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Department of International & European Studies
MSc in Energy: Strategy, Law and Economics

EU Target Model Implementation towards Sustainability – The Case Study of Greek Power Market

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MSc. Thesis
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Master Thesis

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Abstract

From the 1st of November 2020, the Greek Power Market is re-organized and operates according to the EU Target Model framework. The previous model of the mandatory pool is succeeded by the design and operation of four successive markets. These are the Derivatives Market (DM), which is a financial market and the three spot markets which are the Day-Ahead Market (DAM), the Intra-Day Market (IDM) and the Balancing Market (BM). The present Thesis is an attempt to efficiently organize and interpret the Spot Markets' data and present a holistic overview of the market operation and the dynamics under the transitional period of the first three months under the EU Target Model implementation in the Greek Power Market. The analysis of the present study is performed based on real market data, as published from the Hellenic Transmission System Operator (HTSO), which is the ADMIE/IPTO, the Greek Nominated Energy Market Operator (NEMO), which is the Hellenic Energy Exchange (HEnEX) and the ENTSO-e Transparency Platform. The EU Target Model framework is implemented towards the harmonization of market rules and markets operation, across the European Member States, with the provision of the functioning of a single European-wide energy market, the so-called Internal Energy Market (IEM), where one of the main objectives of the IEM is the increase of sustainability, considering high penetration of Renewable Energy Sources (RES) in a European-wide scale. The remainder of the Thesis is as follows:

- In the first Chapter it is described the value of the implementation of EU Target Model towards sustainability, and more specifically towards the efficient management of increased RES penetration in a European-wide scale. Also, the importance of efficient RES production forecast in combination with an agile market framework as the EU Target Model is underlined.
- In the second Chapter the Greek Spot Power Markets that are operated by the HEnEx are analyzed. These markets refer to Day-Ahead Market and the Intra-Day Market. The Market Clearing Prices (MCP) and the Energy Mix are in-depth analyzed, as well as there is provided a detailed focus on the Cross-Border Trading (CBT) activity.
- The Balancing Market is analyzed thoroughly in the third Chapter. Firstly, it is presented the Balancing Market structure in the Greek Power Market, which comprises of the Balancing Capacity Market, the Real-Time Balancing Market (RTBM) and the Imbalance Settlement Procedure. The data derived from the BM operation are in-depth analyzed, considering the market conditions, balancing energy volumes and prices, as well as a thorough investigation is performed upon the total Balancing Market's cost and its components.
- In the fourth Chapter it is performed an assessment on the liquidity of the Spot Markets according to the total traded volumes of energy and the economic inflows of the domestic producers from these markets.
- The fifth Chapter presents the historical development of the Day-Ahead wholesale prices on a monthly resolution, regarding the Greek Power Market, as well as the European average of the Day-Ahead wholesale prices. Finally, in the same chapter, the weighted wholesale market price is presented and analyzed, considering the three-months transitional period of the EU Target Model implementation.

Keywords: EU Target Model, Day-Ahead Market, Intra-Day Market, Balancing Market, Renewable Energy Sources, Energy Mix, Cross-Border Trading, Market Clearing Price, weighted average market price

Acronyms

ACER	Agency for Cooperation of European Regulators
Act.En.Dn	Downwards Activated Balancing Energy
Act.En.Up	Upwards Activated Balancing Energy
aFRR	automatic Frequency Restoration Reserve
AGC	Automatic Generation Control
AL	Albania
ATC	Available Transfer Capacity
BG	Bulgaria
BM	Balancing Market
BRP	Balancing Responsible Party
BSP	Balancing Service Provider
BSPe	Balancing Servie Providing entity
CAPEX	Capital Expenditure
CRM	Capacity Remuneration Mechanism
DAM	Day-Ahead Market
DAS	Day Ahead Scheduling
DM	Derivatives Market
EBGL	European Balancing Guideline
EC	European Commission
ENTSO-e	European Network Transmission System Operator for Electricity
EU	European Union
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
EV	Electric Vehicle
FCR	Frequency Containment Reserve
FM	Forward Market
HEnEx	Hellenic Energy Exchange
HV LOAD	High Voltage Load
IDM	Intra-Day Market
IMB	Imbalances
IPTO	Independent Power Transmission Operator
ISP	Integrated Scheduling Process
IT	Italy
LIDA	Local Intra-Day Auction
LV LOAD	Low Voltage Load
MCP	Market Clearing Price
mFRR	manual Frequency Restoration Reserve
MK	North Macedonia
MOE	Merit-Order Effect
MP	Market Participant
MTU	Market Time Unit
MV LOAD	Mean Voltage Load
NEMO	Nominated Energy Market Operator
NTC	Net Transfer Capacity
OTC	Over-the-Counter

PCR	Price Coupling of Regions
PTRs	Physical Transmission Rights
PX	Power Exchange
RES	Renewable Energy Sources
RES & GO	Renewable Energy Sources & Guarantees of Origin
RTBM	Real-Time Balancing Market
SDAC	Single Day-Ahead Coupling
SIDC	Single Intra-Day Coupling
TR	Turkey
TSO	Transmission System Operator

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1 Internal Energy Market towards Sustainability

1.1 Introduction

The objectives for the European growth strategy towards a sustainable future are described in the recently published European Green Deal. For the European Union (EU) to achieve its aspirations for climate neutrality and zero net emissions of greenhouse gases by 2050, a set of goals is defined, followed by the corresponding incentives for enabling and supporting the EU member states and the interested stakeholders to take immediate action and contribute to the realization of these goals. Also, it is underlined that the tackling of environmental and climate-related challenges requires mobilizing research and fostering innovation in many sectors of the European society. It is undisputed that the evolution of the energy markets is directly linked with the transformation of EU's economy towards a sustainable future. More specifically, the supplying to the EU final consumers with clean, affordable and secure energy is precisely underlined in the European Green Deal [1].

Focusing on the power sector, the goal for clean energy translates to the increasing in power generation from Renewable Energy Sources (RES) with the most popular being the solar and wind power as they participate with the biggest market shares in the EU energy mixture among other clean technologies and also having the biggest potential for further development [2]. However, solar and wind power generation are characterized by intermittency due to the stochastic nature of the environmental and weather conditions such as the wind speed, solar irradiance, temperature, etc., in the areas of the PV plants and the Wind Farms [3,4]. The unpredictable changes of the injected power in the system due to the intermittency have as a result the creation of generation-load imbalances, which stress the power system flexibility and leads to costly actions from the Transmission System Operator (TSO) in order to preserve the system stability and continuity of supply [5].

The evolution of the power sector considering increased RES participation and smart technologies, needs to be followed by the corresponding developments in the energy market design and operation, in the power system planning, the regulatory and legislative framework and needs to be supported by effective market monitoring and surveillance mechanisms that guarantee the overall efficient market conditions [6]. Increased RES penetration affects the planning and the operation of the system as the traditional centralized architecture of the power system with the large conventional generation plants does not correspond to the needs of a decentralized generation planning with increased renewable energy sources and new entities as aggregators, storage schemes and demand response operators. The wind farms and PV plants are considered as distributed energy sources (DER) and they are often installed far from the consumption centers, so there is the need to efficiently connect the areas where the RES generation is installed with the city centers and the industrial areas where there is demand for energy. Thus, interconnections play a crucial role in assisting the penetration of RES and facilitating the transportation of clean energy to the consumers in a secure and sustainable way [7].

As the penetration of RES in the power system is growing, the challenges for the TSOs also increase and a comprehensive scheme that supports the increased RES participation in the energy market is needed in order to tackle the impact of intermittency in power generation, minimize the supply-demand imbalances, preserve system stability and supply continuity establishing the procurement of clean energy to the final consumers. The handling of the intermittency in RES power generation is assisted by accurate forecasting in order for the TSOs to achieve optimum dispatch of the generation units and better cope with the fluctuations of the net load demand and the corresponding balancing needs of the system. In combination with enhanced forecasting techniques, there is the need for establishing the market mechanisms that allow the efficient scheduling of RES generation at timeframes closer to real time for the implementation of corrective actions after updated forecasting results [8]. The implementation of the EU Target Model framework towards the single European Internal Energy Market (IEM) facilitates the resolution of the aforementioned challenges and assists in the increasing penetration of RES in the EU energy mixture [7].

1.2 Increased RES penetration & Power System Flexibility Challenges

One way to express the flexibility of the power system is to define it as the ability of the system to absorb unexpected changes in the generation-load balance within economic boundaries and reliable operation. More specifically, the system flexibility is "consumed" by the unforeseen changes in the demand side, poor weather forecasting that has as a result the deviation between scheduled and actual RES power generation, and grid infrastructure failures [9]. The increasing penetration of RES in the power system leads to higher flexibility needs in order for the TSO to handle the variability of wind and solar power, dynamically balance the supply and demand and facilitate further increase of renewables' participation in the system. There are various options for enhancing the system flexibility both the short-term and long-term flexibility. The short-term flexibility includes the operational needs and the ancillary services and handles daily, hourly or sub-hourly imbalances. The long-term flexibility considers the system planning in terms of infrastructures and new installations of flexible capacities with modern characteristics. An interesting approach of the flexibility resources in illustrated in Figure 1.1 in an ascending order from low to high-cost solutions. The most cost-effective solution is the improvement in the operations of the market and then follows the "Demand Response" resources, where it mainly refers to a behavioral alternation of the consumption patterns rather than a high-cost investment as it is presented below in this chapter. The other three solutions refer to higher cost interventions. The "Grid Infrastructure" refers mainly to investments in the transmission system with new interconnectors. "Fast Ramping Supply" and the "Energy Storage", refer to investments in additional resources in the system with the corresponding capabilities [8].

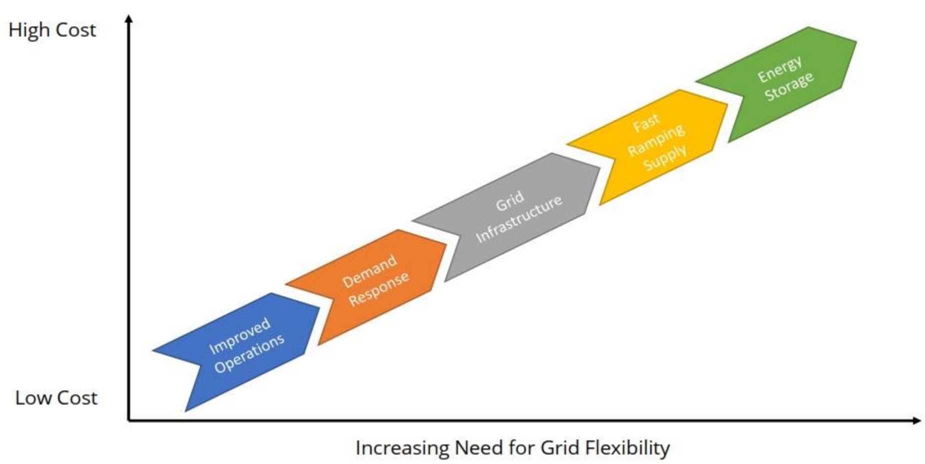


Figure 1.1. Flexibility Source Supply Curve [8]

The operational improvements consider better organization of the market which includes regions coupling for better utilization of operational reserves in a wider area and shorter dispatching market time units in order to capture in a more effective way the abrupt changes of the variable RES generation and the load profiles alternations. It is also underlined that improvements of the forecasting methodologies for more accurate predictions of the renewable generation are considered a valuable flexibility resource as they destress the role of the TSO and fewer back-up reserves are needed for ensuring the reliability of the system [10].

1.2.1 Inertia & Ramping Capabilities

Traditionally, the flexibility of the system was mostly relied on the kinetic energy from the rotating masses (spinning reserves) of the generators in power plants such as the coal-fired plants and Combined Cycle Gas Turbine (CCGT) plants that is referred to as the inertia of the system [11]. The inertia of the system is considered fundamental for the stability of the frequency and it is used as the first response to alleviate the disturbances of the system (primary frequency control) [7]. However, renewables do not contribute to the inertia of the system as they are connected in the system through power electronics. Operational flexibility depends on time scale, considering frequency control, restoration reserves and ramping capabilities. More specifically, the tree main parameters that characterize the flexibility of a unit is the available output range (MW), the ramp rate (MW/min) which shows how quickly is can adjust its output and the energy level continuity (MWh) [12-14]. Thus, resources with fast ramping capabilities such as CCGTs power plants, Combined Heat and Power (CHP) plants and Hydroelectric plants are essential to the increase of the system flexibility by providing fast-ramping response to the abrupt changes in the net load demand for the TSO to dynamically restore the frequency of the system in the nominal value [9].

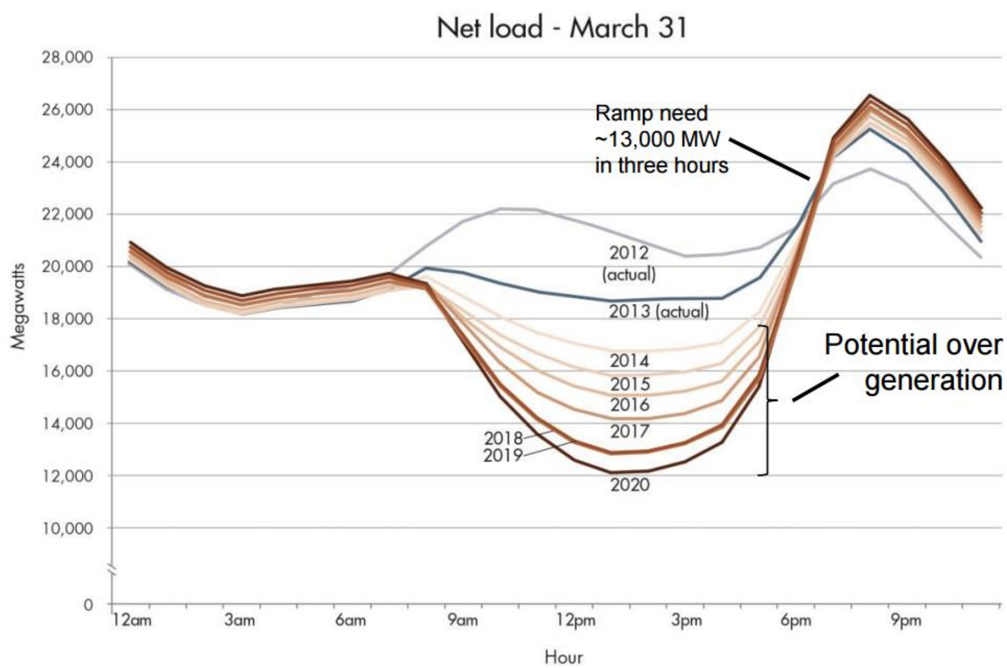


Figure 1.2. Duck-Curve of California from 2012 to 2020 [15]

The increased penetration of photovoltaic generation in the system results higher ramping needs, as depicted from the well-known Duck-Curve graph in Figure 1.2 representing the power system of California, where there is increased penetration of Photovoltaics (PV). As the PV generation increases the thermal plants should reduce their production with fast downward ramping in order to preserve the system stability. Respectively, as the PV generation decreases the other generation resources in the system should provide fast upward ramping. The market also faces a problematic situation during the peak of the PV generation, where the thermal power plants should lower their production or even shut down in order for the TSO to avoid oversupply and preserve system stability, which has a negative impact in the life-cycle of the traditional baseload thermal plants [15]. This also leads to the "missing money" problem in the energy sector where the producers of the thermal power plants cannot recover their capital expenditure (CAPEX) for two main reasons. The first one is the fact that they are obliged to lower or shut down their generation more frequently than used to do in the past and the second is the fact that due to the increased participation of renewable generation in the system the marginal price would be lower, which limits their profit margins for the selling power [16, 17].

1.2.2 Energy Storage Systems (ESS)

The storage of energy is complementary to the installed renewable generation in the power system in terms of stability as it could assist in the mitigation of net load fluctuations. During the time periods where the production of renewable energy is high, storage schemes could be used to absorb the surplus of the produced energy. Accordingly, when the offered renewable generation is lower than expected, the storage schemes could be used to mitigate the resulted imbalances by injecting energy to the system [7]. The Energy Storage Systems (ESS) could act as a complementary solution by reducing also the ramping needs of the system. The combination of renewable generation and ESS enhances the flexibility of the system and creates the potential for enhanced management of intermittences in the generation. The study in [18] shows that ESS connected behind-the-meter with a wind farm results higher revenues for the investment, better handling of wind power errors and increased flexibility through the energy time-shifting capability due to the ESS mitigating the exposure of the investment to imbalance costs.

However, the overall potential of the ESS to mitigate the system imbalances that are caused from the variable renewable generation is rather limited mainly due to the increasing capacities that lead to over-dimensioning of the storage systems. Although, storage might be a cost-efficient and beneficial solution for the prosumers in a local area of the system, it may also cause stress to the TSO regarding the load management where the prosumers may choose to monetize on their surpluses by injecting them in the system, letting the TSO to handle the situation. So, there is the need for defining harmonized rules for the participation of ESS in the market. Furthermore, the need of imports might be reduced when the renewable generation relies on ESS to handle the variability, but due to the amount of required capacity of ESS to support self-sufficiency from renewable generation the effectiveness is comparatively low. Also, the typical patterns of the residential consumption, the wind generation and the photovoltaics generation are all different with each other, which is a challenge for the TSO to efficiently handle and harmonize the different profiles. Therefore, when it comes to ESS participation in the grid, there should be taken into consideration a proper redistribution of their responsibilities and roles in order to efficiently support the imbalances mitigation in the system [19].

1.2.3 Demand Response

The supply side is the most mature to participate in the system balancing process. However, from the demand side, demand response (DR) actions can be a decisive tool to counterbalance the net load fluctuations and contribute to more harmonized and manageable load demand curves, increasing in that way the flexibility of the system. The mechanisms for the demand response are described below through four main categories which are: shape, shift, shed and shimmy [7].

- **Shape** refers to the alternation in the load profile of the consumer which is linked to behavioral responses as derive from the incentive for better power prices.
- **Shift** corresponds to the choice of the consumer for energy demand in time periods where there is high renewable generation instead of times where there is already high demand and lower renewable power injection.
- **Shed** refers to the ability of the consumer to interrupt its load in emergency conditions. In the corresponding literature it is often referred to as load shedding.
- **Shimmy** corresponds to the flexibility from the demand side to gradually increase or decrease the load in order to alleviate short-term ramps and disturbances in the system.

The participation of demand response resources in all wholesale markets (Forward Market, Day-Ahead, Intra-Day and Balancing) in the same way as a conventional generator, will increase the system efficiency and decrease the system price to its real market value, setting a robust market signal for the cost of energy. The core concept of the demand response mechanism is to consume the surplus of the produced energy in the system and reduce the demand when there is a scarcity [20]. So, demand response can contribute to the enhancement of the system reliability considering peak-load valley characteristics and variable renewable generation [21]. Also, the economic benefits from the wind generation and the reduction of imbalance costs due to the fluctuating output, can be further improved when the wind power producers execute energy trades with demand response customers. The wind power producer can sell energy at off-peak periods to demand response customers and leverage from better pricing. Furthermore, the energy trading between a wind energy producer and DR customers facilitates in handling the economic impact of the uncertainties in both sides from the imbalance costs and support the minimization of the curtailed wind generation [22]. It is also important to mention that Electric Vehicles (EVs) can act either as ESS or DR providers. EVs are considered flexible loads that can provide ancillary services to the power grid as Demand Response resources when there is a surplus of RES generation or connect to the grid and serve as ESS when there is a scarcity [23].

1.2.4 Interconnections

Adequate transmission capacity also increases the flexibility of the system as it allows the trading of power within a wider area, which means access to a more options for the utilization of balancing resources. With sufficient cross-border capacities the TSO increases the necessary flexibility for meeting short-term balancing needs through power trading with neighboring TSOs [8]. More specifically, the interconnection between neighboring countries increases the reserve capacities and decrease the variability of solar and wind power since the generation is distributed across a wider area [9]. In that way TSOs mitigate the impact of the forecast errors in generation and consumption, enhance their role in providing security to the system and minimize the cost of energy as there is a decreased need of occupying domestic balancing capacity reserves. Interconnectors are a key component for the European energy strategy since these infrastructures facilitate in a cost-effective manner the growing integration of RES generation in the power system, increase power trading and assist power flows from regions with lower prices to regions with higher prices, resulting a harmonized European price, which is defined by the competition in the liberalized energy markets and constitutes a robust market signal for the operation and development of the power system [7].

1.2.5 Market Framework

Among the aforementioned options for supporting the system flexibility needs towards the higher penetration of renewable energy, one of the most cost-efficient and decisive is the structure and operation of the market. The design of the market with timeframes of participation for the market players closer to real time, assists in a major way to the flexibility of the system, as the needs for further covering the imbalances are minimized. More specifically, the enhanced forecasting of the load demand and variable generation in combination with the ability of short-term scheduling, results less flexibility needs of the system [23]. The reference model of market structure for a unified European energy market (a.k.a. EU Target Model), mitigates the increasing needs of flexibility due to higher RES penetration with the provision of four successive markets with different scheduling timeframes (Forward, Day-Ahead, Intra-Day and Real-Time Balancing) [24]. The balancing market as it is described in the following section is the most important market for the system stability as it is the last resort for the physical balancing of the actual demand and supply of the system in real time, including ancillary services and emerging roles as aggregators [25].

1.3 Internal Energy Market

The cornerstone for the implementation of the Internal Energy Market (IEM) is the EU Third Legislative package that describes the directives for the liberalization of the European energy sector. The EU Target Model is a benchmarking model that derives from the Third Legislative Package and describes the process under which the harmonization of the energy market rules of the EU member states can be achieved towards a single European energy market. The Agency for the Cooperation of Energy Regulators (ACER) and the European Network Transmission Systems Operators for electricity (ENTSO-e) are also established by the Third Energy Package and jointly with the European Commission (EC), create detailed network access rules and technical codes, and ensure the coordination of grid operation through the exchange of operational information and the development of common safety and emergency standards and procedures. ENTSO-e is also responsible for drafting a 10-year network investment plan every two years, which is then in turn reviewed by ACER [26]. The IEM will contribute in a European-wide reduction of prices through the increasing competition, the reduction of market power concentration and the creation of additional market liquidity. Also, under the IEM it is provisioned the unproblematic flow of power from areas with lower prices to areas with higher prices, the minimization of back-up generation needs to support the increased penetration of RES in the European system and the enhancement of the energy supply security through cross-border balancing mechanisms, which increase the flexibility of the power system and lowers the prices for the final consumers [27].

1.3.1 EU Target Model Markets

The framework of the EU Target model includes four successive wholesale markets with different scheduling timeframes. The Forward Market (FM), the Day-Ahead Market (DAM), the Intra-Day Market (IDM) and the Balancing and Ancillary Services Market (BASM). The operation of the DAM and IDM is the responsibility of the Nominated Energy Market Operator (NEMO), whereas the operation of the Balancing Market is the responsibility of the Transmission System Operator (TSO). The energy transactions can be delivered either in the form of bilateral agreements via Over-The-Counter (OTC) contracts or through an organized power exchange (PX) where there is access to various standardized energy products for the market participants [24].

The FM includes products of energy derivatives as tools for hedging against long-term price changes according to price development forecasts [28]. The instruments for the forward market can be either standardized future contracts which are negotiated via power exchanges (PX) or forward agreements that refer to OTC contracts and are underlined to a specified price and quantity on a future delivery date. In the DAM is auctioned the remaining amount of energy that is not reserved from the FM obligations. The transactions of energy in the DAM for delivery day D are auctioned in day D-1 and the participation for the energy producers is mandatory. At the time of gate closure of the DAM the scheduled generation should be equal to the forecasted demand also considering the cross-zonal trading of energy. Through the participation in DAM the Market Participants (MPs) reduce their exposure to volatile spot prices as the timeframe gets closer to real-time delivery of energy. In the IDM the market participants can correct their trading position considering evolving market and system conditions and mitigate their exposure to deviation charges compared to their offers in the DAM. The deviations between the scheduled position and the actual energy needs of the system can be derived either from the poor forecasting of load consumption and renewable generation, unforeseen changes in the demand side or even outages in system lines and power plants. The auctions in the IDM start from the gate closure time of the DAM until the day of delivery (D) and the participation is optional for all market participants. There are three different phases for the implementation of the IDM. The first phase refers to the Local Intra-Day Auctions (LIDAs), where the market participants place their bids and offers considering a single bidding zone (isolated auctioning). The second phase refers to the Complementary Regional Intra-Day Auctions (CRIDAs), where there is market coupling between two or more bidding zones and the market participants consider a wider region with more resources for their market participation strategy in a peripheral level. The final phase implements the XBID project, which refers to cross-zonal continues Intra-Day Auctions, where the matching of bids and offers is executed in real-time [7, 29].

