowns. Maintenance costs increase when stressing the units, and, most importantly, the CCGT operates practically as system requirements dictate and not as retail portfolios would need. Under such stressful conditions, the CCGT cannot enter retail portfolios to supply energy following the customer's load profile or complement RES-PPAs for specific corporate sleeved bilateral contracts. Such revenue opportunities are unfeasible for CCGT owners in a system with high variable RES production.

In addition, system balancing is a sort of a public good: investing to balance the system helps competitors hedge price rises and be competitive vis-à-vis energy off-takers while not having invested in balancing the system. Under such typical public good (i.e. system reliability) circumstances, nobody dares to invest unilaterally to help system reliability. This is because adding generation capacity to reduce the probability of disruption entails private costs to a part of the market willing to pay for the extra security. Still, at the same time, the reduction of disruption probability creates a benefit that accrues mainly to parties other than the capacity-adder or the demand-reducer. Thus, following public goods economics, a purely free market will under provide such a system service.

The lack of explicit economic signalling for capital-intensive investments in electricity generation is that regulators need to create out-of-the-market mechanisms to provide fixed revenues to investments considered priorities. Such mechanisms aim to guarantee that generators cope with fixed costs. Thus, it is explicable why the creation of capacity remuneration mechanisms is top of market reform in most EU countries. However, capacity remuneration mechanisms are out-of-the-market public intervention, even if justified to provide to consumers benefits from a positive social externality, associated with the construction of sufficient generation capacity to achieve system reliability and energy supply adequacy.

Even if fully justified, any public intervention suffers from the principal-agent disease and entails an agency cost that consumers will have to pay. The state (or the regulator) acting as the "principal" cannot guarantee, despite tendering procedures, that the providers of firm power capacities, the "agents", will price the capacity firmness service at actual costs and in compliance with the maximum social surplus objective of the "principal". Asymmetric information between the principal and the agents about the costs, asymmetric risk-hedging utilities and the bargaining or market power of the agents explain the occurrence of an agency costs under all possible conditions.

***Figure 10:** Demand function to remunerate firm capacity*



Given this difficulty, the state or the regulator may add cost-reducing features to the capacity remuneration mechanism. Primarily, three cost-reducing feature are essential following the experience from several countries: (a) The introduction of a capacity demand function with decreasing slope in the capacity remuneration tendering procedure; (b) the introduction of a reliability option contract to avoid excessive earnings in the spot balancing markets; (c) the broadening of capacity offering by accepting capacity offers by electricity storage and demand response in the capacity remuneration tendering process.

Based on a regulatory decision, the demand function (Figure 10) determines the price of capacity remuneration at the intersection with the supply function, which results from adding the generators' capacity bids in a cost ascending order. The demand function decreases with the increase in total firm capacity to remunerate as the reserve margin also increases. It may feature an upper bound to mitigate the market power of offerors and kink points to support a significant number of generators at prices close to the cost of new capacity entry.

In exchange for capacity remuneration, the supported generators offer the system operator reliability options, clawback contracts obliging the generator to return wholesale and balancing market payments above a strike price defined in the contract. It is a market power mitigation measure that protects consumers from paying twice for generators' capacity costs.

As illustrated in Figure 11, the generators having received capacity remuneration get the obligation to offer their total available capacity in the wholesale and balancing markets. The clawback contract acts as an incentive not to bid above marginal costs and hedges against market power. Therefore, it is essential to apply the clawback provisions to all stages of the organized market in a high renewables system.