The integration of national energy markets into a single European energy market is a gradual procedure and is implemented with the market coupling [7]. Market coupling is the integration of two bidding zones into one common market with harmonized market rules implemented by cross-zonal capacity allocation mechanisms. In order to establish a real market coupling it is fundamental to eliminate power flow bottlenecks in order to ensure the unconstrained transportation of energy at any possible time of need from a neighboring region. The market coupling considers implicit auctioning of transmission capacities in the sale price of energy for the participants in the coupled markets. Therefore, market coupling transforms the wholesale power markets by introducing the necessity for tackling the transmission capacity congestion and ensure the unproblematic cross-zonal trade of energy. The Capacity Allocation and Congestion Management (CACM) and the Forward Capacity Allocation (FCA) network codes as introduced by the ENTSO-e ensure that the implementation of the IEM is performed under the optimum transferring capacity allocation with the minimum bottlenecks for the interconnections and assist in the freely cross-zonal transportation of energy at any time [30-32]. CACM and FCA are the cornerstones for the implementation of the Single Day-Ahead Coupling (SDAC) and the Single Intra-Day Coupling (SIDC). The SDAC refers to the coordination of auctions for setting a harmonized European price of electricity considering cross-zonal capacity allocation and simultaneous matching of orders of the Day-Ahead Markets per bidding zone. The mechanism which assists in the establishment of a single pan-European price is the Price Coupling of Regions (PCR) project. The PCR is implemented by the Power Exchanges through a common price coupling algorithm called EUPHEMIA (acronym of Pan-European Hybrid Electricity Market Integration Algorithm) and ensures transparency for the net positions of the market participants considering day-ahead transmission capacities and electricity prices across Europe [33]. The SIDC refers to the continuous collection and matching of orders from the wholesale market participants per bidding zone, with the obligation of physical delivery on day D. The SIDC considers implicit cross-zonal capacity allocation and follows the day-ahead market allocation process. The goal of the SIDC is to provide continuous cross-border trading of power through the XBID project, towards the optimum participation of resources considering a European-wide power market maximizing the overall social welfare [7].

1.3.2 Balancing Market

The Balancing Market is the last of the four markets of the EU Target Model framework, following the Forward Market where futures and forward energy contracts are negotiated, the Single Day-Ahead Market and the Single Intra-Day Market as illustrated also in Figure 1.3. The balancing process refers to the role of the TSOs to manage the physical equilibrium between injections and withdrawals on the grid (generation and consumption balance). The power system balance is estimated for multiple timeframes from years ahead to real time and the role of TSOs becomes more critical when the timeframe gets closer to and in real time. The first step of the TSOs for managing possible imbalances takes plays ahead of time and ensures that there is the necessary reserved capacity in the system in case of an unforeseen imbalance. The second step takes place in real time and ensures the availability of balancing energy through the activation of the balancing reserves that can provide ancillary services to the grid and maintain the balance in the power system [24].

The European Guideline for the Electricity Balancing (EBGL) introduces the corresponding mechanisms that assist in the power system balance restoration as well as it defines the roles for the participants that operate in the Balancing Market [34]. The structure of the BM consists of the Balancing Capacity Market, the Balancing Energy Market and the Imbalances Settlement Procedure. In the scope of the Balancing Capacity Market, it is ensured before real-time that the necessary resources will be available to provide the necessary reserves for contributing to the balance restoration of the power system. The real-time balancing of the system takes place in the Balancing Energy Market, where the reserves form the Balancing Capacity Market are activated, providing the flexibility to the system through upwards and/or downwards activation of ancillary services for the restoration of system frequency at the steady-state value. At the last stage of the balancing market structure, all the imbalances are fairly remunerated for the balancing service providers and awarded for the responsible entities that deviate their scheduled capacity from the actual energy that was metered in the system [24, 35].

A key element for the design of the balancing market is making all parties financially responsible for meeting their own balancing requirements. Therefore, all parties will have the incentives to ensure that their participation in the energy market minimizes the balancing needs of the whole system. The encouragement of the market participants and especially of the RES producers to balance their own portfolio considering financial incentives, decreases the volume of actions that the TSOs need to take in order to ensure the reliability of the system operation [36]. Therefore, TSOs' role remains to deal with imbalances which cannot be avoided for the grid due to RES generation forecast errors, which will be minimized after the allocation of responsibility to RES producers, errors in load demand predictions, plant and infrastructure failures or any other unforeseen event. On the opposite side, if RES participants did not have the responsibility to balance their own portfolio, there would be needed increased capacity reserves as the TSO would be exposed to high fluctuations of the net load demand considering increased RES penetration and ultimately that would increase the cost of energy and decrease system efficiency. Under the prism of the Balancing Market the market participants are distinguished in two main categories according to their involvement in the balancing process. As describe below, these are the Balancing Service Providers (BSP) and the Balance Responsible Parties (BRP) [35, 37].

Balancing Service Providers (BSP) are the entities in the market that offer ancillary services (FCR, aFRR, mFRR, RR) to the TSO for the balancing needs of the system. BSPs participate in the balancing capacity market by committing part of their portfolio's resources for the balancing needs of the system and they activate their scheduled reserves when it is requested from the TSO by delivering energy through the Real-Time Balancing Market (RTBM). There are various technologies that can participate in the balancing market as BSPs, counting for the conventional power plants (coal fired and CCGTs) and the Hydro plants to demand response providers, storage schemes and RES producers.

Balance Responsible Parties (BRP) are the entities that have the obligation to maintain the power balance of the system through their responsibility to keep their actual position in the market equal to their scheduled position regarding their energy needs. As BRPs are considered all market participants from consumers and suppliers to different kinds of power generators and aggregators. BRPs are subjected to imbalance charges according to the amount of imbalance that they cause to the grid, so they face the financial incentive to have their portfolio balanced in every scheduled time unit within the day of delivery.

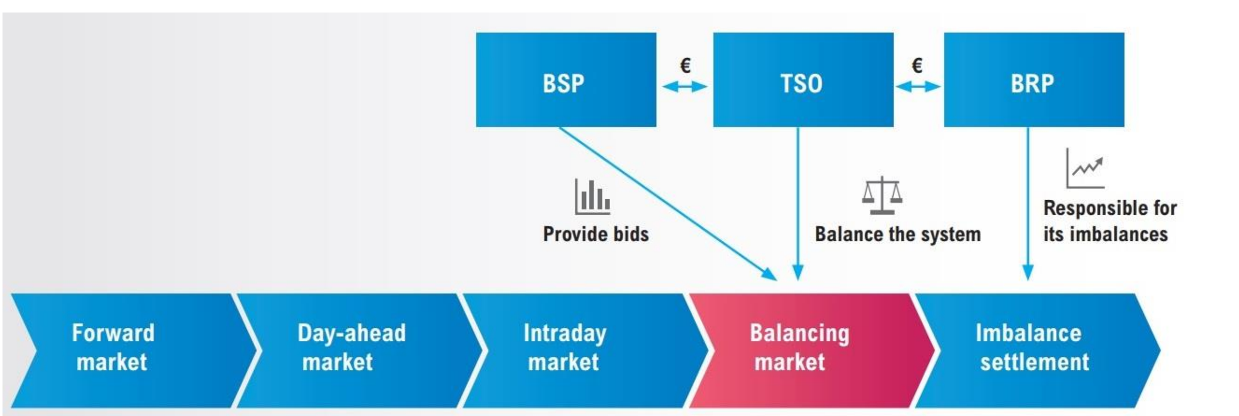


Figure 1.3. Target Model Markets sequence [37]

Regarding the dispatch schemes of the balancing markets there are two main high-level models that are followed across the European countries, which are the Self-Dispatch and the Central Dispatch models. In the self-Dispatch model, the instructions for the balancing needs of the system are acquired from the TSO in a portfolio-based level. The balancing responsible parties perform self-scheduling of their resources based on their own economic criteria, considering generation and technical constraints of the system. On the other hand, the Central Dispatch model relies on the TSO to perform the dispatching of the system components on a unit-based level to meet the balancing needs of the system, considering the overall operational needs of the system simultaneously to cost-efficient central scheduling. Regarding the Central Dispatch model, the balancing procedure is divided in two phases. The Integrated Scheduling Process (ISP) and the Real-Time Balancing Market (RTBM) [38].

The ISP is an evolution of the unit commitment model, which additionally considers the allocation of various types of Reserve Capacity eligible for balancing resources, the procurement of Balancing energy (upwards and/or downwards), congestion management and the market schedule from the previous markets (DAM/IDM). The ISP process is essentially the co-optimization of the market parameters considering the system operational constraints and it is based on a Mixed-Integer Linear Programming (MILP) model. The execution of the ISP is a repetitive process for every scheduled market time unit which begins successively from a Day-Ahead scheduling phase to Intra-Day executions with respect to the IDM scheduling sessions. The length of the market time units is essential to be as short as possible in order for the market participants and the TSO to capture in the scheduling results the load volatility, the renewable generation variability and the most accurate system requirements based on updated forecasting results of load demand and RES generation. It should be noted that the TSO have the right and the responsibility to execute additional "on-demand" ISPs in case of a major event that takes place during day D or even in the afternoon of D-1 for better adjustment of the market results, preserving the optimum dispatch of the resources under the new conditions [24].

The scheduled Balancing Capacity in the ISP is activated from the TSO in the Real-Time Balancing Market (RTBM) through the delivery of the Balancing Energy from the BSPs. The BSPs are obliged to submit their offers for Balancing Energy according to their maximum availability in order for the TSO to have more options during the real-time balancing process. Upwards Balancing Energy refers to the production of more energy from the generators or the reduction of the energy consumption from DR resources, whereas downwards Balancing Energy refers to the reduction of the energy production from generators or the increase of the energy consumption from DR resources to restore the system balance. During the RTBM the BSPs can update their offers only with better prices compared to their respective offers in the ISP. Improved prices mean lower bidding prices for the upwards activated balancing energy and higher offered prices for the downwards activated balancing energy, towards the maximization of the total social welfare of the market. The Balancing Energy corresponds to the restoration of the system frequency in acceptable levels after the occurrence of an imbalance through the activation of ancillary services [34, 35].

1.3.2.1 Frequency Control Processes

The frequency control of the system in case of a disturbance that caused from an unpredicted physical imbalance between generation and demand is performed by ancillary services, which are activated gradually in certain timeframes from the occurrence of the imbalance. The hierarchy of the Load-

Frequency control process is illustrated in Figure 1.4 where the synchronous area refers to the integrated area of responsibility for the TSO to preserve the frequency at a steady state value, whereas, as defined by Article 3(12) of the System Operation (SO) Regulation*, "the Load Frequency Control (LFC) area corresponds to a part of a synchronous area or an entire synchronous area, physically demarcated by points of measurement at interconnectors or other LFC areas, operated by one or more TSOs fulfilling the obligations of load-frequency control"* [45].

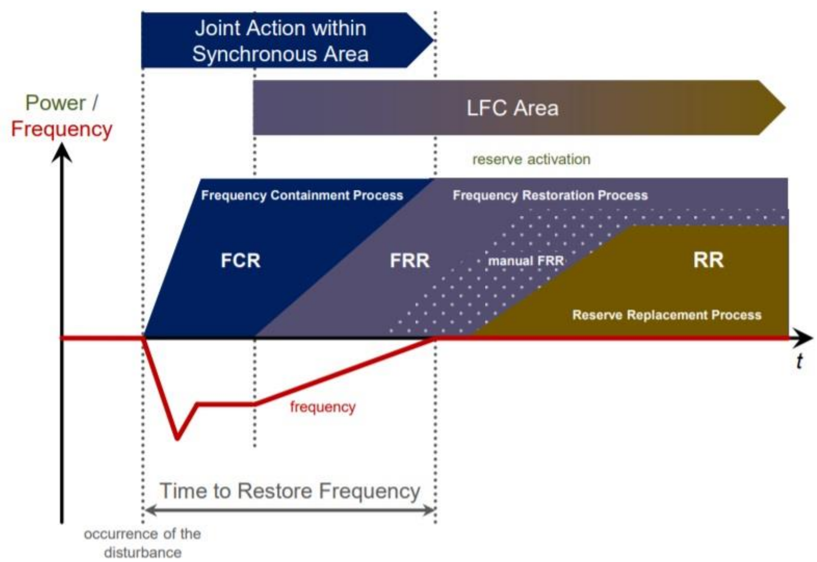


Figure 1.4. Dynamic hierarchy of LFC processes [45]

The primary response takes place usually within 15 to 30 seconds (frequency restoration from 50% to 100% respectively) and it is performed by the Frequency Containment Reserves (FCR). It is an automated decentralized process of reserves activation in order to restore the frequency to a steady-state value in a very short time after the imbalance occurrence considering the whole synchronous area [25, 37, 39].

The secondary frequency control is implemented by the Frequency Restoration Reserves (FRR) in order to restore the power balance to the scheduled value and the system frequency within acceptable limits. It is a centralized process activated by the TSO with serving time intervals from 30 seconds up to 15 minutes from the imbalance occurrence and is triggered by the disturbed LFC area. FRRs are further distinguished into automated Frequency Restoration Reserves (aFRR) and manual Frequency Restoration Reserves (mFRR) and replace the activation of the FCR. The activation of the aFRR is performed through the Automatic Generation Control (AGC) which is a centralized process that automatically adjusts the power output of the corresponding generation units, whereas the mFRR is activated manually considering the economic dispatch of the balancing service providers' offers in the balancing market [25, 37, 39].

The tertiary frequency control relies on the Replacement Reserves (RR) which is also a centralized process activated by the TSO. The activation of the RR is triggered by the disturbed LFC area and preserves frequency stability for time intervals from 15 minutes to hours after the occurrence of the imbalance. The

RRs are activated to restore or support the FRRs to be prepared for possible additional imbalances in the system [25, 37, 39].

1.3.2.2 Imbalance settlement Procedure

The Imbalance Settlement Procedure is an ex-post procedure, where the BRPs are awarded with imbalance charges and the BSPs are remunerated for the reservation of part of their portfolio resources in the Balancing Capacity Market and the Ancillary Services (AS) they provided during the Balancing Market both for the reserved capacity and the activated balancing energy. Traditionally, the reserve costs where distributed pro-rata to all market participants in the notion that the Capacity Reserves serve the system stability which is beneficial for the system as a whole [24]. However, the Target Model provisions are aimed to allocate the cost of imbalances according to the impact of every market participant. For example, RES producers cause more imbalances than other participants, due to the intermittency in their production, that consequently increase the balancing needs of the system. So, it is more efficient to allocate the costs of the physical imbalances according to the corresponding responsible parties that cause these imbalances [34].

The length of the Settlement Period is also a crucial variable in the Imbalance Settlement Procedure as it should form the representative signals (financial incentives) to the market participants to be efficiently balanced. The logic is that as approaching to real-time the balancing charges should be higher. The time-period should be 30 minutes or shorter, with the trend on the European markets to focusing on a 15-minutes settlement period. Thus, the BRPs that are frequently prone to cause imbalances in the system will be levied to higher charges and they will have the incentive for more efficient short-term scheduling of their resources, relying on robust short-term forecasting models [24, 36].

Regarding the remuneration of the procured Balancing Energy there are two possible options, which are the pay-as-bid option and the marginal pricing. In the pay-as-bid option the BSPs receive the price of their own offers if their resources are activated by the TSO. The marginal pricing option reflects the cost of the balancing energy as resulted from the merit order procedure and this is the remuneration price for all the participants with balancing resources [40].

1.3.2.3 Towards a harmonized cross-zonal Balancing Market

The products of the BSPs should have robust technical requirements in order to be able to efficiently follow the abrupt changes in the increased variable renewable generation. Also, towards the harmonization of the European energy markets these products shall be standardized and characterized at least from the following parameters as show in Figure 1.5, which are preparation period, ramping period, full activation time, minimum and maximum quantity, minimum and maximum duration, validity period and the mode of activation [37].

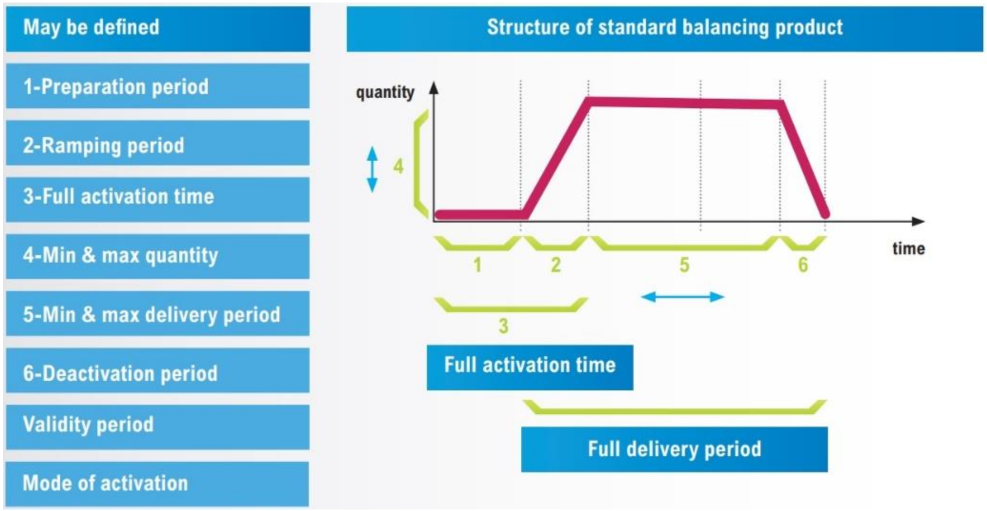


Figure 1.5. Characteristics of a balancing product [37]

Furthermore, in the context of the pan-European energy market ENTSO-e has provisioned the implementation of the corresponding platforms of each kind of ancillary services (FCR, aFRR, mFRR, RR) for the efficient coordination and transparency of the cross-zonal energy balancing procedure [37]. Another balancing process that derives from the transition of the European energy sector towards a single Internal Energy Market is the Imbalance Netting (IN). The Imbalance Netting process is designed to reduce the amount of simultaneous and counteracting aFRR activation of different participating and adjacent LFC areas via imbalance netting power exchange. It is agreed between adjacent TSOs in order to avoid simultaneous activation of aFRR in opposite directions. An illustration of the IN process is presented in Figure 1.6 and the International Grid Control Cooperation (IGCC) is provisioned to be the European Platform for the imbalance netting process (IN-Platform) [41].

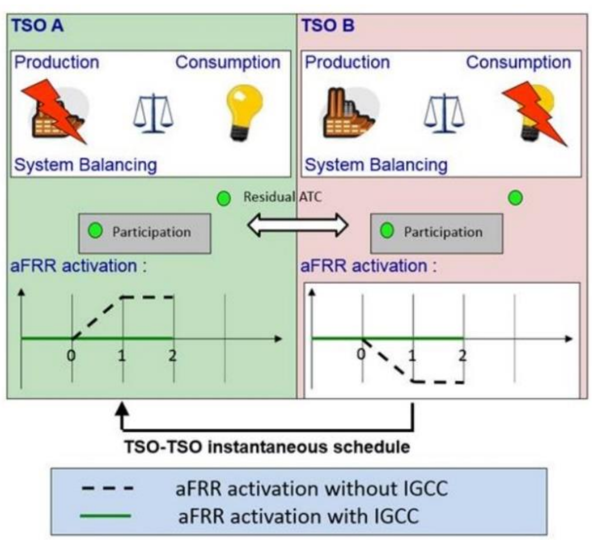


Figure 1.6. Imbalance Netting in IGCC [41]

Regarding the harmonization of mFRR products, the ENTSO-e has provisioned the implementation of the Manually Activated Reserves Initiative (MARI) platform [42]. The Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO) is the project for coordination of the aFRR products between TSOs [43] and for the harmonized participation of Replacement Reserves (RR) products the ENTSO-e has designed the Trans-European Replacement Reserves Exchange (TERRE) platform [44]. Ultimately, for each platform and respective timeframe of every product (positive or negative imbalance) of the participating TSOs, the marginal price of each service will be established regarding a Common Merit Order List (CMOL) as shown in Figure 1.7 below.

Figure 1.7. Common Merit Order List for balancing energy bids [37]

1.4 Efficient RES Participation towards the EU Target Model Markets

The intermittent renewable sources as wind and solar power are non-dispatchable units and participate in the power markets based on their forecast of power output, as opposed to the other energy sources like nuclear, coal-fired plants, CCGTs etc., that are considered dispatchable and they participate considering their controlled power output. So, the accuracy of the renewable energy production forecasting is decisive for their efficient participation in the energy market competition without supportive governmental payment schemes [46, 47]. Traditionally, the growth of RES has been supported by governmental subsidies (*State-Aid support schemes*) as the feed-in tariffs and feed-in premium schemes. However, these support schemes create the Merit-Order Effect (MOE) which leads to the distortion of the competition and hinders the formation of the right market signals for future investments in the field. The liberalization of the energy markets regarding the renewable generation is in the right direction since RES producers improve their profitability according to their participation strategy through the evolving market competition which leads to the formation of spot prices representative to the actual cost of energy [17, 48].

The higher penetration of the variable RES generation increases the system balancing requirements and decreases the short-term availability of traditional balancing resources leading to higher cost of energy and decreased efficiency of the power systems. Thus, the integration of RES should be as cost-efficient as possible in order to assist in restraining the energy cost at affordable levels for the final consumers. So, there is the need to rely on market mechanisms and tools to minimize the volume and cost of short-term imbalances and assist in the greater integration of RES in the grid [55]. The combination between an efficient market structure with scheduling time units close to real time and the enhancement of the forecasting techniques, minimize the balancing needs of the power system in an efficient manner and destress the role of TSOs in case of imbalance occurrence. It is noted that a physical imbalance between generation and demand mainly derives from the transactions in the wholesale markets (DAM, IDM). In DAM and IDM, the market participants place their bids and offers in order to trade a certain amount of energy ahead of time and the scheduling from the TSO is executed based on these declarations. Due to forecast errors in renewable generation and load demand the actual energy that will be needed to meet the system equilibrium may deviated from the scheduled one, creating an occurrence of imbalance that is handled in the Balancing Market. Thus, the maturity of the market participants is fundamental for the efficiency of the system operation, in terms of accuracy in the prediction models that are used for their responsible participation in the market.

Accurate forecasting is important in order to tackle the rising Intra-Day uncertainties of the market participants due to the variable generation in the system. The profitability of the market participants is highly related to the accuracy of their forecasting capabilities towards more efficiently hedging of their portfolio in the long-term and mitigating the imbalance charges in the short-term. Shor-term trading is improving the market efficiency through the mitigation of absolute system imbalances. In addition, the appropriate financial incentives can contribute to the responsibility of the wind and solar producers to keep their portfolios balanced in the Intra-Day markets [49].

The accuracy in renewable generation forecasting gains increasing market value especially in the liberalized markets for the participants as the RES producers, aggregators, traders and suppliers. In a well-structured energy market, the forecasting accuracy is the key element for the strategic participation and the differentiation of the market players which ultimately leads to higher competition. Robust forecasting techniques have a great impact on the profitability of the RES producers as forecast errors in renewable generation create imbalances in the system which in turn expose the balancing responsible parties to imbalance charges. Consequently, lower balancing costs of the market participants due to better handling of the RES intermittency result lower spot prices for the consumers which is a pillar of the EU target model framework as well. More specifically, the imbalances due to wind and solar forecast errors increase the cost of energy as the resulted spot prices are influenced by the imbalance costs [50], so an increase in the forecasting accuracy of the variable generation will have as a result lower imbalances and subsequently lower spot prices.

The importance of accurate forecasting of the variable RES generation is not only underlined in the corresponding literature under a theoretical prism but it is also answered in practice directly from the participants in the real energy market. The issues that derive from the uncertainty in the renewable generation can efficiently be mitigated through the advancements in the forecasting methodologies that will add value to the market participants, as this will facilitate more accurate bidding strategies that minimize the exposure to imbalance charges, and also enhance the role of the TSO to stabilize the system in terms of supply-generation balance. The amount of installed renewable generation is strongly related to the number and size of the imbalances in the system and statistically the wind generation is mainly responsible for the needs for balancing energy in the system [51].

An emerging role with gradually increasing importance in the balancing market is the role of aggregator, both in the demand and generation side. The aggregator is an entity that simultaneously represents a portfolio of assets aiming for the maximization of the financial remuneration of its units through the optimization of the power scheduling and the participation in the ancillary services market [52]. Alternatively, the aggregation refers to a common representation and bidding strategy of a portfolio of generation units and/or consumption points, where its goal is to build up sufficient capacity of flexibility for better handling of the uncertainties of their portfolio resources in the balancing market. The aggregation of Distributed Energy Sources (DER) in a single entity results increased social welfare for the RTBM and facilitates the increased participation of renewable generation [53]. The maximization of the profits and the minimization of the associated risk for the wind generators is enhanced when the offer/bidding strategy for the energy trading incorporates in the same aggregator demand flexibility resources [54]. In the current literature the role of aggregator is commonly analyzed through the paradigm of the Virtual Power Plant (VPP). In [52] it is shown that the combination of generators and ESS units in a flexible unit portfolio operated by an aggregator, has substantial net-operating revenues that benefits all portfolio assets.

Although it is not a generally accepted solution for the public, the curtailment of RES generation constitutes an option for flexibility in the system and gives the capability to the RES producer for offering ancillary services to the grid. Furthermore, RES generation curtailment might be forced for transmission or operational constraints, where there are no other flexibility assets as power plants with ramping capabilities or DR providers [56]. Thus, the common management of these assets under the same aggregator, increases the flexibility of the system and the profitability of the aggregator through the implementation of optimum participation strategy in the market [9,23]. RES aggregators are designed to handle different renewable technologies and can serve as a significant source of flexibility in serving the grid through balancing mechanisms. The RES aggregation also facilitates the market position of smaller units that otherwise would find it difficult to efficiently participate in the market [24]. Furthermore, through the diversification of the renewable technologies in the portfolio of the aggregator and the spatial distribution of RES, enhance the effectiveness of the bidding strategy and mitigate the impact of the intermittency of RES generation in the power system. By reducing the uncertainty on the renewable generation through accurate forecasting, RES producers become more mature and reduce their risk in signing bilateral OTC contracts for hedging and risk management reasons aiming for the optimization of their assets. Additionally, the combined representation under the same aggregator of RES producers with spatial diversification increases even more the potential revenues, as the aggregator mitigates the uncertainty of the RES production in a portfolio level. Thus, the participation for a RES producer in the power markets through an aggregator is more efficient and the risk is minimized.

2 Analysis of HEnEx Spot Markets (DAM & IDM)

The tasks related to the Day-Ahead Market (DAM) and Intra-Day Market (IDM) are operated by the Greek Nominated Electricity Market Operator (NEMO) which is the Hellenic Energy Exchange (HEnEx). The participation in DAM is obligatory for the producers and optional for the rest of the Market Participants (MPs), whereas the participation in IDM is optional for all Market Participants. For both markets, the Market Time Unit (MTU) refers to the hourly duration of the traded products and the trading platform for the operation of DAM and IDM is the Energy Trading Spot Market System (ETSS).

The DAM refers to buy and sell trades of electricity with an obligation of physical delivery, which are concluded by submitting respective orders at each calendar day D-1 for the physical delivery for each MTU of Delivery Day D. The types of orders that can be submitted from the MPs for the DAM products are the Hourly Hybrid Orders, the Block Orders, the Linked Block Orders and the Exclusive Group of Block Orders. Furthermore, the Priority Price-Taking (PPT) Orders are provisioned, that are submitted by the TSO and the RES & GO Operator. The TSO can submit PPT Orders for the scheduled production of Generation and/or RES Units in Commissioning or Testing Operation, for the Mandatory Hydro Injection and the forecasted volumes of the Transmission System Losses. The RES & GO Operator can submit PPT Orders for the forecasted generation of RES under the Feed-in Tariff and Feed-In Premium regime and the declarations of the Dispatchable high efficiency CHP Units. Also, the PPT orders are used for the participation in DAM of quantities that were settled in the Forward Market (FW) and have the obligation of physical delivery on Delivery Day D [57].

The IDM refers to buy and sell trades of electricity with an obligation of physical delivery by submitting respective orders at each calendar day D-1 and/or each calendar day D, for Local Intra-Day Auctions (LIDAs) or Complementary Regional Intra-Day Auctions (CRIDAs), or traded in the Continuous IDM (XBID project) for each MTU of Delivery Day D. The implementation of IDM is distinguished in three phases. The first phase refers to the implementation of LIDAs, where the objective of the respective algorithm is the maximization of the total social welfare based on submitted trades within the Bidding Zone of Greece only. The second phase refers to the implementation of CRIDAs, where the objective of the respective algorithm is the maximization of the total social welfare based on submitted trades not only within the Bidding Zone of Greece but considering the submitted trades from additional bidding zones in a Regional level. The third phase refers to the Continuous Intra-Day trading of electricity products across coupled bidding zones and corresponds to the realization of the Single Intra-Day Market (SIDM).

In the scope of the time period under study in the Greek Power System the Intra-Day Market operates according to the first phase, which refers to the execution of three LIDAs per Delivery Day D and the MPs can participate in the market only by submitting one type of orders, the Hybrid Orders. The first two LIDAs (LIDA1, LIDA2) refer to all 24 MTUs of Delivery Day D, whereas LIDA3 refers to the last 12 MTUs of Delivery Day D. In the first phase of the IDM, the eligible participants are the domestic producers and the domestic load representatives. Traders are not allowed to participate in the IDM for the period under study.

2.1 Market Clearing Price Statistics

The Market Clearing Price (MCP) is the most robust signal in the wholesale markets that corresponds to the market conditions. In the present section the MCP of DAM and IDM data are analyzed [58] for the first three months of EU Target Model implementation in the Greek Power Market (i.e., November 2020, December 2020, January 2021). In the first section of the present sub-chapter, the basic statistics of the MCP development are calculated and presented, for DAM and the three LIDAs of IDM, with daily and monthly resolution. In the second section of the present sub-chapter, it is performed the calculation of the standard indices for the Power Futures of the European Energy Exchange (eex) based on the Greek DAM MCP results for the period under study (01.11.2020-31.01.2021).

The following equations are used for the respective calculations both for DAM and IDM MCP results. The basic statistics of the daily analysis of MCP are calculated based on equations $(2.1) - (2.4)$ for the daily average, minimum, maximum and spread of the MCP results, respectively.

$$MCP_{average}^{day} = \frac{1}{24} \sum_{mtu=1}^{24} MCP_{mtu} \tag{2.1}$$

$$MCP_{min}^{day} = \min\left(MCP_1, MCP_2, \dots, MCP_{24}\right) \tag{2.2}$$

$$MCP_{max}^{day} = \max\ \left(MCP_1, MCP_2, \dots, MCP_{24}\right) \tag{2.3}$$

$$MCP_{spread}^{day} = MCP_{max}^{day} - MCP_{min}^{day} \tag{2.4}$$

Accordingly, the calculations for the basic monthly statistics are performed based on equations $(2.5) - (2.9)$, for the monthly average, minimum, maximum, spread and average daily spread of month, of the MCP results respectively. The dom parameter represents the “days of month” under study and equals to 30 for November and 31 for December and January.

$$MCP_{average}^{month} = \frac{1}{dom} \sum_{day=1}^{dom} MCP_{average}^{day} \tag{2.5}$$

$$MCP_{min}^{month} = \min\left(MCP_{average}^{1}, MCP_{average}^{2}, \dots, MCP_{average}^{dom}\right) \tag{2.6}$$

$$MCP_{max}^{month} = \max\left(MCP_{average}^{1}, MCP_{average}^{2}, \dots, MCP_{average}^{dom}\right) \tag{2.7}$$

$$MCP_{spread}^{month} = MCP_{max}^{month} - MCP_{min}^{month} \tag{2.8}$$

$$MCP_{average\ spread}^{month} = \frac{1}{dom} \sum_{day=1}^{dom} MCP_{spread}^{day} \tag{2.9}$$

The application of equations $(2.10) - (2.12)$ have as a result the estimation of the curves of the representative days per month. More specifically, three different curves are formulated for each month that consider all the days of months, the weekdays within the respective month and the non-weekdays within the respective month. The count of weekdays refers to the days from Monday to Friday, whereas the count of non-weekdays refers to the days of weekend (i.e., Saturday & Sunday).

$$MCP_{all}^{mtu,month} = \frac{1}{dom} \sum_{day=1}^{dom} MCP_{day}^{mtu} \tag{2.10}$$

$$MCP_{weekday}^{mtu,month} = \frac{1}{count\_of\_weekdays} \sum_{day=1}^{count\_of\_weekdays} MCP_{day}^{mtu} \tag{2.11}$$

$$MCP_{weekend}^{mtu,month} = \frac{1}{count\_of\_non\_weekdays} \sum_{day=1}^{count\_of\_non\_weekdays} MCP_{day}^{mtu} \tag{2.12}$$

A high-level overview of the price signals of the Spot Markets is shown in Figure 2.1, where the average monthly MCPs per market are presented for the first three months of EU Target Model Implementation in the Greek Power Market.

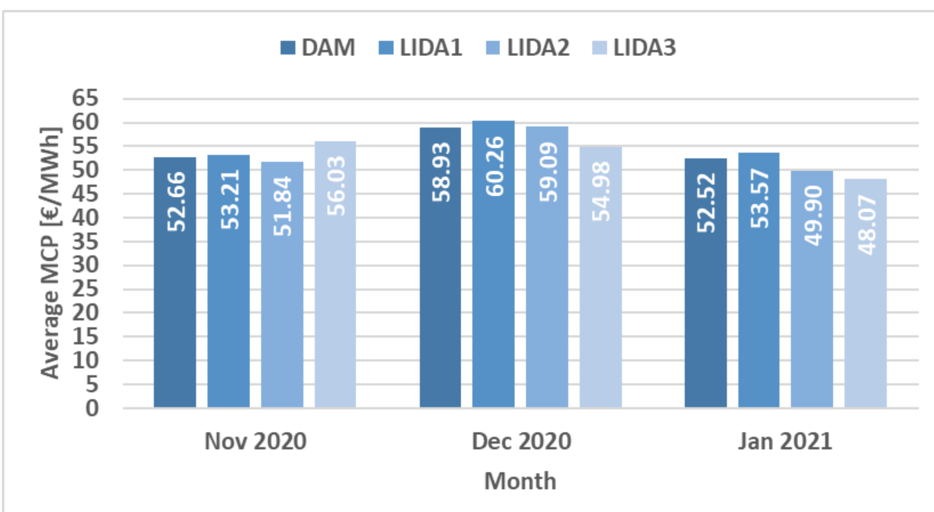


Figure 2.1. Average Monthly Market Clearing Prices per Market and Month

For every following sub-section (DAM, LIDA1, LIDA2, LIDA3) the presentation of the analysis is organized as follows: first the results are presented in a monthly resolution, then the daily statistics are illustrated and analyzed and in the end of each market's analysis sub-section, are presented the Tables with the respective analytical results on a daily resolution.

2.1.1 Day-Ahead Market (DAM)

The Table 2.1 includes the results of the monthly statistics of the DAM MCP, which are also illustrated in Figure 2.2. The highest monthly average MCP resulted in December at 58.93€/MWh and the lowest one, resulted in January at 52.52€/MWh. For November, the minimum and maximum daily MCP were set at 26.29€/MWh and 72.01€/MWh respectively, resulting a spread of 35.72€/MWh. For December, the minimum and maximum MCP were set at 35.75€/MWh and 93.78€/MWh respectively, resulting a spread of 58.03€/MWh. For January, the minimum and maximum MCP were set at 42.28€/MWh and 71.73€/MWh respectively, resulting a spread of 29.46€/MWh.

The column "Spread" shows the volatility of MCP on a monthly basis, where the highest spread was resulted in December at 58.03€/MWh and the lowest spread resulted at 29.46€/MWh in January. Finally, the column "Average Daily Spread" shows the volatility of MPC on a daily basis for the respective month, where the highest spread was resulted in December at 56.99€/MWh and the lowest spread resulted in November at 46.98€/MWh.

Table 2.1. DAM MCP Monthly Statistics

Month	Average [€/MWh]	Min [€/MWh]	Max [€/MWh]	Spread [€/MWh]	Average Daily Spread [€/MWh]
Nov 2020	52.66	36.29	72.01	35.72	46.98
Dec 2020	58.93	35.75	93.78	58.03	56.99
Jan 2021	52.52	42.28	71.73	29.46	49.38

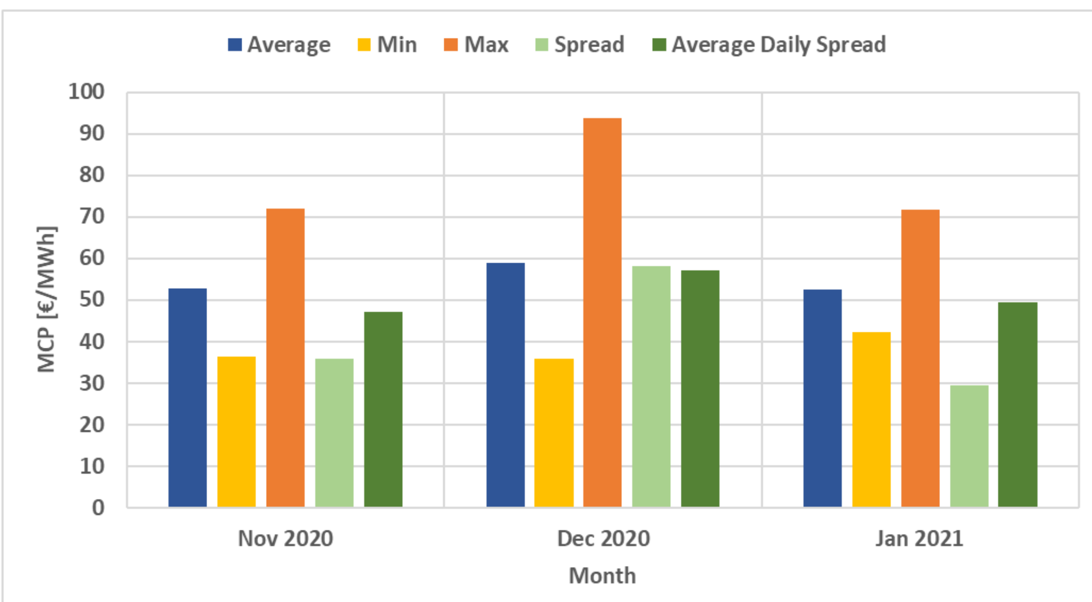


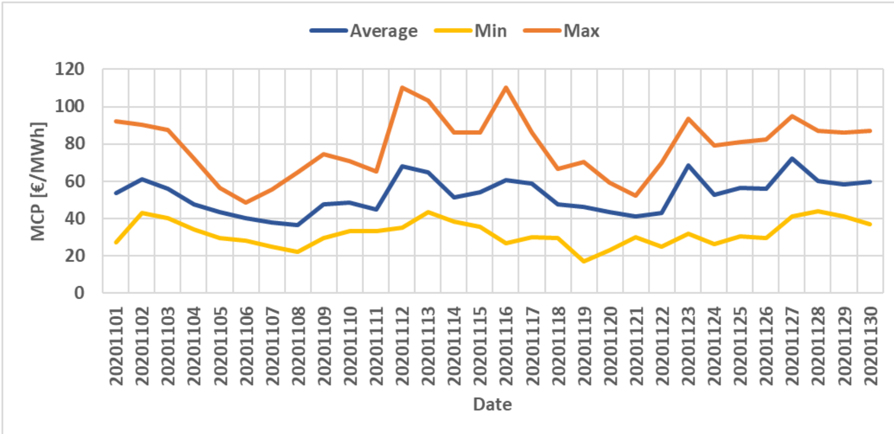
Figure 2.2. DAM MCP Monthly Statistics

In Figures 2.3(a)-(c) the development of the daily average, minimum and maximum DAM MCP are presented for November 2020 to January 2021 respectively. Regarding November, the minimum daily MCP was set 36.29€/MWh on 08.11.2020 and the maximum daily MCP was set at 72.01€/MWh on 27.11.2020. The minimum hourly MCP was set at 17.03€/MWh on 19.11.2020 at MTU 4 and the maximum hourly MCP was set at 110.14€/MWh on 12.11.2020 at MTU 18. Regarding December, the minimum daily MCP was set 35.75€/MWh on 27.12.2020 and the maximum daily MCP was set at 93.78€/MWh on 17.12.2020. The minimum hourly MCP was set at -0.01€/MWh on 01.12.2020 at MTU 3 and the maximum hourly MCP was set at 140.01€/MWh on 17.12.2020 at MTU 19. Regarding January, the minimum daily MCP was set 42.28€/MWh on 31.01.2021 and the maximum daily MCP was set at 71.73€/MWh on 19.01.2021. The minimum hourly MCP was set at 1.5€/MWh on 04.01.2021 at MTU 4 and the maximum hourly MCP was set at 98.02€/MWh on 15.01.2021 at MTU 19.

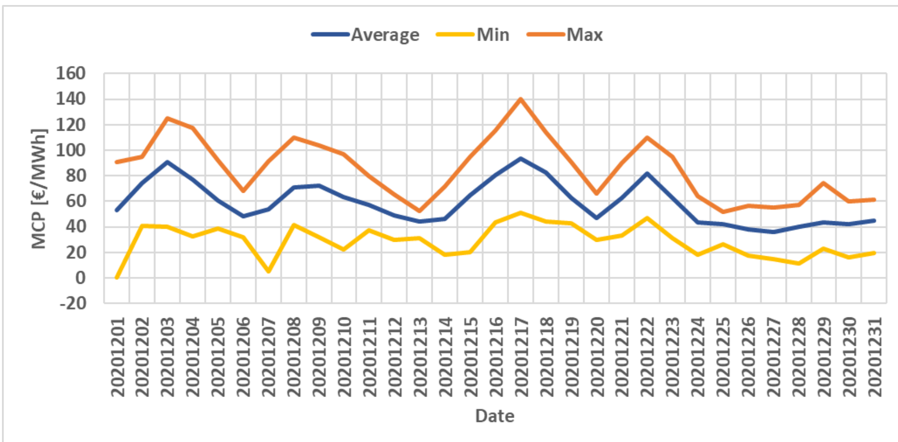
In Figures 2.4(a)-(c) the development of the daily spreads of DAM MCP are presented for November 2020 to January 2021 respectively as well as the trend line of the respective month. Regarding November, the lowest spread was resulted at 20.25€/MWh on 06.11.2020 and the highest one was resulted at 83.48€/MWh on 16.11.2020. Regarding December, the lowest spread was resulted at 20.69€/MWh on 13.12.2020 and the highest one was resulted at 90.72€/MWh on 01.12.2020. Regarding January, the lowest spread was resulted at 8.94€/MWh on 06.01.2021 and the highest one was resulted at 84.00€/MWh on 14.01.2021.

In Figures 2.5(a)-(c) the monthly duration curves of DAM MCP results are presented for November 2020 to January 2021 respectively. The vertical axis corresponds to the MCP price and the horizontal axis corresponds to the percentage of MTUs within a month, for which the resulted MCP was higher compared to the respective price of the vertical axis. Regarding November, the hourly MCP was set above 90€/MWh, 80€/MWh and 60€/MWh at a percentage of 4.86%, 10.00% and 27.08% respectively. Also, the hourly MCP for November was set below 50€/MWh 40€/MWh and 30€/MWh, at a percentage of 52.64%, 21.25% and 5.28% respectively. Regarding December, the hourly MCP was set above 90€/MWh, 80€/MWh and 60€/MWh at a percentage of 15.59%, 23.12% and 37.27% respectively. Also, the hourly MCP for December was set below 50€/MWh 40€/MWh and 30€/MWh, at a percentage of 47.18%, 18.68% and 8.60% respectively. It is worth noting that on 01.12.2020 the MCP was set from 0.00€/MWh to -0.01€/MWh for the during the five MTUs 1-5. Regarding January, the hourly MCP was set above 90€/MWh, 80€/MWh and 60€/MWh at a percentage of 1.34%, 5.11% and 32.53% respectively. Also, the hourly MCP for January was set below 50€/MWh 40€/MWh and 30€/MWh, at a percentage of 45.03%, 16.67% and 10.35% respectively. It is worth noting that the hourly MCP was set below 10€/MWh at a percentage of 1.48%.

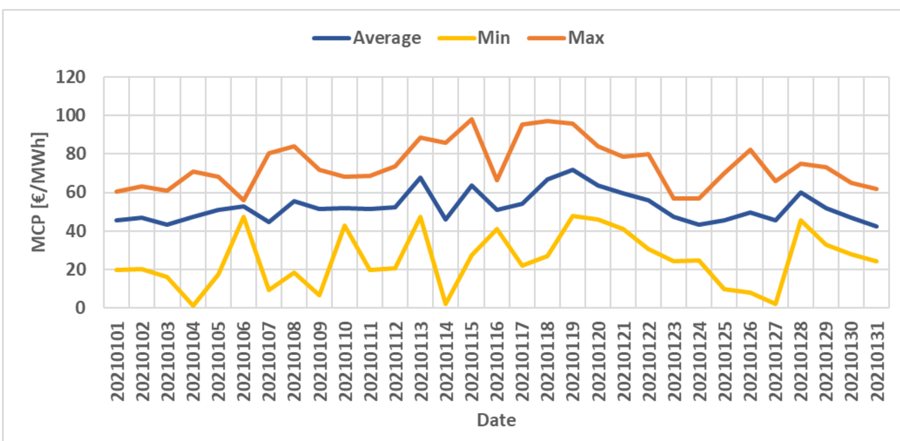
In Figures 2.6(a)-(c) the monthly representative days are presented for November 2020 to January 2021 respectively, and more specifically for each month, three different representative daily curves are formulated for the weekdays (*weekday*), non-weekdays (*weekend*) and for all days (*all-days*). For all three months under study, for the MTUs 6-23, the weekdays curves are higher than the all-days curves and the weekend curves are lower than all-days curves. For the MTUs 1-5 & 24, the deviation between the respective curves is minimal.



(a)

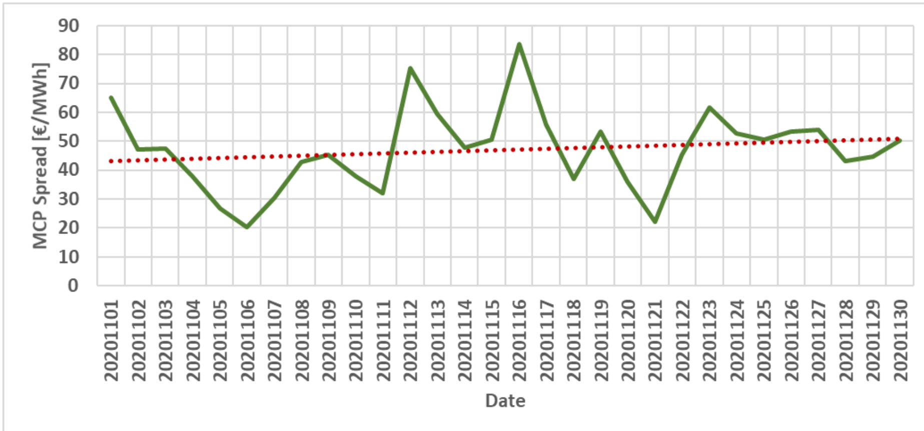


(b)

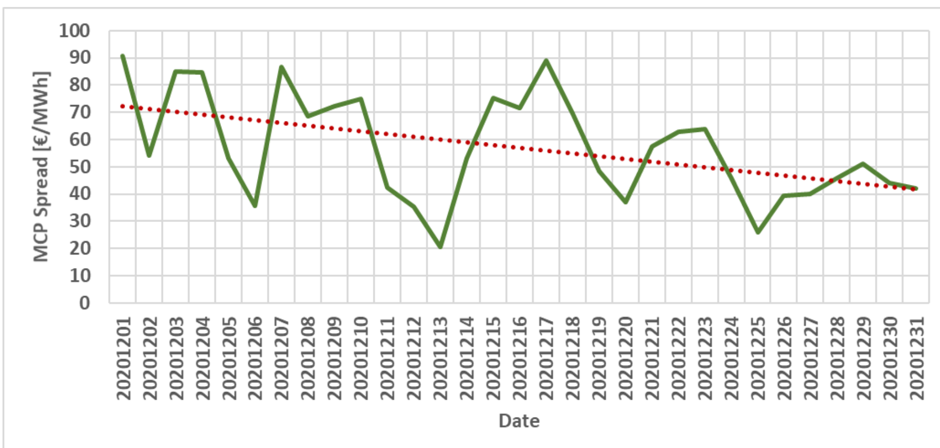


(c)

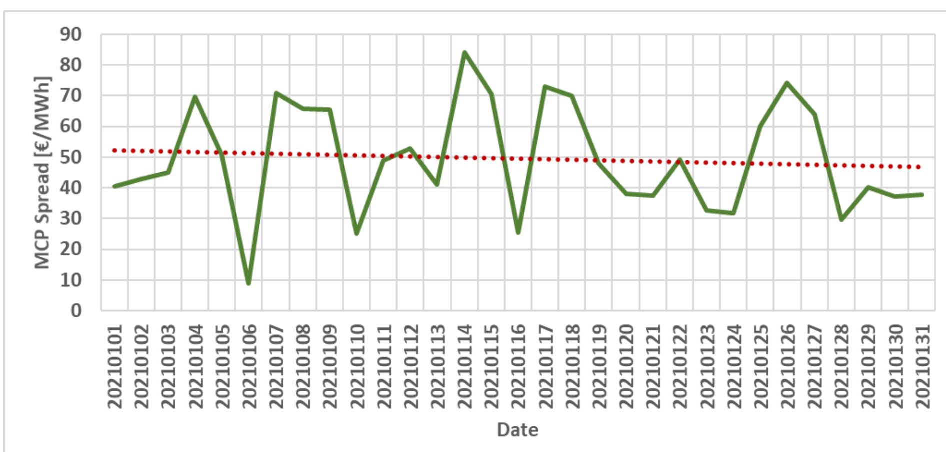
Figure 2.3. DAM MCP Daily Statistics – (a) November 2020; (b) December 2020; (c) January 2021



(a)