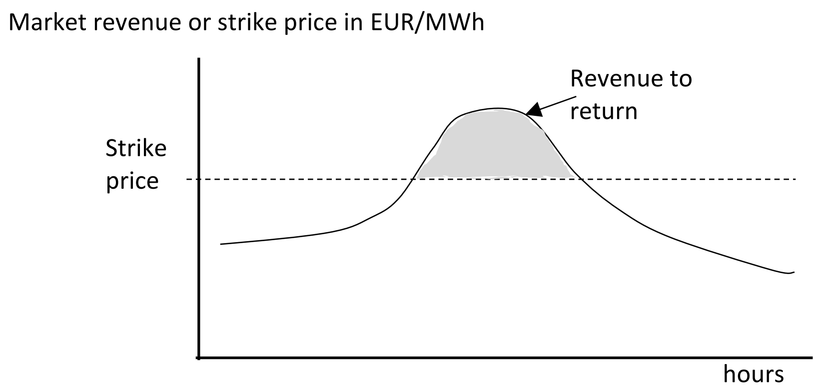
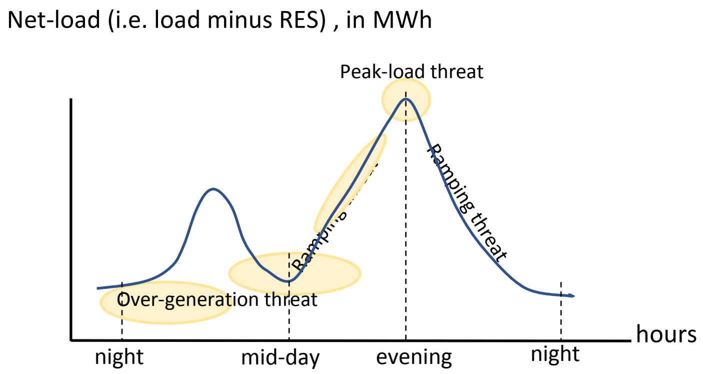


Figure 11: ***Clawback in a typical reliability option***

Increasing penetration of renewables has brought with its profound changes in the variability of the system. Consequently, assessing the capacity adequacy of a system has become more complex than before. The traditional approach of assessing capacity adequacy only for peak load times is not sufficient anymore and cannot ensure reliability in a system with high amounts of variable RES. The modern approach (Figure 12) to capacity adequacy is multi-dimensional and needs to assess at least the following issues:

1. Downward ramping capability (risk of loss of ramping capability)
2. Upward ramping flexibility (risk of loss of ramping capability)
3. Minimum stable generation flexibility (over-generation threat)
4. Peaking capability (risk of loss of peak load)

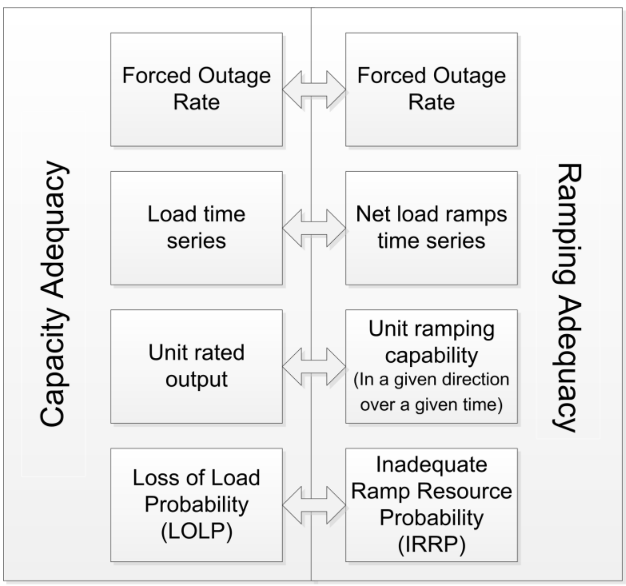
Figure 12: ***The net-load shape and the capacity adequacy threats in a system with high RES***



Flexibility assessment requires measuring demand for flexibility by the system and supply of flexibility by power generation resources, storage, interconnections and demand response. The metric of flexibility refers to net-load, load and losses minus non-dispatchable (variable) renewables and must-take generation (CHP). The dispatchable resources, net imports and demand response have to meet the net-load. In systems with high vRES, the variability of renewables adds considerable challenges to system reliability due to high ramping requirements. The system needs to control sufficient resources able to perform fast ramping individually. The systems with high penetration of renewables require flexible generation units connected to the AGC system with ramping capabilities higher than the threshold of at least 8-10 MW/min during a sufficiently long interval. Storage and demand response resources are also crucial for system flexibility because they shift load and thus reduce net-load peak and increase valleys, thus helping both reduce ramping and avoid over-generation and curtailments.

The capacity adequacy threats referring to peak-load times and high ramping times call upon enriching the probabilistic assessment needed to determine the optimal capacity availability. Fig. 4 illustrates the methodology of probabilistic ramping assessment that has to complement the traditional probabilistic capacity adequacy assessment.