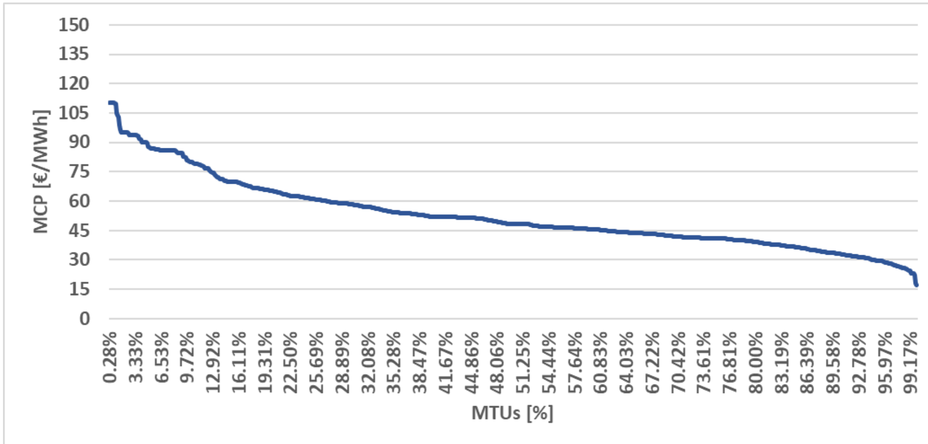


(b)

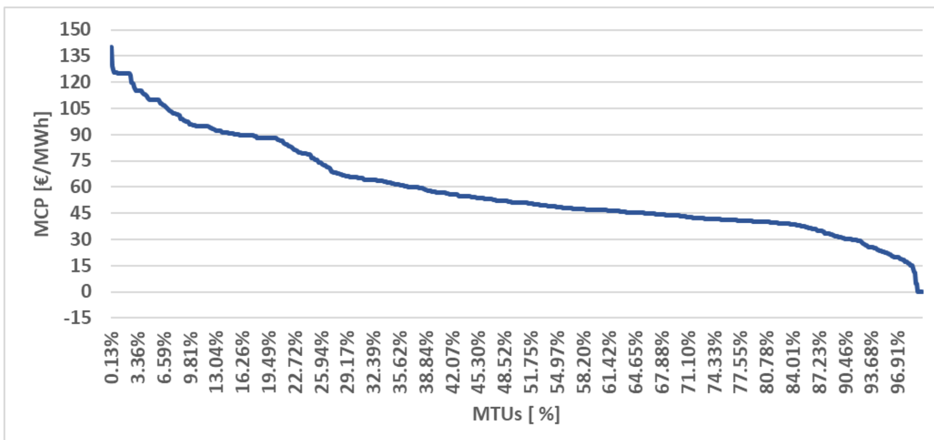


(c)

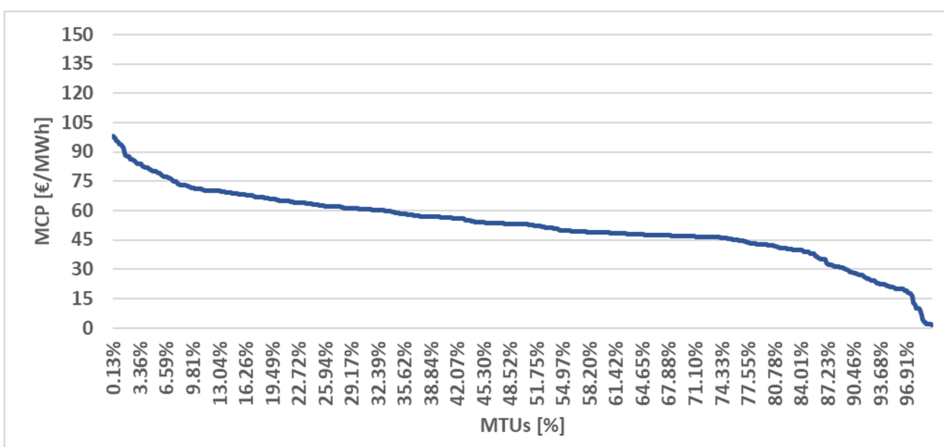
Figure 2.4. DAM MCP Daily Spreads – (a) November 2020; (b) December 2020; (c) January 2021



(a)



(b)



(c)

Figure 2.5. DAM MCP Duration Curves – (a) November 2020; (b) December 2020; (c) January 2021

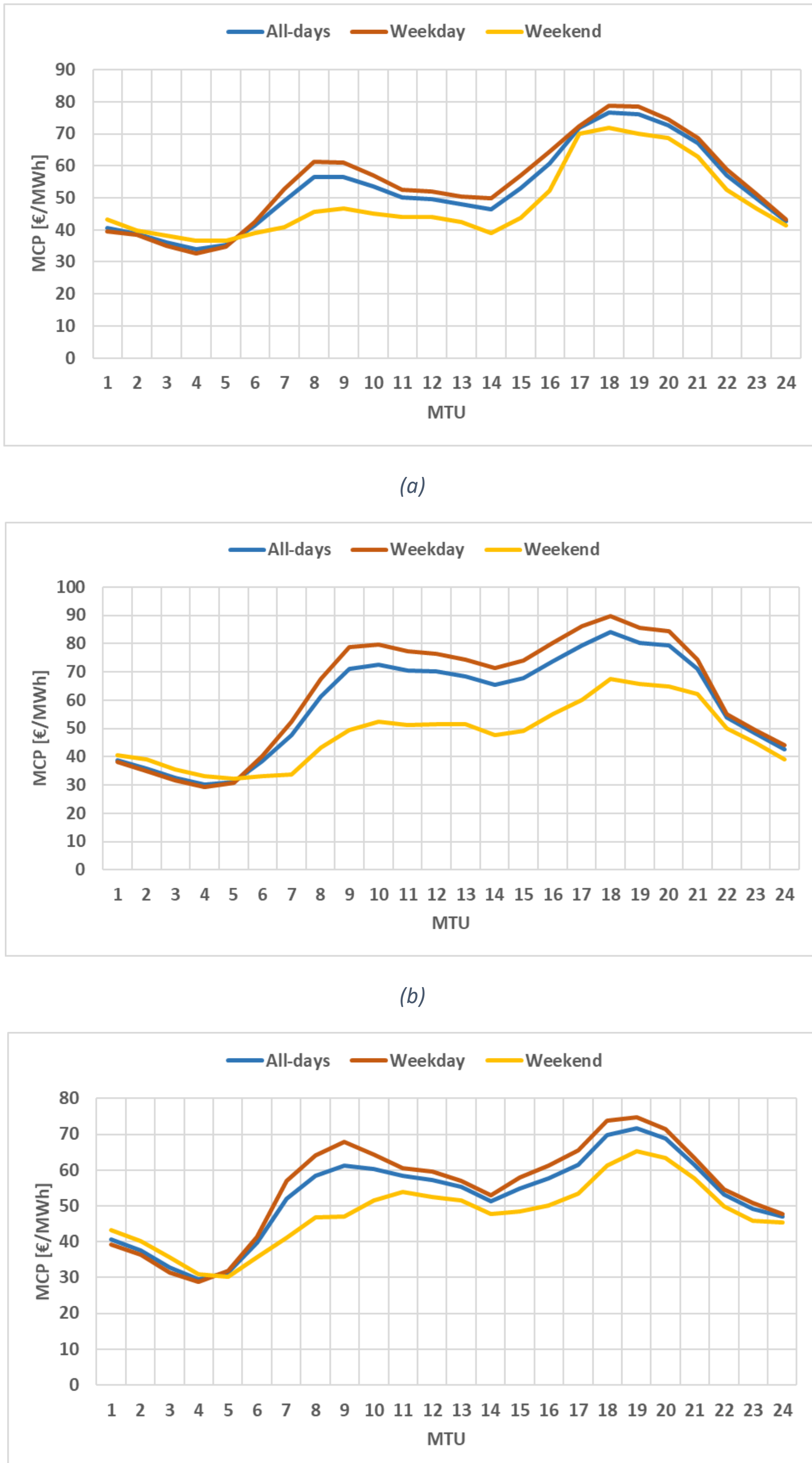


Figure 2.6. DAM Representative Days – (a) November 2020; (b) December 2020; (c) January 2021

In Tables 2.2-2.4 the results of the statistics of the DAM MCP, are presented for November 2020, December 2020 and January 2021 respectively, as calculated based on equations $(2.1) - (2.4)$. More specifically, the results correspond to the average, minimum, maximum and the spread of MCP on a daily resolution analysis and presentation of the results.

Table 2.2. DAM MCP Daily Statistics – November 2020

Date	Average Daily MCP [€/MWh]	Min Daily MCP [€/MWh]	Max Daily MCP [€/MWh]	Daily MCP Spread [€/MWh]
20201101	53.56	27.01	92.02	65.01
20201102	60.99	43.01	90.10	47.09
20201103	56.01	40.25	87.70	47.45
20201104	47.48	34.06	72.00	37.94
20201105	43.25	29.46	56.25	26.79
20201106	40.38	28.05	48.30	20.25
20201107	37.78	24.78	55.36	30.58
20201108	36.29	22.06	65.00	42.94
20201109	47.43	29.43	74.64	45.21
20201110	48.49	33.03	70.98	37.95
20201111	44.80	33.05	65.11	32.06
20201112	68.09	34.86	110.14	75.28
20201113	64.75	43.61	103.09	59.48
20201114	51.20	38.43	86.15	47.72
20201115	54.31	35.56	86.21	50.65
20201116	60.44	26.56	110.04	83.48
20201117	58.87	30.00	85.90	55.90
20201118	47.59	29.62	66.72	37.10
20201119	46.26	17.03	70.37	53.34
20201120	43.64	22.94	59.05	36.11
20201121	41.11	29.98	52.01	22.03
20201122	42.98	24.64	69.88	45.24
20201123	68.36	31.88	93.67	61.79
20201124	52.87	26.38	78.96	52.58
20201125	56.45	30.57	81.02	50.45
20201126	56.12	29.27	82.60	53.33
20201127	72.01	41.32	95.12	53.80
20201128	60.18	43.97	87.04	43.07
20201129	58.14	41.33	85.91	44.58
20201130	59.84	36.76	87.04	50.28

Table 2.3. DAM MCP Daily Statistics – December 2020

Date	Average Daily MCP [€/MWh]	Min Daily MCP [€/MWh]	Max Daily MCP [€/MWh]	Daily MCP Spread [€/MWh]
20201201	52.89	-0.01	90.71	90.72
20201202	74.00	41.05	95.13	54.08
20201203	90.69	40.06	125.12	85.06
20201204	77.27	32.50	117.27	84.77
20201205	60.46	39.00	92.01	53.01
20201206	48.09	32.14	67.96	35.82
20201207	53.69	4.92	91.46	86.54
20201208	71.17	41.38	110.01	68.63
20201209	71.94	32.00	104.10	72.10
20201210	63.09	22.28	97.21	74.93
20201211	56.90	37.00	79.54	42.54
20201212	48.63	29.90	65.23	35.33
20201213	44.01	31.39	52.08	20.69
20201214	46.13	18.14	71.29	53.15
20201215	64.90	19.95	95.17	75.22
20201216	80.36	43.71	115.17	71.46
20201217	93.78	51.02	140.01	88.99
20201218	82.31	44.38	114.10	69.72
20201219	62.33	42.50	91.01	48.51
20201220	47.12	29.47	66.38	36.91
20201221	62.88	32.93	90.29	57.36
20201222	82.02	47.11	110.06	62.95
20201223	62.60	31.13	95.03	63.90
20201224	43.40	18.35	64.20	45.85
20201225	41.83	26.03	51.93	25.90
20201226	37.74	17.22	56.61	39.39
20201227	35.75	15.00	55.00	40.00
20201228	40.38	11.24	56.98	45.74
20201229	43.37	23.00	74.20	51.20
20201230	42.05	16.00	60.08	44.08
20201231	45.19	19.24	61.34	42.10

Table 2.4. DAM MCP Daily Statistics – January 2021

Date	Average Daily MCP [€/MWh]	Min Daily MCP [€/MWh]	Max Daily MCP [€/MWh]	Daily MCP Spread [€/MWh]
20210101	45.58	20.00	60.61	40.61
20210102	47.11	20.08	63.08	43.00
20210103	43.47	16.20	61.09	44.89
20210104	47.46	1.50	71.05	69.55
20210105	50.89	17.57	68.32	50.75
20210106	52.84	47.20	56.14	8.94
20210107	44.64	9.53	80.41	70.88
20210108	55.72	18.25	84.00	65.75
20210109	51.64	6.60	71.99	65.39
20210110	51.96	42.89	68.14	25.25
20210111	51.65	19.95	68.86	48.91
20210112	52.47	20.78	73.64	52.86
20210113	67.76	47.27	88.33	41.06
20210114	46.16	2.00	86.00	84.00
20210115	63.69	27.60	98.02	70.42
20210116	50.96	41.00	66.40	25.40
20210117	53.98	22.22	95.27	73.05
20210118	66.95	27.21	97.16	69.95
20210119	71.73	47.90	95.90	48.00
20210120	63.45	46.00	84.05	38.05
20210121	59.68	41.02	78.62	37.60
20210122	56.05	30.89	80.00	49.11
20210123	47.24	24.24	57.00	32.76
20210124	43.28	25.00	56.67	31.67
20210125	45.70	10.00	69.97	59.97
20210126	49.53	8.00	82.04	74.04
20210127	45.39	1.98	66.06	64.08
20210128	59.98	45.51	75.01	29.50
20210129	52.13	32.84	73.00	40.16
20210130	46.75	27.80	65.00	37.20
20210131	42.28	24.15	62.04	37.89

2.1.2 Local Intra-Day Auction 1 (LIDA1)

The Table 2.5 includes the results of the monthly statistics of the LIDA1 MCP, which are also illustrated in Figure 2.7. The highest monthly average MCP resulted in December at 60.26€/MWh and the lowest one, resulted in November at 53.21€/MWh. For November, the minimum and maximum daily MCP were set at 27.49€/MWh and 83.85€/MWh respectively, resulting a spread of 56.36€/MWh. For December, the minimum and maximum MCP were set at 16.27€/MWh and 115.48€/MWh respectively, resulting a spread of 99.21€/MWh. For January, the minimum and maximum MCP were set at 30.40€/MWh and 95.85€/MWh respectively, resulting a spread of 65.46€/MWh.

The column "Spread" shows the volatility of MCP on a monthly basis, where the highest spread was resulted in December at 99.21€/MWh and the lowest spread resulted at 56.36€/MWh in November. Finally, the column "Average Daily Spread" shows the volatility of MPC on a daily basis for the respective month, where the highest spread was resulted in December at 64.68€/MWh and the lowest spread resulted in November at 56.00€/MWh.

Table 2.5. LIDA1 MCP Monthly Statistics

Month	Average [€/MWh]	Min [€/MWh]	Max [€/MWh]	Spread [€/MWh]	Average Daily Spread [€/MWh]
Nov 2020	53.21	27.49	83.85	56.36	56.00
Dec 2020	60.26	16.27	115.48	99.21	64.68
Jan 2021	53.57	30.40	95.85	65.46	59.68

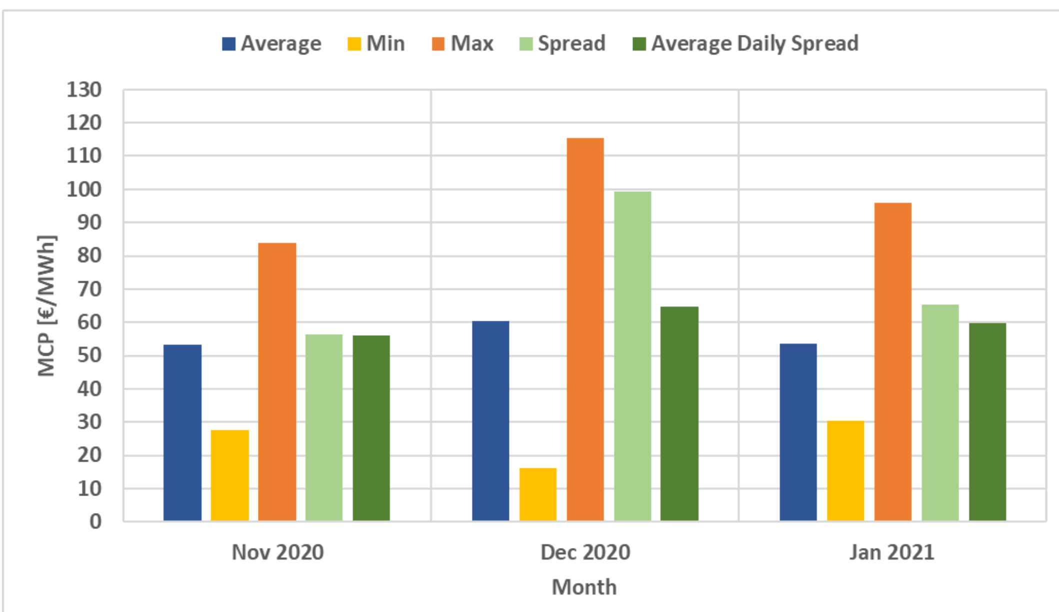


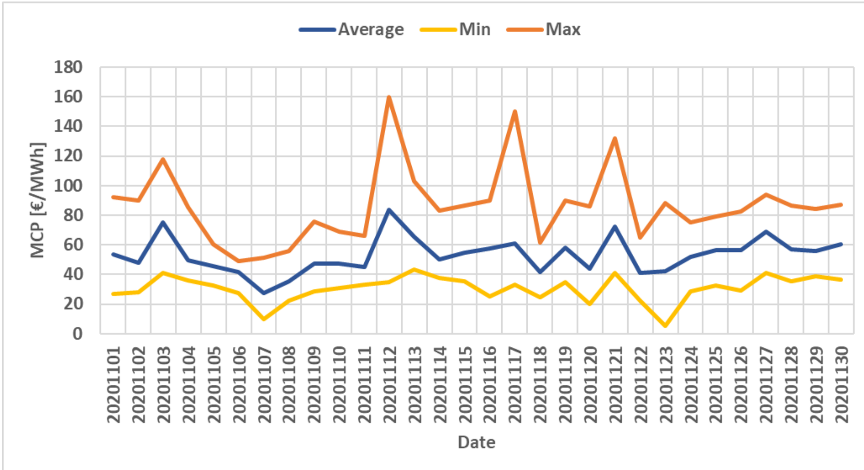
Figure 2.7. LIDA1 MCP Monthly Statistics

In Figures 2.8(a)-(c) the development of the daily average, minimum and maximum LIDA1 MCP are presented for November 2020 to January 2021 respectively. Regarding November, the minimum daily MCP was set 27.49€/MWh on 07.11.2020 and the maximum daily MCP was set at 83.85€/MWh on 12.11.2020. The minimum hourly MCP was set at 5.10€/MWh on 23.11.2020 at MTU 24 and the maximum hourly MCP was set at 160.00€/MWh on 12.11.2020 at MTU 15. Regarding December, the minimum daily MCP was set 16.27€/MWh on 26.12.2020 and the maximum daily MCP was set at 115.48€/MWh on 17.12.2020. The minimum hourly MCP was set at -1.20€/MWh on 28.12.2020 at MTU 5 and the maximum hourly MCP was set at 180.00€/MWh on 17.12.2020 at MTU 19. Regarding January, the minimum daily MCP was set 30.40€/MWh on 06.01.2021 and the maximum daily MCP was set at 95.85€/MWh on 18.01.2021. The minimum hourly MCP was set at 0.00€/MWh on 02.01.2021 at MTUs 4 & 5 and the maximum hourly MCP was set at 150.00€/MWh on 04.01.2021 at MTUs 7 & 24 and on 18.01.2021 at MTU 10.

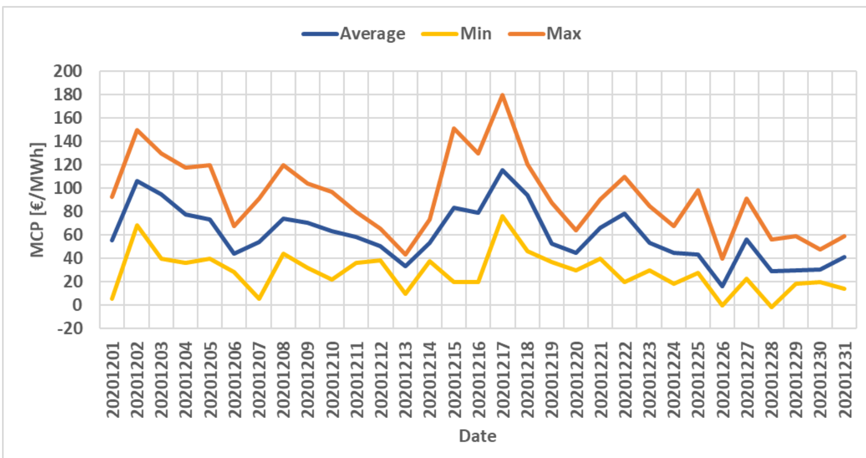
In Figures 2.9(a)-(c) the development of the daily spreads of LIDA1 MCP are presented for November 2020 to January 2021 respectively as well as the trend line of the respective month. Regarding November, the lowest spread was resulted at 21.37€/MWh on 06.11.2020 and the highest one was resulted at 125.14€/MWh on 12.11.2020. Regarding December, the lowest spread was resulted at 26.91€/MWh on 12.12.2020 and the highest one was resulted at 131.72€/MWh on 15.12.2020. Regarding January, the lowest spread was resulted at 23.57€/MWh on 24.01.2021 and the highest one was resulted at 130.00€/MWh on 04.01.2021.

In Figures 2.10(a)-(c) the monthly duration curves of LIDA1 MCP results are presented for November 2020 to January 2021 respectively. The vertical axis corresponds to the MCP price and the horizontal axis corresponds to the percentage of MTUs within a month, for which the resulted MCP was higher compared to the respective price of the vertical axis. Regarding November, the hourly MCP was set above 90€/MWh, 80€/MWh and 60€/MWh at a percentage of 5.69%, 13.06% and 29.44% respectively. Also, the hourly MCP for November was set below 50€/MWh 40€/MWh and 30€/MWh, at a percentage of 56.53%, 23.89% and 8.19% respectively. Regarding December, the hourly MCP was set above 90€/MWh, 80€/MWh and 60€/MWh at a percentage of 20.43%, 26.48% and 39.25% respectively. Also, the hourly MCP for December was set below 50€/MWh 40€/MWh and 30€/MWh, at a percentage of 49.87%, 26.34% and 13.31% respectively. It is worth noting that on 28.12.2020 the MCP was set from 0.10€/MWh to -1.20€/MWh for five MTUs and on 26.12.2020 the MCP was set at 0.10€/MWh for five MTUs. Regarding January, the hourly MCP was set above 90€/MWh, 80€/MWh and 60€/MWh at a percentage of 9.54%, 12.50% and 32.66% respectively. Also, the hourly MCP for January was set below 50€/MWh 40€/MWh and 30€/MWh, at a percentage of 51.34%, 24.60% and 15.59% respectively. It is worth noting that the hourly MCP was set below at 0.00€/MWh for the MTUs 4 & 5 on 02.01.2021.

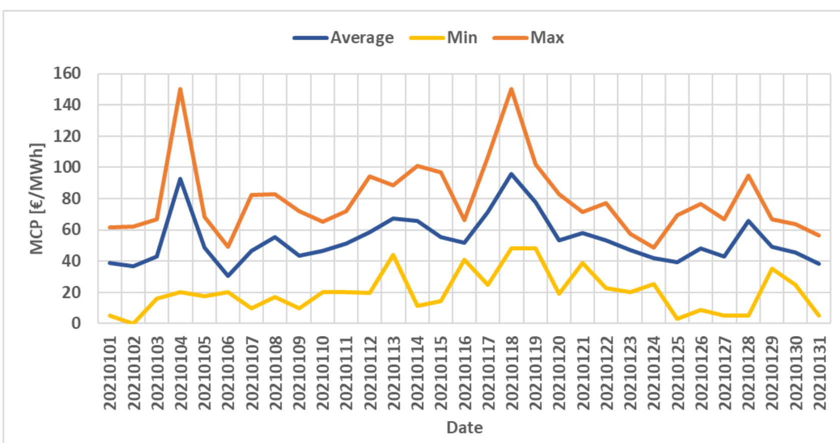
In Figures 2.11(a)-(c) the monthly representative days are presented for November 2020 to January 2021 respectively, and more specifically for each month, three different representative daily curves are formulated for the weekdays (*weekday*), non-weekdays (*weekend*) and for all days (*all-days*). Regarding November, for the MTUs 7-23, the weekday curve is higher than the all-days curve and the weekend curve is lower than the all-days curve. For MTUs 1-6 & 24, the weekend curve is higher than the other two and the weekday curve is lower than the all-days curve. Regarding December and January, the for the MTUs 1-4 the curves have minimal deviation from one another. For the MTUs 5-24 the weekend curve is lower than all-days curve and the weekday curve is higher than the all-days curve.



(a)

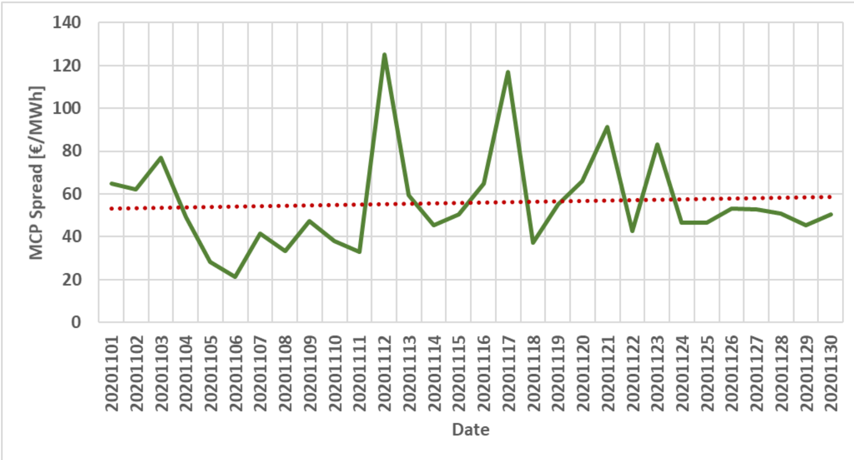


(b)

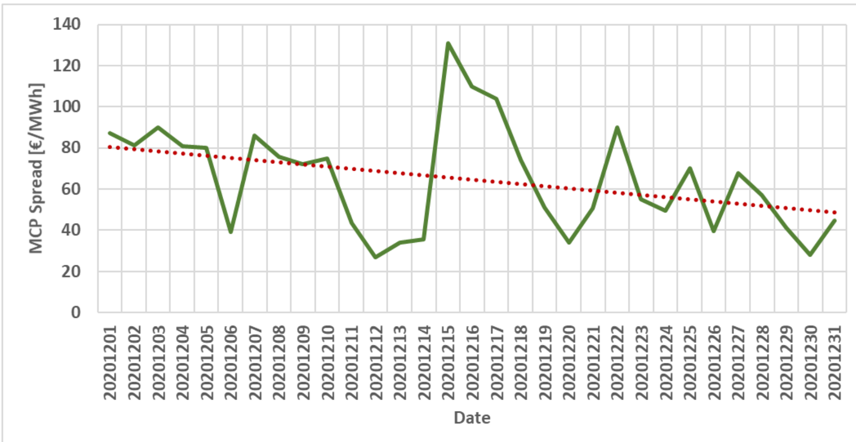


(c)

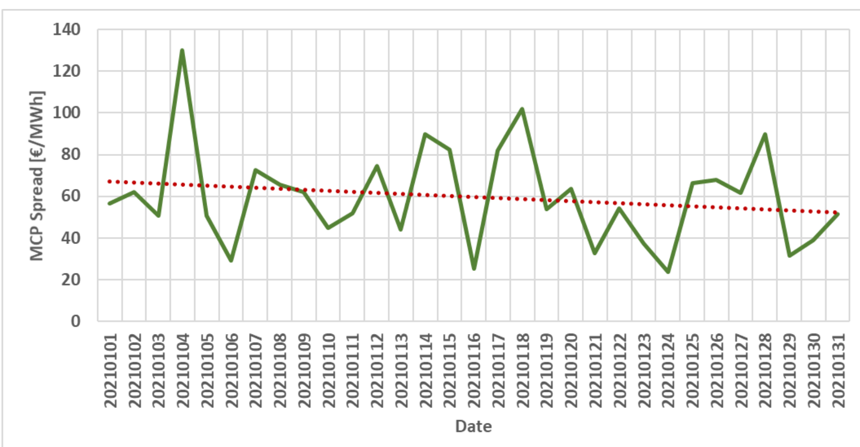
Figure 2.8. LIDA1 MCP Daily Statistics – (a) November 2020; (b) December 2020; (c) January 2021



(a)

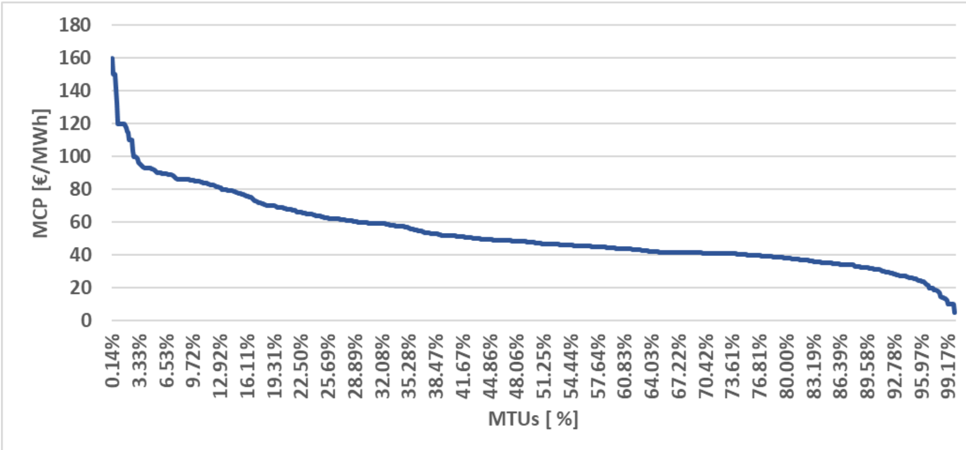


(b)

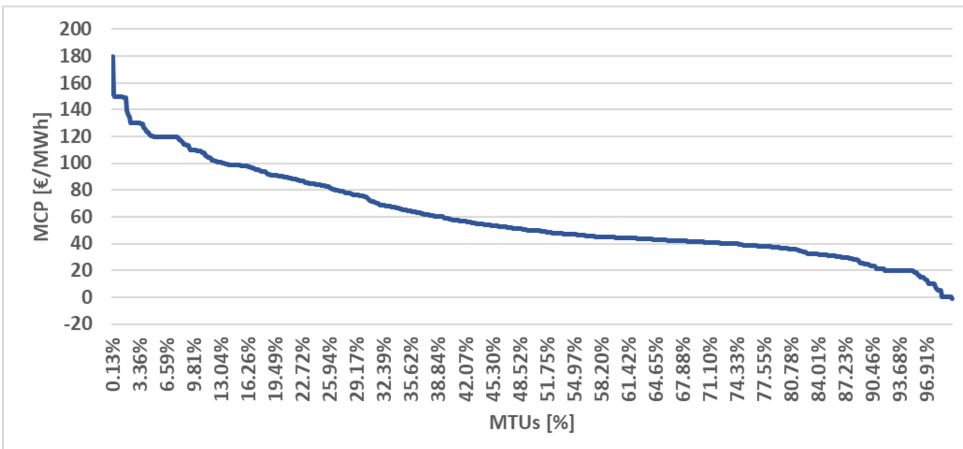


(c)

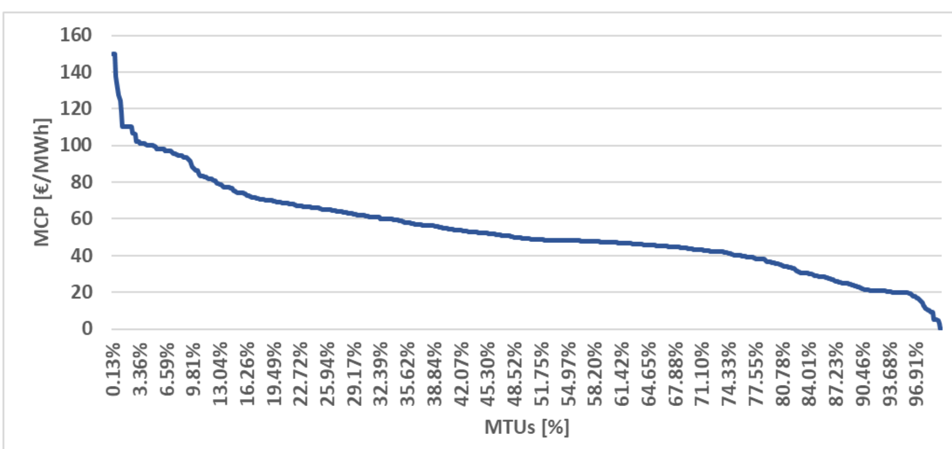
Figure 2.9. LIDA1 MCP Daily Spreads – (a) November 2020; (b) December 2020; (c) January 2021



(a)

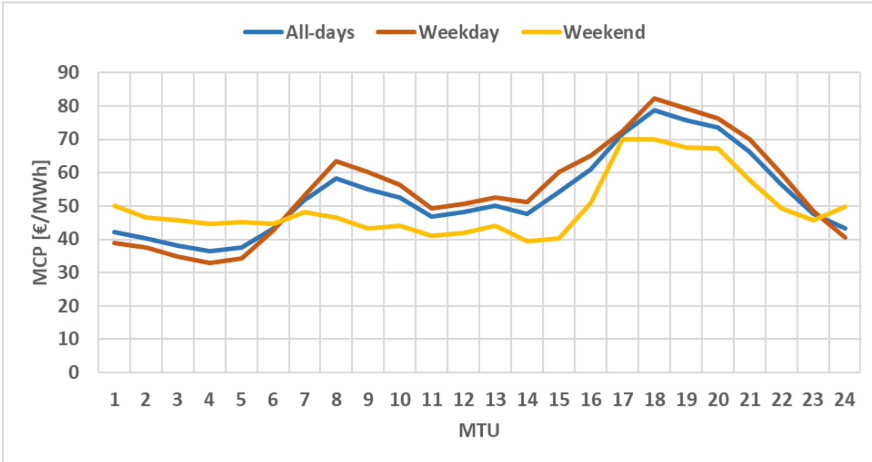


(b)

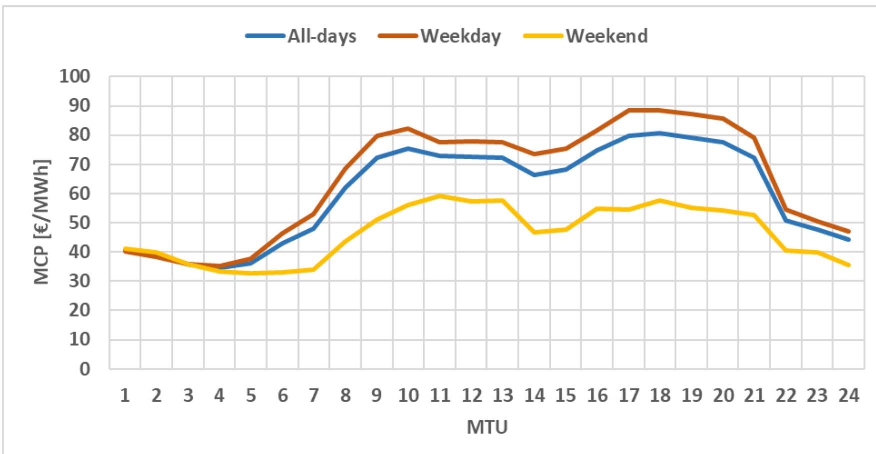


(c)

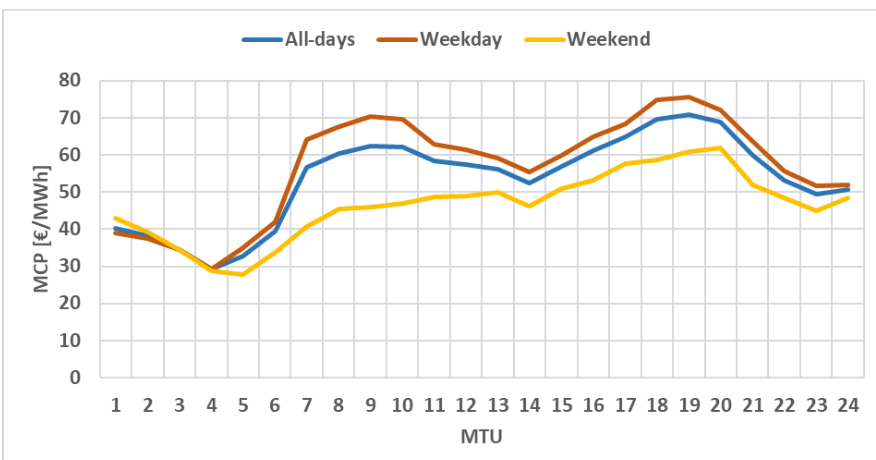
Figure 2.10. LIDA1 MCP Duration Curves – (a) November 2020; (b) December 2020; (c) January 2021



(a)



(b)



(c)

Figure 2.11. LIDA1 Representative Days – (a) November 2020; (b) December 2020; (c) January 2021

In Tables 2.6-2.8 the results of the statistics of the LIDA1 MCP, are presented for November 2020, December 2020 and January 2021 respectively, as calculated based on equations $(2.1) - (2.4)$. More specifically, the results correspond to the average, minimum, maximum and the spread of MCP on a daily resolution analysis and presentation of the results.

Table 2.6. LIDA1 MCP Daily Statistics – November 2020

Date	Average Daily MCP [€/MWh]	Min Daily MCP [€/MWh]	Max Daily MCP [€/MWh]	Daily MCP Spread [€/MWh]
20201101	53.70	27.11	92.12	65.01
20201102	47.74	28.00	89.98	61.98
20201103	75.39	40.89	117.70	76.81
20201104	49.55	36.25	85.70	49.45
20201105	45.40	32.48	60.67	28.19
20201106	41.71	27.63	49.00	21.37
20201107	27.49	10.10	51.45	41.35
20201108	35.39	22.56	56.00	33.44
20201109	47.39	28.49	76.00	47.51
20201110	47.63	30.88	68.90	38.02
20201111	45.30	33.05	66.00	32.95
20201112	83.85	34.86	160.00	125.14
20201113	65.53	43.61	103.09	59.48
20201114	50.12	37.71	83.25	45.54
20201115	54.67	35.67	86.32	50.65
20201116	57.33	25.17	90.04	64.87
20201117	61.02	33.00	150.00	117.00
20201118	41.74	24.62	61.72	37.10
20201119	58.06	35.00	89.98	54.98
20201120	44.03	20.00	86.01	66.01
20201121	72.19	40.86	132.24	91.38
20201122	41.04	22.25	64.86	42.61
20201123	41.98	5.10	88.23	83.13
20201124	51.87	28.58	75.16	46.58
20201125	56.65	32.57	79.16	46.59
20201126	56.66	29.27	82.60	53.33
20201127	69.23	41.19	93.93	52.74
20201128	57.10	35.55	86.54	50.99
20201129	56.05	39.05	84.51	45.46
20201130	60.58	36.76	87.04	50.28

Table 2.7. LIDA1 MCP Daily Statistics – December 2020

Date	Average Daily MCP [€/MWh]	Min Daily MCP [€/MWh]	Max Daily MCP [€/MWh]	Daily MCP Spread [€/MWh]
20201201	55.82	5.32	92.35	87.03
20201202	105.95	68.63	150.00	81.37
20201203	94.73	40.06	130.00	89.94
20201204	77.92	36.58	117.27	80.69
20201205	73.68	40.04	120.00	79.96
20201206	44.31	28.76	67.96	39.20
20201207	54.09	5.38	91.46	86.08
20201208	74.19	44.38	120.00	75.62
20201209	70.76	32.00	104.10	72.10
20201210	63.13	22.28	97.21	74.93
20201211	58.32	36.00	79.54	43.54
20201212	50.32	38.32	65.23	26.91
20201213	33.57	9.80	43.67	33.87
20201214	53.07	37.87	73.65	35.78
20201215	83.66	20.00	151.00	131.00
20201216	79.32	20.00	129.67	109.67
20201217	115.48	76.02	180.00	103.98
20201218	93.73	46.58	120.53	73.95
20201219	52.44	36.83	87.74	50.91
20201220	45.04	29.82	64.00	34.18
20201221	66.53	39.93	90.69	50.76
20201222	78.48	20.00	110.06	90.06
20201223	53.38	30.10	85.15	55.05
20201224	44.58	18.35	68.02	49.67
20201225	43.08	27.84	98.00	70.16
20201226	16.27	0.10	39.79	39.69
20201227	55.94	22.97	90.91	67.94
20201228	29.25	-1.20	55.96	57.16
20201229	29.59	18.11	59.20	41.09
20201230	30.48	20.00	48.00	28.00
20201231	41.10	14.18	58.94	44.76

Table 2.8. LIDA1 MCP Daily Statistics – January 2021

Date	Average Daily MCP [€/MWh]	Min Daily MCP [€/MWh]	Max Daily MCP [€/MWh]	Daily MCP Spread [€/MWh]
20210101	38.94	4.89	61.61	56.72
20210102	36.54	0.00	61.99	61.99
20210103	43.07	16.20	66.73	50.53
20210104	92.79	20.00	150.00	130.00
20210105	48.54	17.58	68.32	50.74
20210106	30.40	20.00	49.29	29.29
20210107	46.59	9.68	82.41	72.73
20210108	55.28	17.25	82.74	65.49
20210109	43.50	10.00	71.99	61.99
20210110	46.33	20.00	64.99	44.99
20210111	51.35	19.95	71.76	51.81
20210112	58.47	19.78	94.34	74.56
20210113	67.44	44.23	88.33	44.10
20210114	65.50	11.11	101.09	89.98
20210115	55.39	14.40	96.93	82.53
20210116	51.62	41.00	66.40	25.40
20210117	71.59	25.01	106.84	81.83
20210118	95.85	48.18	150.00	101.82
20210119	77.79	48.19	101.90	53.71
20210120	53.37	18.99	82.76	63.77
20210121	58.17	39.00	71.69	32.69
20210122	53.56	22.94	77.11	54.17
20210123	47.13	20.00	57.45	37.45
20210124	41.84	25.11	48.68	23.57
20210125	39.23	3.03	69.51	66.48
20210126	48.38	9.00	76.83	67.83
20210127	43.05	5.00	66.81	61.81
20210128	65.72	5.00	94.87	89.87
20210129	49.37	35.31	67.00	31.69
20210130	45.72	24.80	63.76	38.96
20210131	38.15	5.00	56.47	51.47

2.1.3 Local Intra-Day Auction 2 (LIDA2)

The Table 2.9 includes the results of the monthly statistics of the LIDA2 MCP, which are also illustrated in Figure 2.12. The highest monthly average MCP resulted in December at 59.09€/MWh and the lowest one, resulted in January at 49.90€/MWh. For November, the minimum and maximum daily MCP were set at 35.37€/MWh and 75.65€/MWh respectively, resulting a spread of 40.28€/MWh. For December, the minimum and maximum MCP were set at 12.55€/MWh and 132.28€/MWh respectively, resulting a spread of 119.72€/MWh. For January, the minimum and maximum MCP were set at 18.75€/MWh and 88.63€/MWh respectively, resulting a spread of 69.89€/MWh.

The column "Spread" shows the volatility of MCP on a monthly basis, where the highest spread was resulted in December at 119.72€/MWh and the lowest spread resulted at 40.28€/MWh in November. Finally, the column "Average Daily Spread" shows the volatility of MPC on a daily basis for the respective month, where the highest spread was resulted in December at 73.08€/MWh and the lowest spread resulted in November at 50.50€/MWh.

Table 2.9. LIDA2 MCP Monthly Statistics

Month	Average [€/MWh]	Min [€/MWh]	Max [€/MWh]	Spread [€/MWh]	Average Daily Spread [€/MWh]
Nov 2020	51.84	35.37	75.65	40.28	50.50
Dec 2020	59.09	12.55	132.28	119.72	73.08
Jan 2021	49.90	18.75	88.63	69.89	61.92

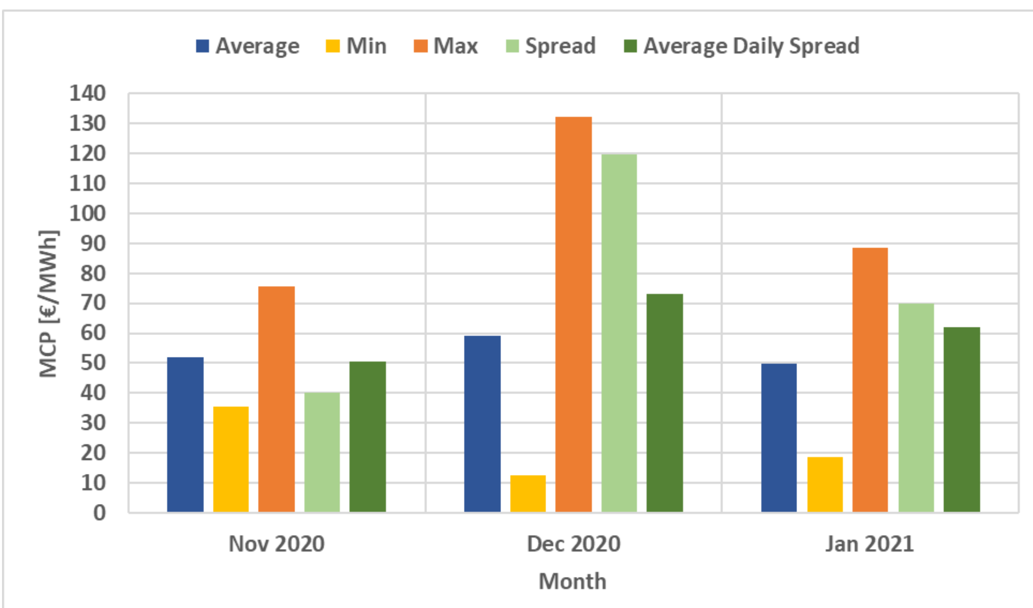


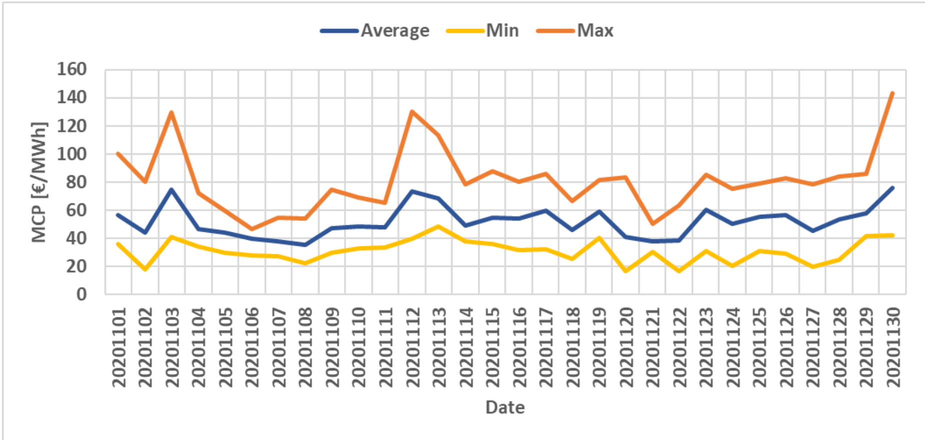
Figure 2.12. LIDA2 MCP Monthly Statistics

In Figures 2.13(a)-(c) the development of the daily average, minimum and maximum LIDA2 MCP are presented for November 2020 to January 2021 respectively. Regarding November, the minimum daily MCP was set 35.37€/MWh on 08.11.2020 and the maximum daily MCP was set at 75.65€/MWh on 30.11.2020. The minimum hourly MCP was set at 16.34€/MWh on 22.11.2020 at MTU 12 and the maximum hourly MCP was set at 143.45€/MWh on 30.11.2020 at MTU 6. Regarding December, the minimum daily MCP was set 12.55€/MWh on 26.12.2020 and the maximum daily MCP was set at 132.28€/MWh on 17.12.2020. The minimum hourly MCP was set at -10.00€/MWh on 23.12.2020 at MTU 3 and the maximum hourly MCP was set at 238.33€/MWh on 02.12.2020 at MTU 13. Regarding January, the minimum daily MCP was set 18.75€/MWh on 06.01.2021 and the maximum daily MCP was set at 88.63€/MWh on 18.01.2021. The minimum hourly MCP was set at -19.92€/MWh on 02.01.2021 at MTU 5 and the maximum hourly MCP was set at 137.16€/MWh on 18.01.2021 at MTU 18.

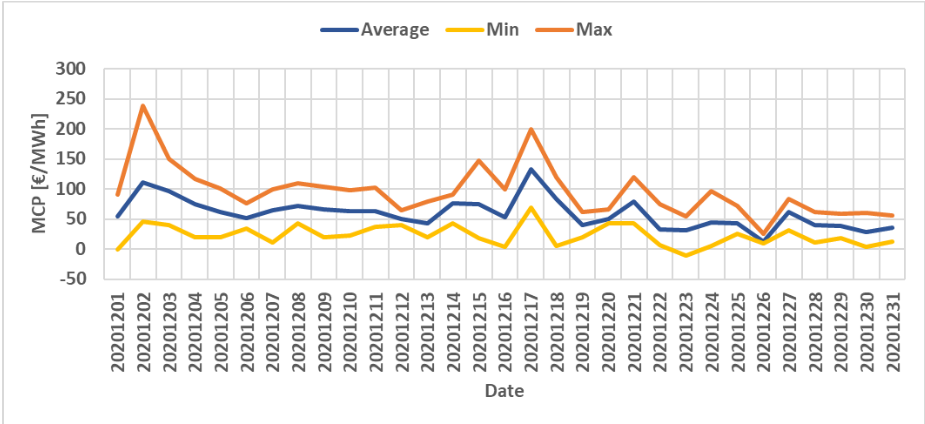
In Figures 2.14(a)-(c) the development of the daily spreads of LIDA2 MCP are presented for November 2020 to January 2021 respectively as well as the trend line of the respective month. Regarding November, the lowest spread was resulted at 18.97€/MWh on 06.11.2020 and the highest one was resulted at 101.19€/MWh on 30.11.2020. Regarding December, the lowest spread was resulted at 14.99€/MWh on 26.12.2020 and the highest one was resulted at 192.42€/MWh on 02.12.2020. Regarding January, the lowest spread was resulted at 24.97€/MWh on 24.01.2021 and the highest one was resulted at 109.95€/MWh on 18.01.2021.