Figure 13: ***Extension of probabilistic assessment***



The capacity mechanism will include storage and demand response, which will help flexibility and will incentivize gas-firing plants as the single remaining technology (due to regulation and GHG targets) for thermal plants. Therefore, the goal of increasing flexibility is de-facto served by the capacity mechanism. In addition, as the flexibility requirements are better satisfied if a large number of gas plants remain in operation, with negligible energy production but with high power reserve services supply, the capacity mechanism must incentivize both old gas plants to remain in the market not to mothballing. The same applies even more to new gas plants required to be built, as foreseen in the adequacy study.

To conclude, capacity remuneration mechanisms need to be permanently part of the market design to support large scale deployment of renewables. The design has to include a capacity demand function, combined with a reliability option to ensure clawback provisions and incentivize system flexibility resources.

For the short term, a couple of years, a strategic reserve mechanism is in addition imperative to address the security of supply threats due to the economic mothballing of lignite power plants, heavily penalized by the surge of carbon dioxide prices. However, such a mechanism, applicable on an exceptional and temporary basis, will compensate strictly only for the minimum fixed maintenance and operation costs needed to maintain the units under retirement in a cold reserve regime.

8 Appendix A: Memo regarding the application of the 70% rule

ACER has issued a recommendation for the minimum margin available for cross-zonal trade (enclosed). It includes a harmonized approach to monitoring the achievement of the minimum level of available cross-zonal capacity set by Article 16(8) of Regulation (EU) 2019/943. This monitoring is based on the provision of specific data by TSOs. The monitoring reports produced by ACER for the 1st and 2nd half of 2020 have shown that the non-inclusion of 3rd countries very much influences Greece at the calculations. At the ACER report of the 1st half of 2020, Greece and Slovakia are the countries most affected. At the ACER report of the 1ST half of 2020, in case the non-EU counties are not taken into account, IPTO never goes beyond 70%, however with the inclusion of the neighbouring non-EU TSOs for the imports, IPTO goes beyond 70% at the 90% of all cases and 38% for exports respectively. The results are more remarkable at the second half of 2020, where, with the inclusion of 3rd countries, IPTO achieves the 70% rule almost in all cases (87% of cases with the rest 13% mainly due to the period when the line BG-GR was out of operation).

IPTO asked for 2020 and 2021 a derogation from the implementation of the minimum margin available for cross-zonal trade according to Article 16(9) of Regulation 2019/943 for the bidding zone border GR-BG to the SEE CCR. The main reason for this is the absence of consideration of flows of 3rd countries in the capacity calculation and the margin available for cross-zonal trade, and the insufficient potential for remedial actions to guarantee the 70% capacity criterion. The Coordinated Capacity Calculation Methodology does not consider the grid limitations of the neighbouring non-EU countries as well as potential remedial actions within their grid. These neighbouring to Greece non-EU countries are Albania, North Macedonia, Serbia and Turkey.

Cross border exchanges on GR's non-EU borders significantly impact cross border capacity available on GR's EU border and vice versa. ACER recommendation provides that consideration of third (i.e. non-EU member) country flows in capacity calculation and the calculation of the margin available for cross-zonal trade should be possible. IPTO and the rest TSOs of the SEE CCR have tried to make all necessary actions/activities to agree with 3rd countries. However, it is not yet clear that such an agreement will be finalized within 2021, causing the lack of legal conditions to consider the 3rd countries flows during the determination of the binding target set in Article 16(8) of the Regulation 2019/943. The SEE TSOs in autumn 2020 sent an official request to their neighbouring third countries TSOs (OST, MEPSO, TEIAS, EMS), asking them to express their willingness to implement the 70% target on their borders with Greece, Bulgaria and Romania, with the response from these non-EU TSOs to be still pending. Recently, there is an initiative between two RSCs with neighbouring non-EU TSOs, namely SELENE CC and TSCNET, to reach these non-EU TSOs through the non-EU RSC of the region, namely SCC, located in Belgrade. Their goal is to reach an agreement to apply common methodologies approved by the EU, starting from the Capacity Calculation Methodology. We need to note that after the agreements between the EU and non-EU TSOs of the region, the Capacity Calculation Methodology for the SEE CCR needs to be amended to include the participation of the non-EU TSOs and the application of the 70% capacity criterion. Finally, enough time should be given to develop the new methodology and IT implementation by the SEE RSC SELENE CC.

It is expected that during 2022 the second 400 kV line among BG-GR Nea Santa- Maritsa) will partially improve the fulfilment towards the 70% criterion but will not resolve the problem for the reasons mentioned above.