In Figures 2.15(a)-(c) the monthly duration curves of LIDA2 MCP results are presented for November 2020 to January 2021 respectively. The vertical axis corresponds to the MCP price and the horizontal axis corresponds to the percentage of MTUs within a month, for which the resulted MCP was higher compared to the respective price of the vertical axis. Regarding November, the hourly MCP was set above 90€/MWh, 80€/MWh and 60€/MWh at a percentage of 2.64%, 8.07% and 25.59% respectively. Also, the hourly MCP for November was set below 50€/MWh 40€/MWh and 30€/MWh, at a percentage of 56.75%, 24.48% and 6.82% respectively. Regarding December, the hourly MCP was set above 90€/MWh, 80€/MWh and 60€/MWh at a percentage of 17.90%, 25.17% and 38.76% respectively. Also, the hourly MCP for December was set below 50€/MWh 40€/MWh and 30€/MWh, at a percentage of 50.74%, 28.67% and 16.69% respectively. It is worth noting that on 23.12.2020 the MCP was set from -5.01€/MWh to -10.00€/MWh during the 3 consecutive MTUs 3-5. Regarding January, the hourly MCP was set above 90€/MWh, 80€/MWh and 60€/MWh at a percentage of 4.30%, 8.06% and 28.76% respectively. Also, the hourly MCP for January was set below 50€/MWh 40€/MWh and 30€/MWh, at a percentage of 52.96%, 26.88% and 18.55% respectively. It is worth noting that on 02.01.2020 the MCP was set at -12.74€/MWh and -19.92€/MWh for the MTUs 4 and 5 respectively.

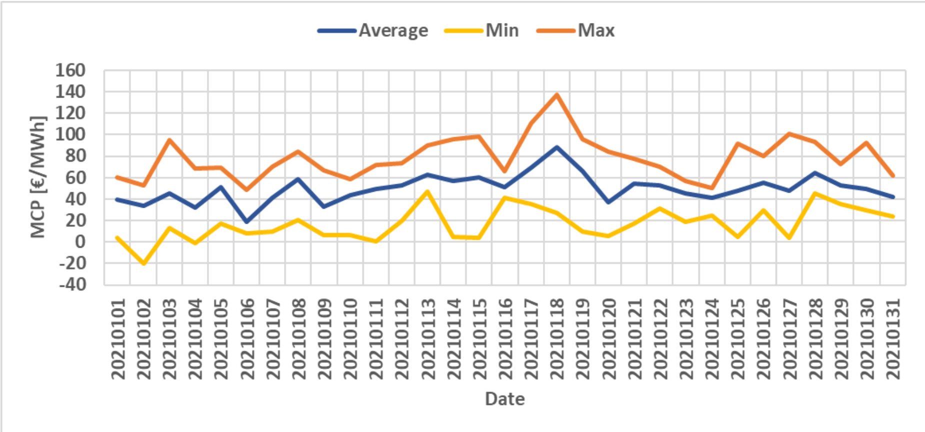
In Figures 2.16(a)-(c) the monthly representative days are presented for November 2020 to January 2021 respectively, and more specifically for each month, three different representative daily curves are formulated for the weekdays (*weekday*), non-weekdays (*weekend*) and for all days (*all-days*). Regarding November, for the MTUs 6-23, the weekend curve is lower than the all-days curve and the weekday curve is higher than the all-days curve. For MTUs 1-5 & 24, the deviation between one another is minimal. Regarding December and January, the for the MTUs 1-4 the weekend curves are higher than the other two and the weekday curves are lower than the all-days curves. For the rest of MTUs (5-24) the weekday curves are higher than the all-days curves and the weekend curves are lower than the all-days curves.



(a)

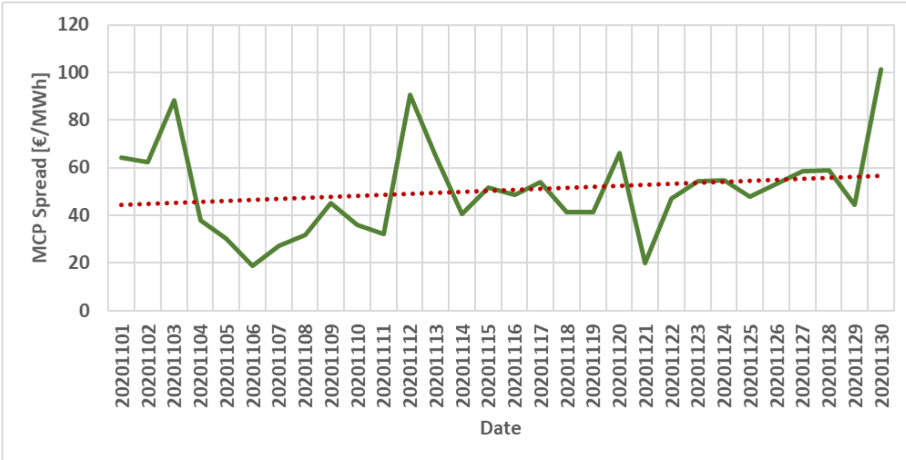


(b)

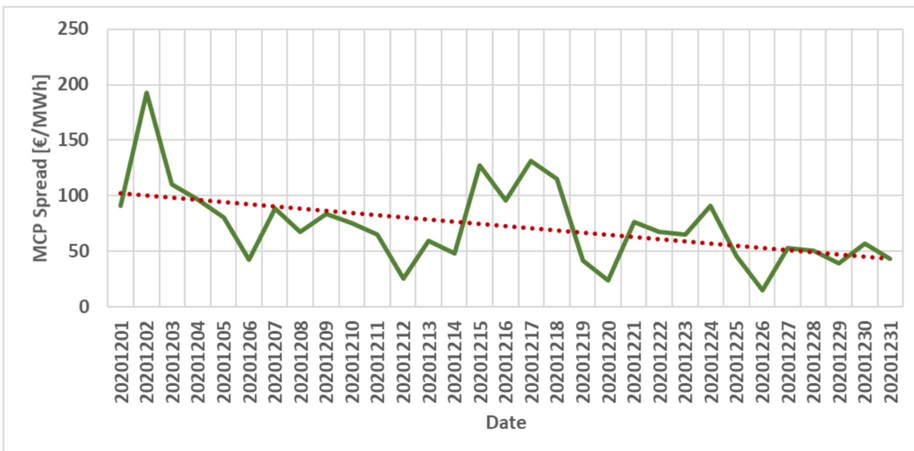


(c)

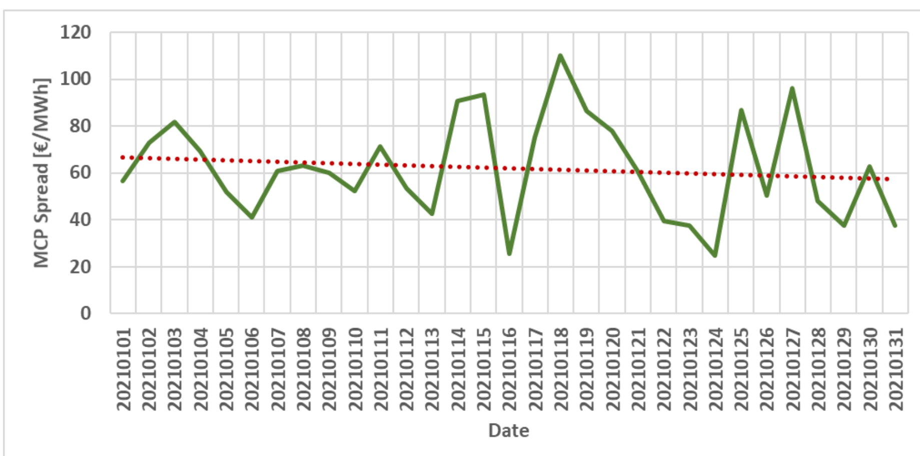
Figure 2.13. LIDA2 MCP Daily Statistics – (a) November 2020; (b) December 2020; (c) January 2021



(a)

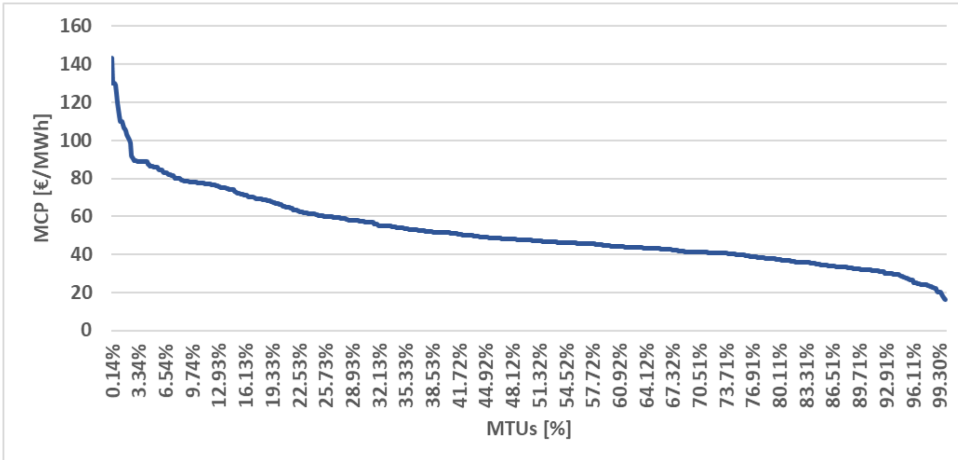


(b)

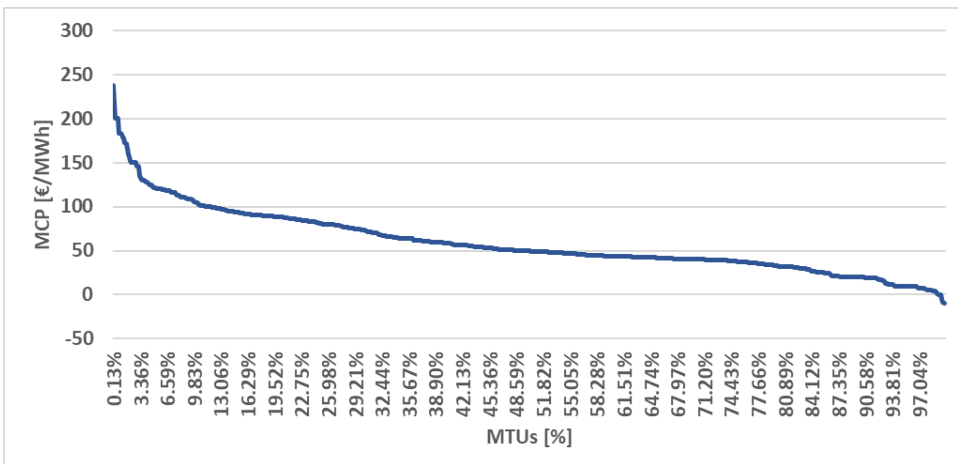


(c)

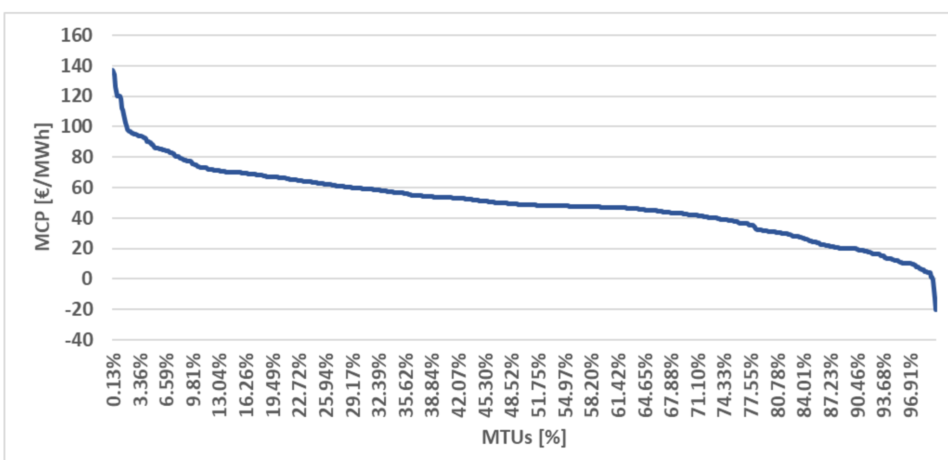
Figure 2.14. LIDA2 MCP Daily Spreads – (a) November 2020; (b) December 2020; (c) January 2021



(a)

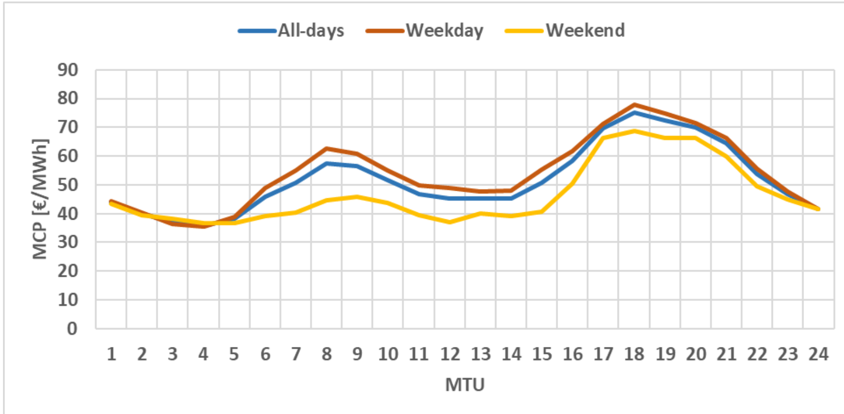


(b)

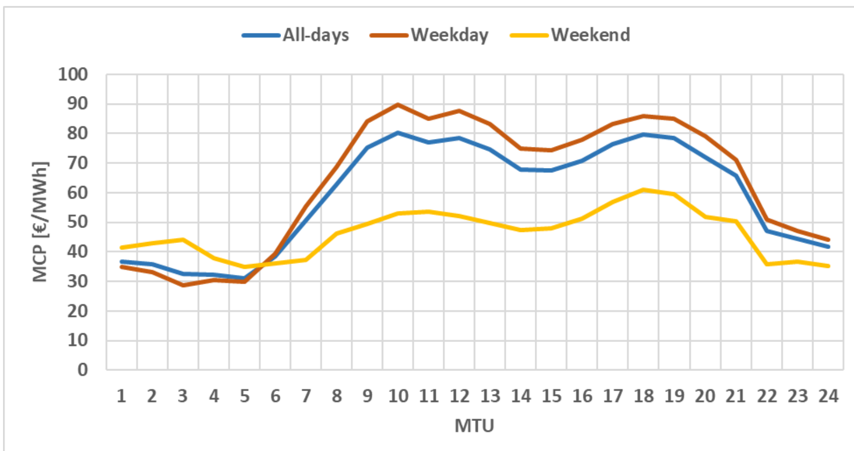


(c)

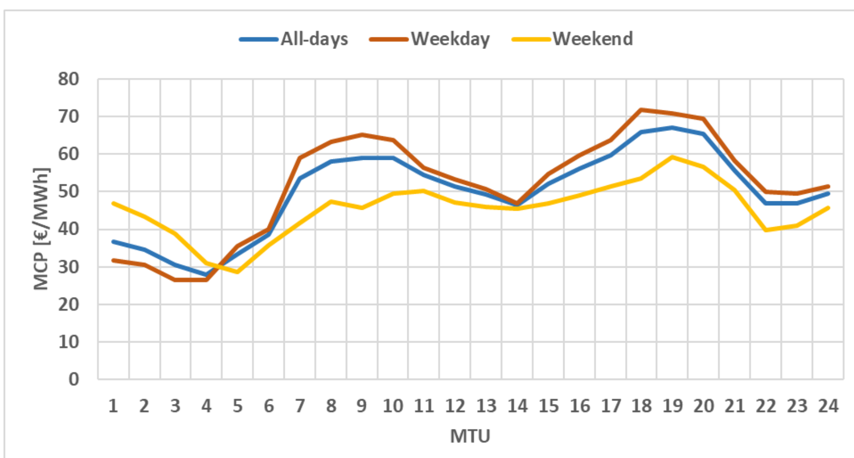
Figure 2.15. LIDA2 MCP Duration Curves – (a) November 2020; (b) December 2020; (c) January 2021



(a)



(b)



(c)

Figure 2.16. LIDA2 Representative Days – (a) November 2020; (b) December 2020; (c) January 2021

In Tables 2.10-2.12 the results of the statistics of LIDA2 MCP, are presented for November 2020, December 2020 and January 2021 respectively, as calculated based on equations $(2.1) - (2.4)$. More specifically, the results correspond to the average, minimum, maximum and the spread of MCP on a daily resolution analysis and presentation of the results.

Table 2.10. LIDA2 MCP Daily Statistics – November 2020

Date	Average Daily MCP [€/MWh]	Min Daily MCP [€/MWh]	Max Daily MCP [€/MWh]	Daily MCP Spread [€/MWh]
20201101	56.37	35.74	100.00	64.26
20201102	44.27	18.00	80.23	62.23
20201103	74.69	40.88	129.30	88.42
20201104	46.16	33.94	71.90	37.96
20201105	43.91	29.56	59.68	30.12
20201106	39.62	27.55	46.52	18.97
20201107	37.61	27.17	54.50	27.33
20201108	35.37	22.06	54.00	31.94
20201109	47.16	29.43	74.64	45.21
20201110	48.19	33.03	68.89	35.86
20201111	47.82	33.05	65.21	32.16
20201112	73.40	39.61	130.14	90.53
20201113	68.31	48.10	113.10	65.00
20201114	49.13	37.49	78.02	40.53
20201115	54.58	35.66	87.51	51.85
20201116	53.89	31.56	80.04	48.48
20201117	59.84	32.05	85.90	53.85
20201118	46.05	25.12	66.61	41.49
20201119	58.80	39.92	81.45	41.53
20201120	40.70	16.73	83.05	66.32
20201121	37.68	29.98	50.07	20.09
20201122	38.22	16.34	63.39	47.05
20201123	60.38	30.73	85.16	54.43
20201124	50.13	20.17	74.89	54.72
20201125	55.29	30.78	78.65	47.87
20201126	56.42	29.27	82.60	53.33
20201127	45.33	19.40	78.05	58.65
20201128	53.08	24.55	83.66	59.11
20201129	57.74	41.33	85.91	44.58
20201130	75.65	42.26	143.45	101.19

Table 2.11. LIDA2 MCP Daily Statistics – December 2020

Date	Average Daily MCP [€/MWh]	Min Daily MCP [€/MWh]	Max Daily MCP [€/MWh]	Daily MCP Spread [€/MWh]
20201201	55.00	0.09	90.71	90.62
20201202	110.96	45.91	238.33	192.42
20201203	96.79	39.84	150.02	110.18
20201204	75.23	20.00	116.27	96.27
20201205	62.08	20.00	100.68	80.68
20201206	51.57	33.56	76.02	42.46
20201207	64.71	10.43	99.00	88.57
20201208	72.56	42.29	110.01	67.72
20201209	65.43	20.05	104.00	83.95
20201210	62.94	22.28	97.70	75.42
20201211	62.66	37.37	102.46	65.09
20201212	50.51	39.90	65.23	25.33
20201213	42.65	19.42	78.72	59.30
20201214	76.50	42.77	90.74	47.97
20201215	74.23	19.00	146.49	127.49
20201216	53.48	3.70	99.60	95.90
20201217	132.28	68.80	200.00	131.20
20201218	83.49	4.74	119.80	115.06
20201219	40.01	20.00	62.10	42.10
20201220	49.96	42.37	66.28	23.91
20201221	79.81	43.55	120.00	76.45
20201222	32.82	7.10	75.02	67.92
20201223	31.34	-10.00	55.03	65.03
20201224	44.68	5.77	96.55	90.78
20201225	42.40	26.03	71.44	45.41
20201226	12.55	10.01	25.00	14.99
20201227	61.33	31.38	84.01	52.63
20201228	40.65	11.24	62.00	50.76
20201229	38.49	18.86	58.16	39.30
20201230	28.27	3.30	60.06	56.76
20201231	35.26	12.44	56.13	43.69

Table 2.12. LIDA2 MCP Daily Statistics – January 2021

Date	Average Daily MCP [€/MWh]	Min Daily MCP [€/MWh]	Max Daily MCP [€/MWh]	Daily MCP Spread [€/MWh]
20210101	39.84	3.89	60.61	56.72
20210102	33.92	-19.92	53.08	73.00
20210103	45.13	13.20	94.90	81.70
20210104	31.76	-1.00	68.24	69.24
20210105	51.31	17.57	69.32	51.75
20210106	18.75	7.92	48.87	40.95
20210107	41.25	9.53	70.41	60.88
20210108	58.42	20.75	83.90	63.15
20210109	33.35	6.49	66.71	60.22
20210110	43.94	6.78	58.99	52.21
20210111	49.48	1.00	72.15	71.15
20210112	52.54	20.00	73.64	53.64
20210113	62.93	47.27	90.00	42.73
20210114	57.30	5.08	95.89	90.81
20210115	60.44	4.30	97.92	93.62
20210116	50.76	41.00	66.40	25.40
20210117	69.22	35.73	110.99	75.26
20210118	88.63	27.21	137.16	109.95
20210119	65.81	9.60	95.90	86.30
20210120	37.34	6.00	84.05	78.05
20210121	54.76	16.95	77.63	60.68
20210122	52.80	30.89	70.39	39.50
20210123	45.42	19.24	57.00	37.76
20210124	41.02	25.00	49.97	24.97
20210125	47.57	5.00	91.97	86.97
20210126	55.62	29.32	79.84	50.52
20210127	48.16	4.30	100.60	96.30
20210128	64.72	45.51	93.71	48.20
20210129	52.84	35.41	72.84	37.43
20210130	49.61	29.61	92.40	62.79
20210131	42.33	24.15	61.93	37.78

2.1.4 Local Intra-Day Auction 3 (LIDA3)

The Table 2.13 includes the results of the monthly statistics of the LIDA3 MCP, which are also illustrated in Figure 2.17. The highest monthly average MCP resulted in November at 56.03€/MWh and the lowest one, resulted in January at 48.07€/MWh. For November, the minimum and maximum daily MCP were set at 9.71€/MWh and 102.80€/MWh respectively, resulting a spread of 93.09€/MWh. For December, the minimum and maximum MCP were set at 7.38€/MWh and 162.39€/MWh respectively, resulting a spread of 155.01€/MWh. For January, the minimum and maximum MCP were set at 11.78€/MWh and 77.99€/MWh respectively, resulting a spread of 66.20€/MWh.

The column "Spread" shows the volatility of MCP on a monthly basis, where the highest spread was resulted in December at 155.01€/MWh and the lowest spread resulted at 66.20€/MWh in January. Finally, the column "Average Daily Spread" shows the volatility of MPC on a daily basis for the respective month, where the highest spread was resulted in December at 63.77€/MWh and the lowest spread resulted in January at 49.94€/MWh.

Table 2.13. LIDA3 MCP Monthly Statistics

Month	Average [€/MWh]	Min [€/MWh]	Max [€/MWh]	Spread [€/MWh]	Average Daily Spread [€/MWh]
Nov 2020	56.03	9.71	102.80	93.09	53.31
Dec 2020	54.98	7.38	162.39	155.01	63.77
Jan 2021	48.07	11.78	77.99	66.20	49.94

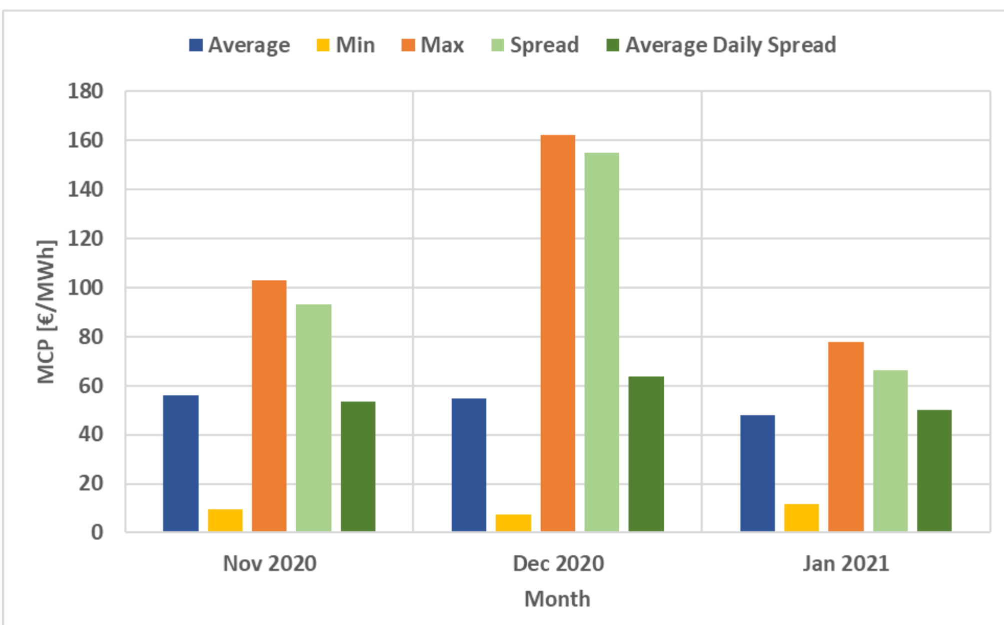


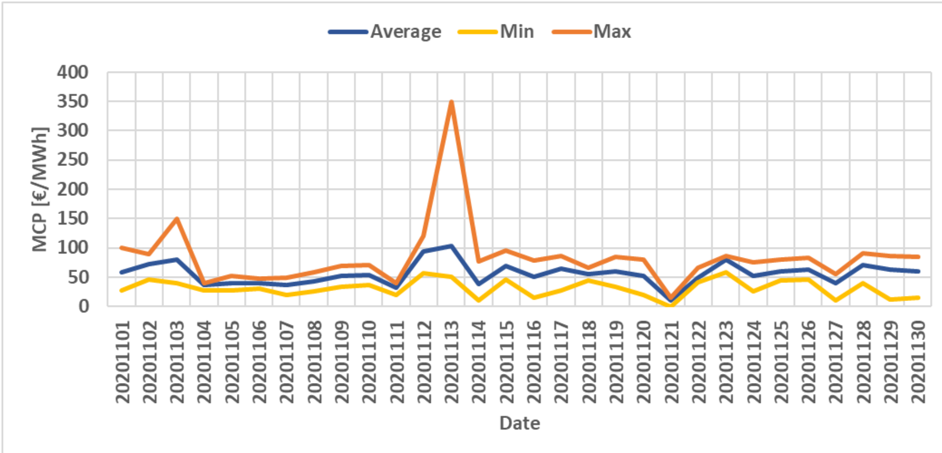
Figure 2.17. LIDA3 MCP Monthly Statistics

In Figures 2.18(a)-(c) the development of the daily average, minimum and maximum LIDA3 MCP are presented for November 2020 to January 2021 respectively. Regarding November, the minimum daily MCP was set at 9.71€/MWh on 21.11.2020 and the maximum daily MCP was set at 102.80€/MWh on 13.11.2020. The minimum hourly MCP was set at 0.00€/MWh on 21.11.2020 at MTU 24 and the maximum hourly MCP was set at 350.00€/MWh on 13.11.2020 at MTU 21. Regarding December, the minimum daily MCP was set at 7.38€/MWh on 27.12.2020 and the maximum daily MCP was set at 162.39€/MWh on 17.12.2020. The minimum hourly MCP was set at -16.09€/MWh on 27.12.2020 at MTU 24 and the maximum hourly MCP was set at 250.00€/MWh on 17.12.2020 at MTU 19. Regarding January, the minimum daily MCP was set 11.78€/MWh on 06.01.2021 and the maximum daily MCP was set at 77.99€/MWh on 13.01.2021. The minimum hourly MCP was set at 0.01€/MWh on 01.01.2021 at MTU 14 and the maximum hourly MCP was set at 115.00€/MWh on 18.01.2021 at MTU 20.

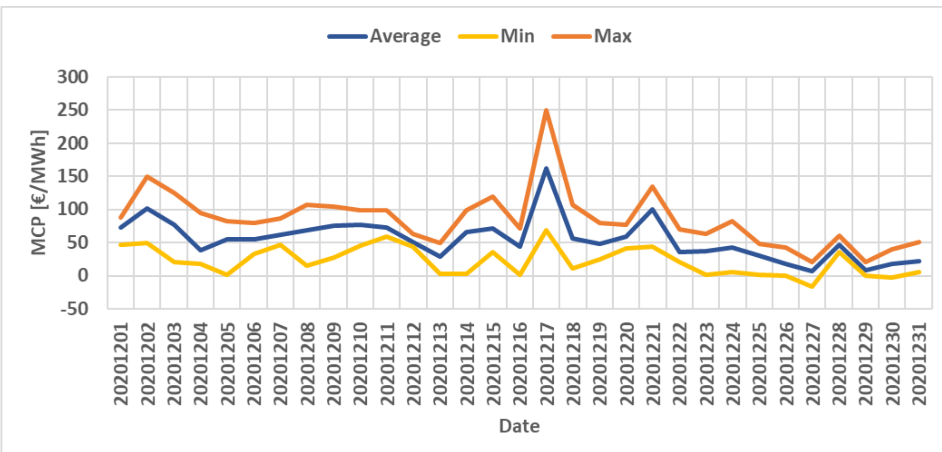
In Figures 2.19(a)-(c) the development of the daily spreads of LIDA3 MCP are presented for November 2020 to January 2021 respectively as well as the trend line of the respective month. Regarding November, the lowest spread was resulted at 11.22€/MWh on 04.11.2020 and the highest one was resulted at 299.64€/MWh on 13.11.2020. Regarding December, the lowest spread was resulted at 19.96€/MWh on 12.12.2020 and the highest one was resulted at 181.40€/MWh on 17.12.2020. Regarding January, the lowest spread was resulted at 3.81€/MWh on 06.01.2021 and the highest one was resulted at 104.49€/MWh on 28.01.2021.

In Figures 2.20(a)-(c) the monthly duration curves of LIDA3 MCP results are presented for November 2020 to January 2021 respectively. The vertical axis corresponds to the MCP price and the horizontal axis corresponds to the percentage of MTUs within a month, for which the resulted MCP was higher compared to the respective price of the vertical axis. Regarding November, the hourly MCP was set above 90€/MWh, 80€/MWh and 60€/MWh at a percentage of 7.22%, 15.56% and 36.94% respectively. Also, the hourly MCP for November was set below 50€/MWh 40€/MWh and 30€/MWh, at a percentage of 45.83%, 23.61% and 10.56% respectively. Regarding December, the hourly MCP was set above 90€/MWh, 80€/MWh and 60€/MWh at a percentage of 13.48%, 22.64% and 38.27% respectively. Also, the hourly MCP for December was set below 50€/MWh 40€/MWh and 30€/MWh, at a percentage of 50.94%, 36.39% and 24.26% respectively. It is worth noting that on 29.12.2020 the MCP was set at 0.00€/MWh for four MTUs and also on 27.12.2020 & 30.12.2020 the MCP was set at negative prices twice for each day respectively. Regarding January, the hourly MCP was set above 90€/MWh, 80€/MWh and 60€/MWh at a percentage of 4.03%, 8.60% and 28.49% respectively. Also, the hourly MCP for January was set below 50€/MWh 40€/MWh and 30€/MWh, at a percentage of 54.57%, 30.65% and 22.31% respectively. It is worth noting that the hourly MCP was set below 10€/MWh at a percentage of 2.96%.

In Figures 2.21(a)-(c) the monthly representative days are presented for November 2020 to January 2021 respectively, and more specifically for each month, three different representative daily curves are formulated for the weekdays (*weekday*), non-weekdays (*weekend*) and for all days (*all-days*). Regarding all three months under study, for all the MTUs (13-24), the weekend curve is lower than the other two curves. Especially for MTUs 21-24 the deviation between the weekday curves and the all-days curves is minimal.



(a)



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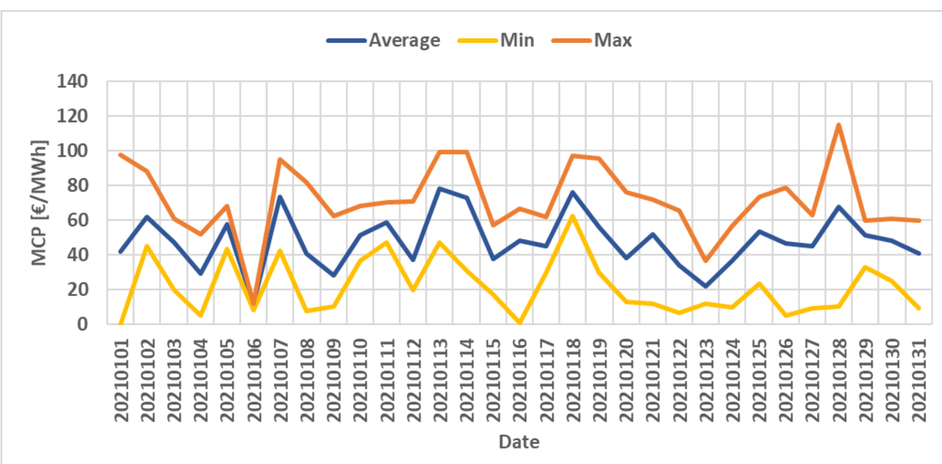
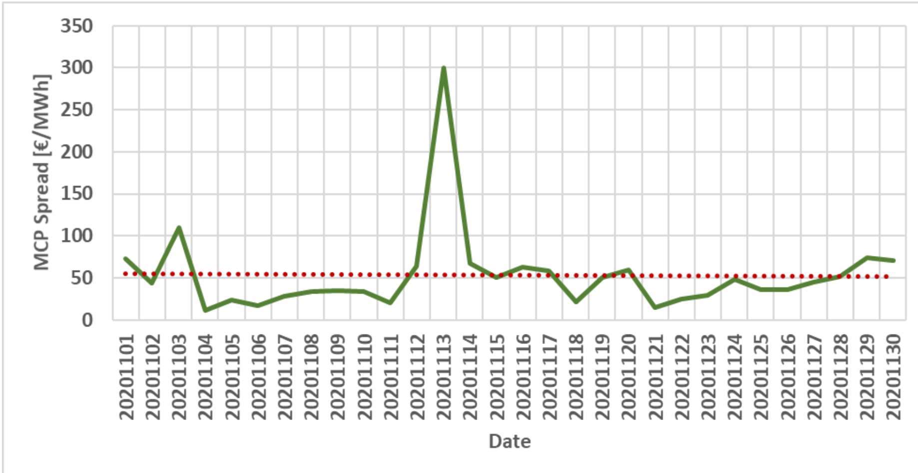
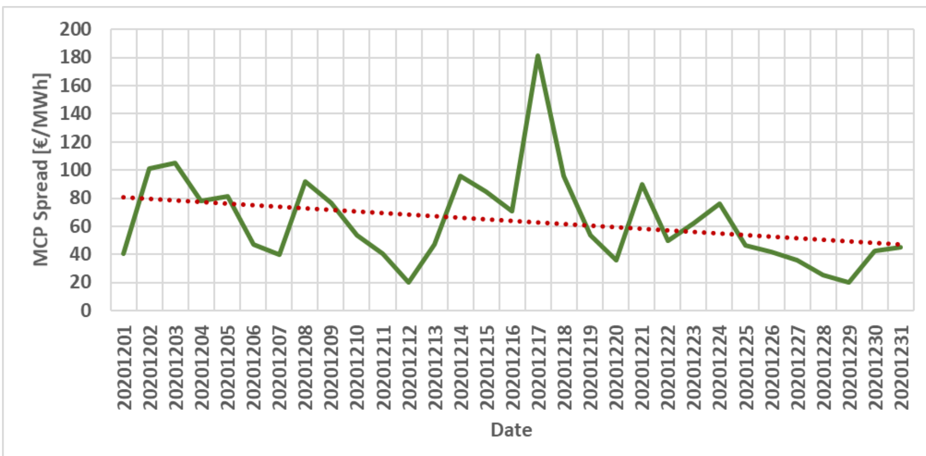


(c)

Figure 2.18. LIDA3 MCP Daily Statistics – (a) November 2020; (b) December 2020; (c) January 2021



(a)



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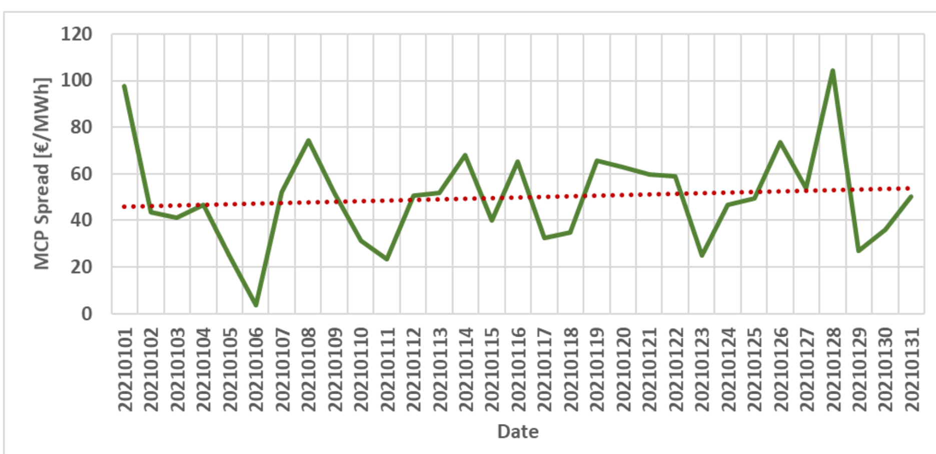
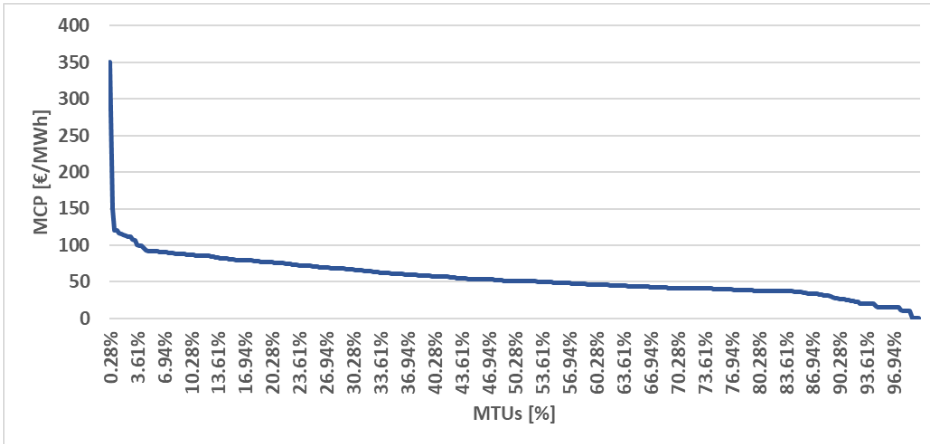
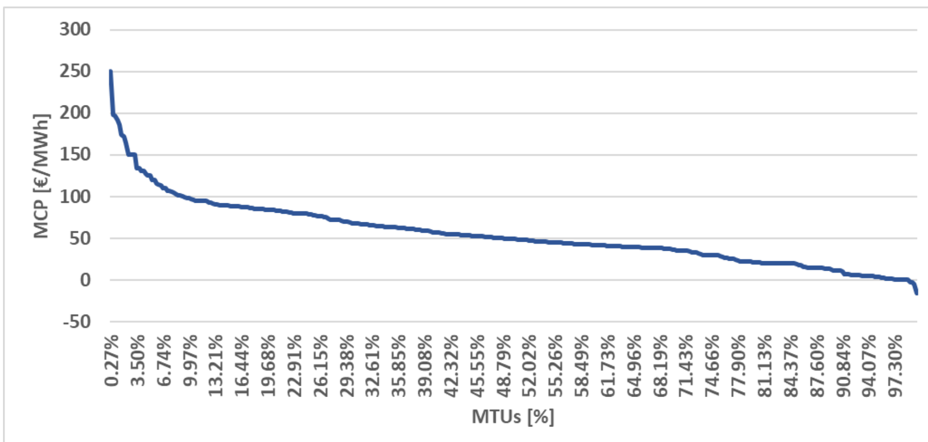


(c)

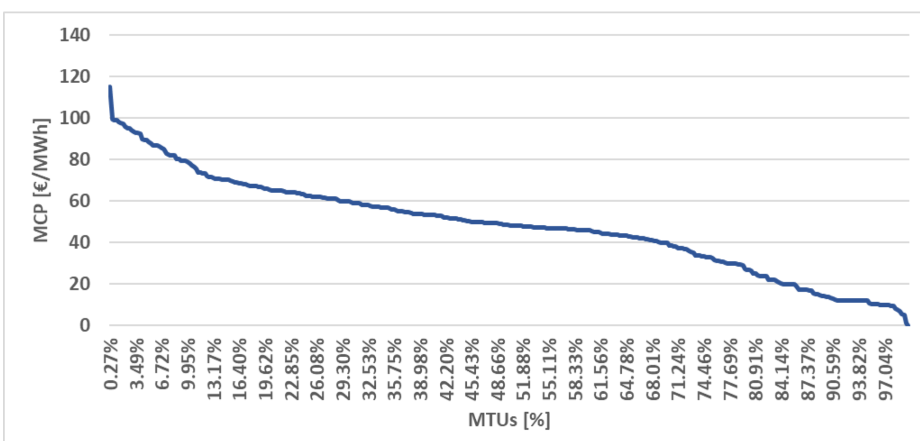
Figure 2.19. LIDA3 MCP Daily Spreads – (a) November 2020; (b) December 2020; (c) January 2021



(a)

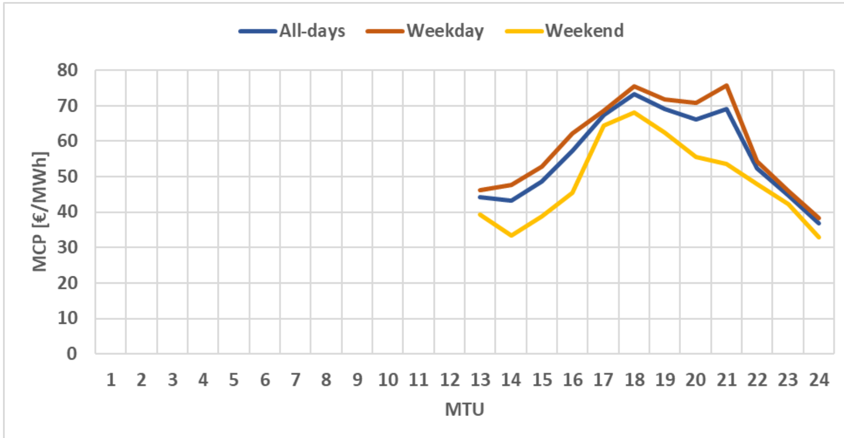


(b)

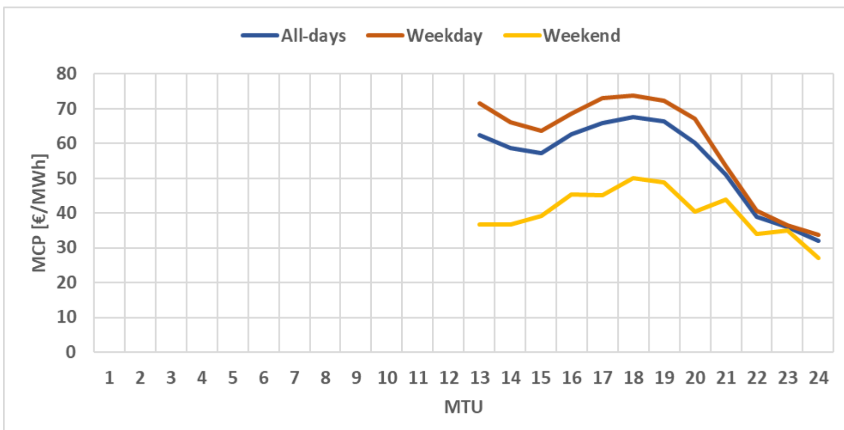


(c)

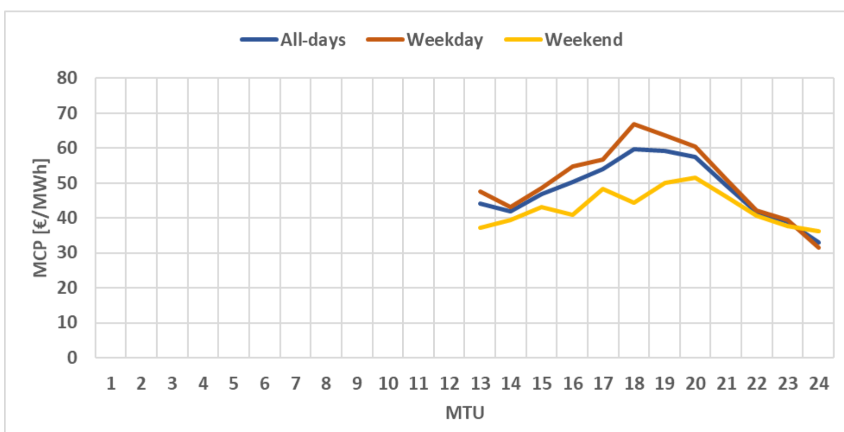
Figure 2.20. LIDA3 MCP Duration Curves – (a) November 2020; (b) December 2020; (c) January 2021



(a)



(b)



(c)

Figure 2.21. LIDA3 Representative Days – (a) November 2020; (b) December 2020; (c) January 2021

In Tables 2.14-2.16 the results of the statistics of LIDA3 MCP, are presented for November 2020, December 2020 and January 2021 respectively, as calculated based on equations $(2.1) - (2.4)$. More specifically, the results correspond to the average, minimum, maximum and the spread of MCP on a daily resolution analysis and presentation of the results.

Table 2.14. LIDA3 MCP Daily Statistics – November 2020

Date	Average Daily MCP [€/MWh]	Min Daily MCP [€/MWh]	Max Daily MCP [€/MWh]	Daily MCP Spread [€/MWh]
20201101	58.51	27.01	100.30	73.29
20201102	72.66	46.25	89.92	43.67
20201103	79.57	40.25	149.90	109.65
20201104	36.65	28.06	39.28	11.22
20201105	40.28	27.35	51.78	24.43
20201106	40.48	30.75	47.63	16.88
20201107	36.00	20.00	48.59	28.59
20201108	43.56	25.50	59.00	33.50
20201109	52.54	34.16	69.80	35.64
20201110	53.48	36.95	70.88	33.93
20201111	31.68	20.00	40.21	20.21
20201112	93.90	56.43	120.08	63.65
20201113	102.80	50.36	350.00	299.64
20201114	38.94	10.00	77.75	67.75
20201115	70.04	45.63	95.97	50.34
20201116	50.68	15.00	78.48	63.48
20201117	64.11	26.76	85.90	59.14
20201118	55.18	45.00	66.72	21.72
20201119	60.60	33.64	84.57	50.93
20201120	52.17	20.00	80.00	60.00
20201121	9.71	0.00	15.00	15.00
20201122	48.82	40.86	65.53	24.67
20201123	80.03	57.72	86.79	29.07
20201124	52.14	26.38	75.11	48.73
20201125	59.30	44.13	80.26	36.13
20201126	63.85	46.78	82.60	35.82
20201127	39.96	10.00	55.09	45.09
20201128	70.41	39.15	91.60	52.45
20201129	62.35	11.65	85.91	74.26
20201130	60.64	15.00	85.47	70.47

Table 2.15. LIDA3 MCP Daily Statistics – December 2020

Date	Average Daily MCP [€/MWh]	Min Daily MCP [€/MWh]	Max Daily MCP [€/MWh]	Daily MCP Spread [€/MWh]
20201201	72.31	47.28	88.13	40.85
20201202	101.70	49.17	150.00	100.83
20201203	76.50	20.00	125.12	105.12
20201204	38.30	17.26	95.26	78.00
20201205	54.28	1.55	82.84	81.29
20201206	55.26	33.07	79.90	46.83
20201207	61.31	46.55	86.60	40.05
20201208	68.03	15.00	106.99	91.99
20201209	75.82	27.03	104.10	77.07
20201210	76.84	44.75	98.20	53.45
20201211	73.37	58.97	99.54	40.57
20201212	50.86	43.27	63.23	19.96
20201213	29.41	2.26	49.13	46.87
20201214	66.46	2.38	98.23	95.85
20201215	71.72	35.33	119.90	84.57
20201216	43.54	1.00	71.80	70.80
20201217	162.39	68.60	250.00	181.40
20201218	56.83	11.18	107.10	95.92
20201219	47.54	25.19	79.21	54.02
20201220	59.05	41.62	77.25	35.63
20201221	99.89	44.14	134.29	90.15
20201222	35.53	20.00	70.05	50.05
20201223	36.63	1.00	62.95	61.95
20201224	43.16	5.77	81.99	76.22
20201225	30.68	1.23	47.66	46.43
20201226	17.76	0.01	41.99	41.98
20201227	7.38	-16.09	20.00	36.09
20201228	46.09	35.28	60.44	25.16
20201229	7.59	0.00	20.00	20.00
20201230	17.28	-2.81	39.90	42.71
20201231	22.14	5.49	50.58	45.09

Table 2.16. LIDA3 MCP Daily Statistics – January 2021

Date	Average Daily MCP [€/MWh]	Min Daily MCP [€/MWh]	Max Daily MCP [€/MWh]	Daily MCP Spread [€/MWh]
20210101	41.84	0.01	97.52	97.51
20210102	61.78	44.92	88.35	43.43
20210103	47.42	20.00	61.09	41.09
20210104	29.28	5.32	52.02	46.70
20210105	57.54	43.49	68.32	24.83
20210106	11.78	8.29	12.10	3.81
20210107	73.39	42.54	94.89	52.35
20210108	41.13	7.51	81.81	74.30
20210109	28.25	10.35	62.31	51.96
20210110	51.59	36.79	68.14	31.35
20210111	58.55	47.06	70.37	23.31
20210112	37.40	20.10	70.64	50.54
20210113	77.99	47.12	99.14	52.02
20210114	72.97	30.81	99.01	68.20
20210115	37.95	17.00	57.04	40.04
20210116	48.47	1.01	66.40	65.39
20210117	45.09	29.81	62.14	32.33
20210118	75.97	62.33	97.16	34.83
20210119	56.09	29.96	95.79	65.83
20210120	38.38	13.13	76.09	62.96
20210121	52.16	11.95	71.69	59.74
20210122	33.87	6.63	65.68	59.05
20210123	21.73	11.96	36.77	24.81
20210124	36.67	9.95	56.67	46.72
20210125	53.73	23.73	73.26	49.53
20210126	46.45	5.00	78.77	73.77
20210127	44.86	9.34	63.17	53.83
20210128	67.84	10.51	115.00	104.49
20210129	51.37	32.84	59.78	26.94
20210130	48.08	25.00	61.00	36.00
20210131	40.72	9.40	59.74	50.34

2.2 European Energy Exchange (eex) Standardized Indices for Power Futures

In the present section the standardized indices for power futures of the European Energy Exchange (eex) are calculated for the first three months of the Greek Power Market under the EU Target Model implementation, according to the official methodologies [59], which are presented also in Table 2.17.

Table 2.17. Methodologies for European Energy Exchange (eex) Daily Indices for Power Futures [59]

Index	Methodology
Base Day Index	Average of all auction prices of traded day-ahead contracts for the respective market area for the hours between 00:00 - 24:00 (CE(S)T) and the respective day (Monday to Sunday).
Base Weekend Index	Average of all auction prices of traded day-ahead contracts for the respective market area for the hours between 00:00 - 24:00 (CE(S)T) and the respective weekend (Saturday to Sunday).
Base Week Index	Average of all auction prices of traded day-ahead contracts for the respective market area for the hours between 00:00 - 24:00 (CE(S)T) and the respective week (Monday to Sunday).
Base Month Index	Average of all auction prices of traded day-ahead contracts for the respective market area for the hours between 00:00 - 24:00 (CE(S)T) for all days (Monday to Sunday) of the respective month.
Peak Dat Index	Average of all auction prices of traded day-ahead contracts for the respective market area for the hours between 08:00 - 20:00 (CE(S)T) and the respective day (Monday to Sunday).
Peak Weekend Index	Average of all auction prices of traded day-ahead contracts for the respective market area for the hours between 08:00 - 20:00 (CE(S)T) and the respective weekend (Saturday to Sunday).
Peak Week Index	Average of all auction prices of traded day-ahead contracts for the respective market area for the hours between 08:00 - 20:00 (CE(S)T) and the respective week (Monday to Friday).
Peak Month Index	Average of all auction prices of traded day-ahead contracts for the respective market area for the hours between 08:00 - 20:00 (CE(S)T) for all days Monday to Friday of the respective month.
Off-Peak Month Index	Average of all auction prices of traded day-ahead contracts for the respective market area for the hours between 00:00 - 08:00 (CE(S)T) and 20:00 - 24:00 (CE(S)T) for all days Monday through Friday as well as the hours between 00:00 - 24:00. (CE(S)T) at for the days Saturday and Sunday of the respective month.

In Table 2.18 the results of the calculations regarding the Power Future indices are presented for the Base Day Index and the Peak Day index in a daily resolution for the period under study (01.11.2020-31.01.2021) and the corresponding illustration of the results is shown in Figure 2.22.

Table 2.18. European Energy Exchange (eex) Daily Indices for Power Futures

DATE	Base Day Index [€/MWh]	Peak Day Index [€/MWh]	DATE	Base Day Index [€/MWh]	Peak Day Index [€/MWh]	DATE	Base Day Index [€/MWh]	Peak Day Index [€/MWh]
20201101	53.56	51.28	20201201	52.89	74.25	20210101	45.58	45.98
20201102	60.99	66.53	20201202	74.00	92.56	20210102	47.11	51.70
20201103	56.01	63.47	20201203	90.69	123.90	20210103	43.47	48.69
20201104	47.48	52.16	20201204	77.27	104.40	20210104	47.46	60.44
20201105	43.25	47.35	20201205	60.46	72.97	20210105	50.89	61.55
20201106	40.38	44.45	20201206	48.09	55.08	20210106	52.84	53.26
20201107	37.78	40.00	20201207	53.69	70.56	20210107	44.64	56.02
20201108	36.29	40.83	20201208	71.17	87.86	20210108	55.72	72.66
20201109	47.43	55.90	20201209	71.94	96.44	20210109	51.64	64.62
20201110	48.49	54.52	20201210	63.09	85.19	20210110	51.96	51.64
20201111	44.80	50.63	20201211	56.90	68.97	20210111	51.65	58.73
20201112	68.09	80.58	20201212	48.63	52.86	20210112	52.47	67.64
20201113	64.75	71.44	20201213	44.01	47.81	20210113	67.76	76.97
20201114	51.20	57.13	20201214	46.13	55.88	20210114	46.16	67.25
20201115	54.31	59.02	20201215	64.90	89.43	20210115	63.69	77.01
20201116	60.44	72.39	20201216	80.36	101.45	20210116	50.96	54.89
20201117	58.87	73.49	20201217	93.78	124.55	20210117	53.98	65.42
20201118	47.59	54.91	20201218	82.31	106.32	20210118	66.95	77.79
20201119	46.26	52.32	20201219	62.33	73.70	20210119	71.73	83.13
20201120	43.64	51.34	20201220	47.12	53.70	20210120	63.45	70.52
20201121	41.11	45.55	20201221	62.88	80.39	20210121	59.68	66.60
20201122	42.98	49.67	20201222	82.02	105.89	20210122	56.05	64.87
20201123	68.36	76.95	20201223	62.60	75.94	20210123	47.24	53.11
20201124	52.87	60.00	20201224	43.40	50.27	20210124	43.28	48.90
20201125	56.45	65.52	20201225	41.83	43.87	20210125	45.70	51.52
20201126	56.12	64.86	20201226	37.74	43.32	20210126	49.53	47.99
20201127	72.01	79.18	20201227	35.75	44.35	20210127	45.39	54.95
20201128	60.18	69.96	20201228	40.38	46.95	20210128	59.98	66.93
20201129	58.14	65.23	20201229	43.37	50.33	20210129	52.13	60.18
20201130	59.84	71.74	20201230	42.05	49.20	20210130	46.75	52.05
			20201231	45.19	52.15	20210131	42.28	47.64

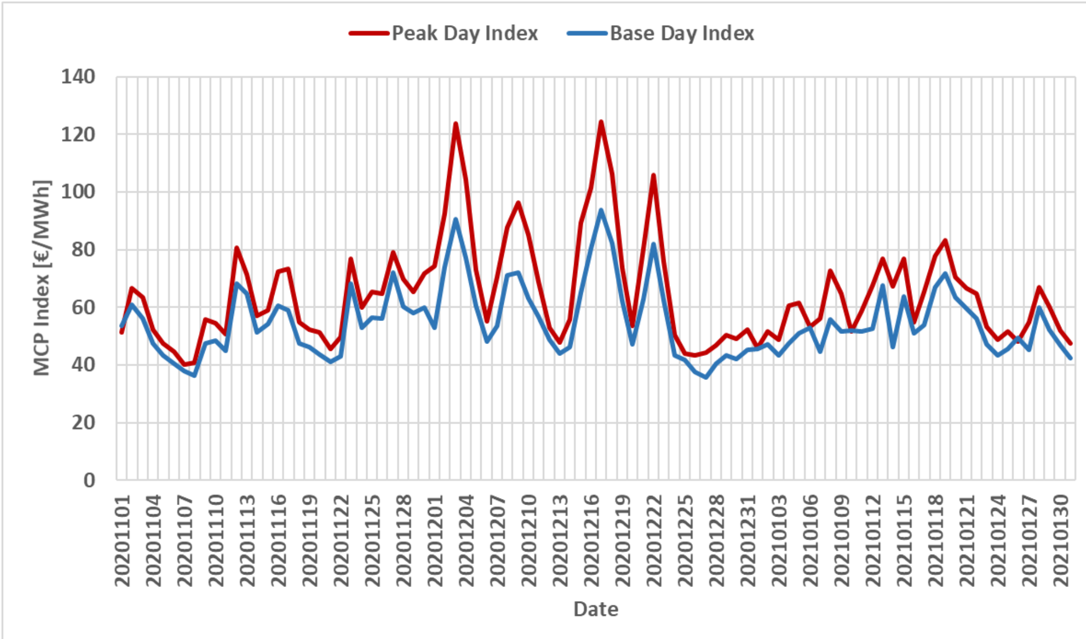


Figure 2.22. European Energy Exchange (eex) Daily Indices for Power Futures

In Table 2.19 the analytical results of the calculations regarding the weekly indices are presented for the period under study (01.11.2020-31.01.2021) in a weekly resolution and the corresponding illustration is shown in Figure 2.23 below.

Table 2.19. European Energy Exchange (eex) Weekly Indices for Power Futures

week	Base Weekend Index [€/MWh]	Peak Weekend Index [€/MWh]	Base Week Index [€/MWh]	Peak Week Index [€/MWh]
0	53.56	51.28	53.56	-
1	37.03	40.41	46.03	54.79
2	52.76	58.07	54.15	62.61
3	42.05	47.61	48.70	60.89
4	59.16	67.60	60.59	69.30
5	54.27	64.02	66.18	93.37
6	46.32	50.33	58.49	81.80
7	54.72	63.70	68.13	95.53
8	36.74	43.84	52.32	71.27
9	45.29	50.19	43.88	48.92
10	51.80	58.13	50.74	60.78
11	52.47	60.15	55.24	69.52
12	45.26	51.01	58.34	72.58
13	44.51	49.84	48.82	56.31

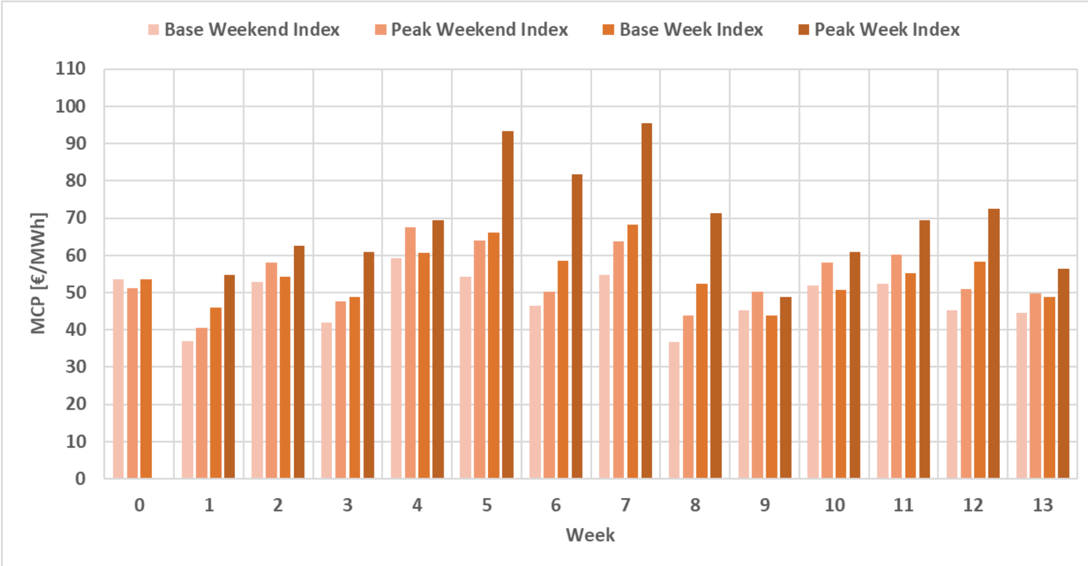


Figure 2.23. European Energy Exchange (eex) Weekly Indices for Power Futures

The results of the calculations regarding the monthly indices are presented in Table 2.20 and the corresponding illustration is shown in Figure 2.24.

Table 2.20. European Energy Exchange (eex) Monthly Indices for Power Futures

Month	Base Month Index [€/MWh]	Peak Month Index [€/MWh]	Off-Peak Month Index[€/MWh]
Nov 2020	52.66	62.37	47.43
Dec 2020	58.93	79.86	46.60
Jan 2021	52.52	63.90	46.69

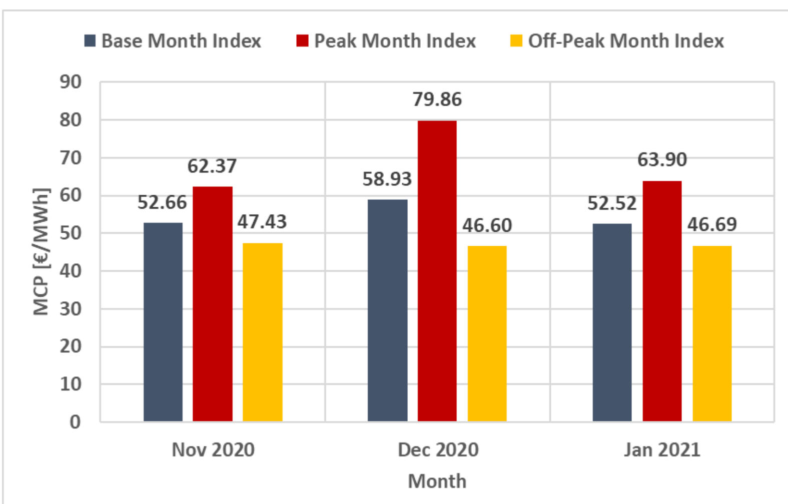


Figure 2.24. European Energy Exchange (eex) Monthly Indices for Power Futures

2.3 DAM Energy Mix

On the supply side the day-ahead market mix comprises of generation by Lignite, Natural Gas, Hydro, Renewables, which are mainly solar and wind power, and Imports through Cross-Border electricity Trading (CBT). The RES & GO Operator (*DAPEEP*), represents the majority share (aprox.75%) of the RES production and submits Priority-Price Taking Orders to the ETSS in order to participate in the energy mix of the Day-Ahead Market. The rest of RES generation is represented by RES aggregators. Finally, the thermal generation is owned by 4 market participants and the incumbent is the only owner of the Large Hydro production [60].

On the demand side of the Day-Ahead Market the mix comprises of LV load, MV, Load, HV Load, Pumping, System Losses and Exports through cross-border electricity trading (CBT). The System Losses are submitted to the ETSS through Priority Price Taking Orders by the TSO. Apart from the incumbent company, which is the only one that represents HV and Pumping Load, there are 25 independent suppliers, 9 of which represent a portfolio of LV and MV load that corresponds to a market share greater than 1% [60].

2.3.1 Supply Mix

In the Greek Power Market, the installed capacity comprises of 14 Lignite plants with total registered capacity of 3,903.9MW, 14 natural gas plants with total registered capacity of 5,211.3MW and 18 hydro plants with total registered capacity of 3,170.7MW [60]. The registered installed capacity of RES is 7,147MW in November, 7,233MW in December and 7,334MW in January [61]. In Table 2.21 are presented the monthly volumes in GWh per type of generation of the DAM supply mix for the three months under study, as well as the corresponding monthly average MCP.

Regarding the Supply mix, as it is shown in Figure 2.25, the share of RES equals to 24% in December, which is the lowest between the three months under study, where the respective share was 32% and 28% in November and January respectively. Also, the low penetration of RES in December has as a consequence a higher share of Lignite generation (16%) instead of 13% and 12% in November and January respectively. Accordingly, the Natural Gas generation is higher in December with a share of 42% instead of 40% and 38% in November and January respectively. The share of imports was increased in December at 15% instead of 13% and 10% in November and January respectively. According to the aforementioned shares per type of supply in the three months under study, it is shown that the higher shares of thermal generation have as a result a higher MCP, whereas the higher shares of “greener” generation (i.e., RES and Hydro) correspond to lower MCP. The combination of RES and Hydro counts for 41% of share in the supply mix of January instead of 34% and 26% in November and December respectively, and it is worth highlighting, that the monthly average MCP is lower as the generation share of the combination of RES and Hydro increases. This is also illustrated in Figure 2.26 where, the development of the supply mix of the Day-Ahead Market is presented graphically on a daily resolution, in parallel with the MCP development.

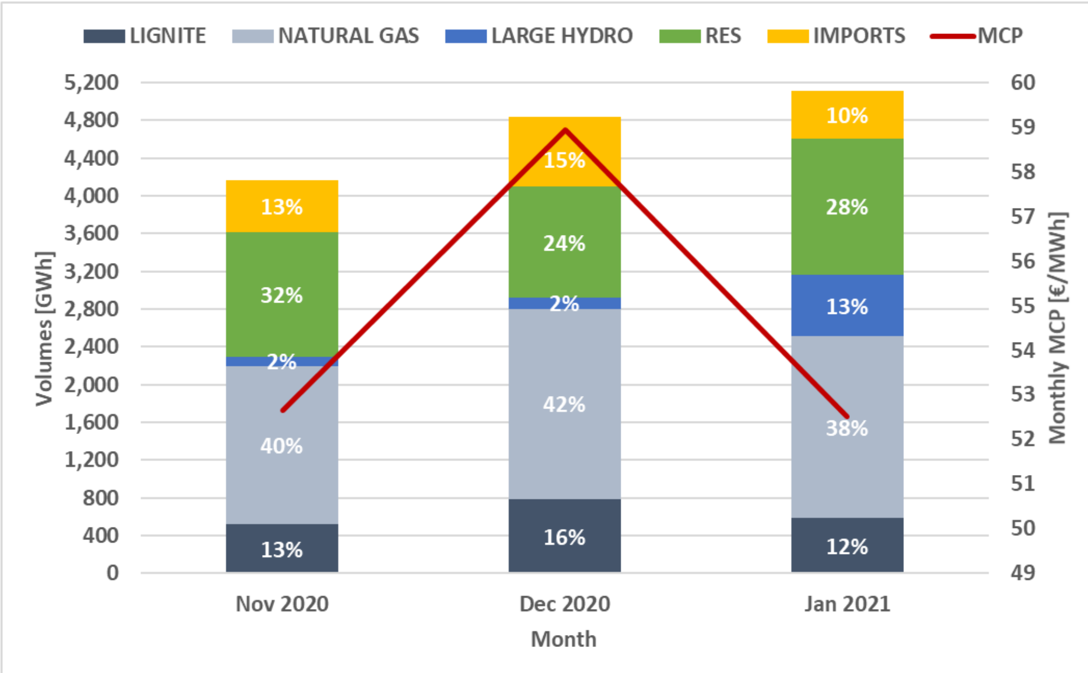


Figure 2.25. Monthly Supply Mix from November 2020 to January 2021

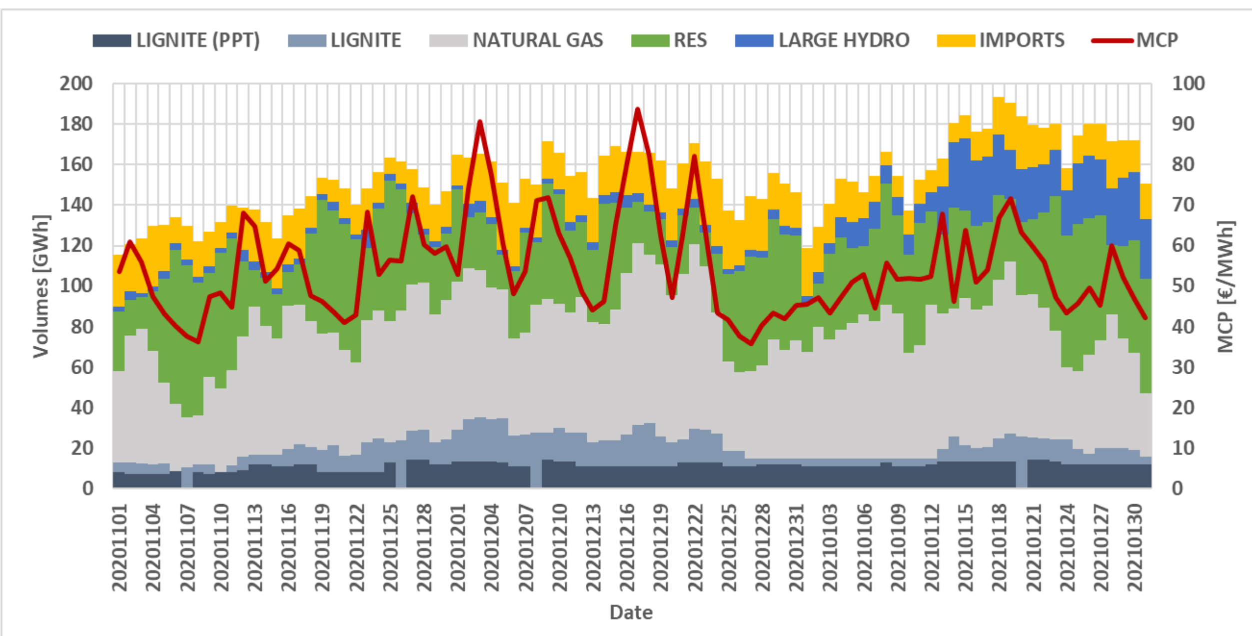


Figure 2.26. Daily Supply Mix from 01.11.2020 to 31.01.2021

Table 2.21. Monthly Supply Mix from November 2020 to January 2021

MONTH	LIGNITE [GWh]	NATURAL GAS [GWh]	LARGE HYDRO [GWh]	RES [GWh]	IMPORTS [GWh]	TOTAL [GWh]	MCP [€/MWh]
Nov 2020	526	1674	100	1315	556	4172	52.66
Dec 2020	792	2014	114	1180	740	4840	58.93
Jan 2021	593	1917	657	1445	497	5109	52.52

Focusing on the lignite generation that is illustrated separately in Figure 2.27, this is distinguished between the volumes that participate in the supply mix as settled in the Forward Market, which participate in the DAM through the submission of PPT Orders and correspond to the quantities traded in the Forward Market with the obligation of physical delivery on day D, and the volumes that participate in the DAM supply mix according to the Day-Ahead bidding prices and the MCP. As it is shown in Figures 2.26 and more detailed in Figure 2.27, in December, the volumes of lignite generation that participate in the market based on the Day-Ahead biding prices, are quite higher than the volumes that participate in the DAM through PPT Orders, which is also reflected in the MCP.

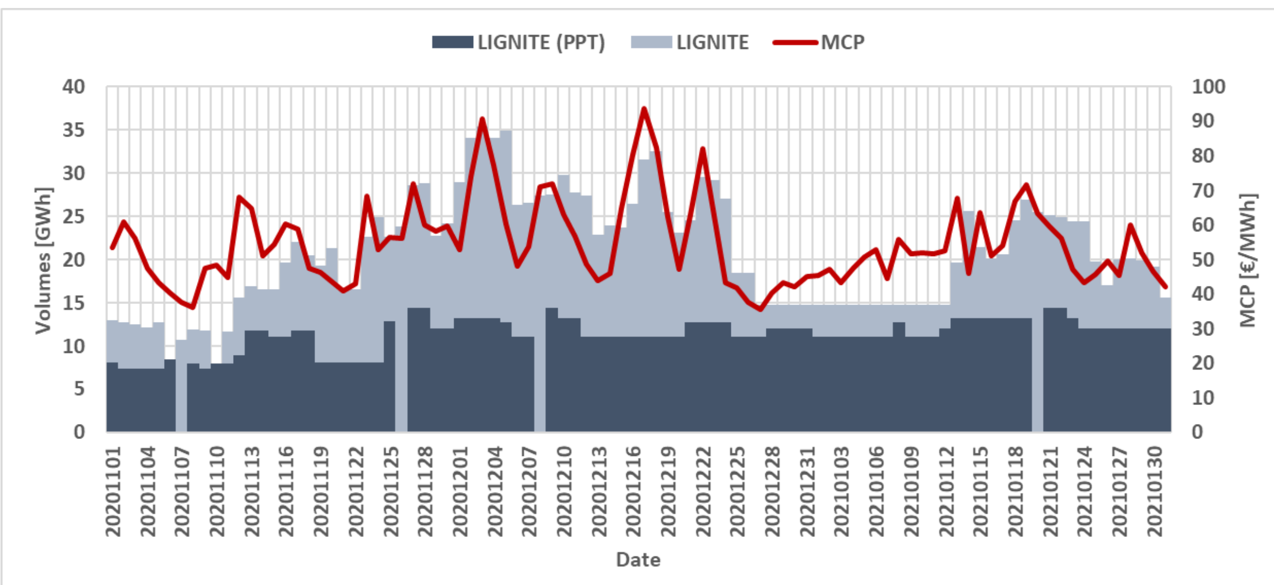


Figure 2.27. Lignite Production (Marketed and PPT) from 01.11.2020 to 31.01.2021

The generation developments of RES and Hydro are presented in Figures 2.28 and 2.29 respectively, for better presentation of the correlation compared to the MCP. As it is shown in Figure 2.28 an increased share of RES generation in the supply mix corresponds to lower MCP and vice versa. Furthermore, during the high penetration of Hydro generation the MCP is appeared to be in a lower level as shown in Figure 2.29.

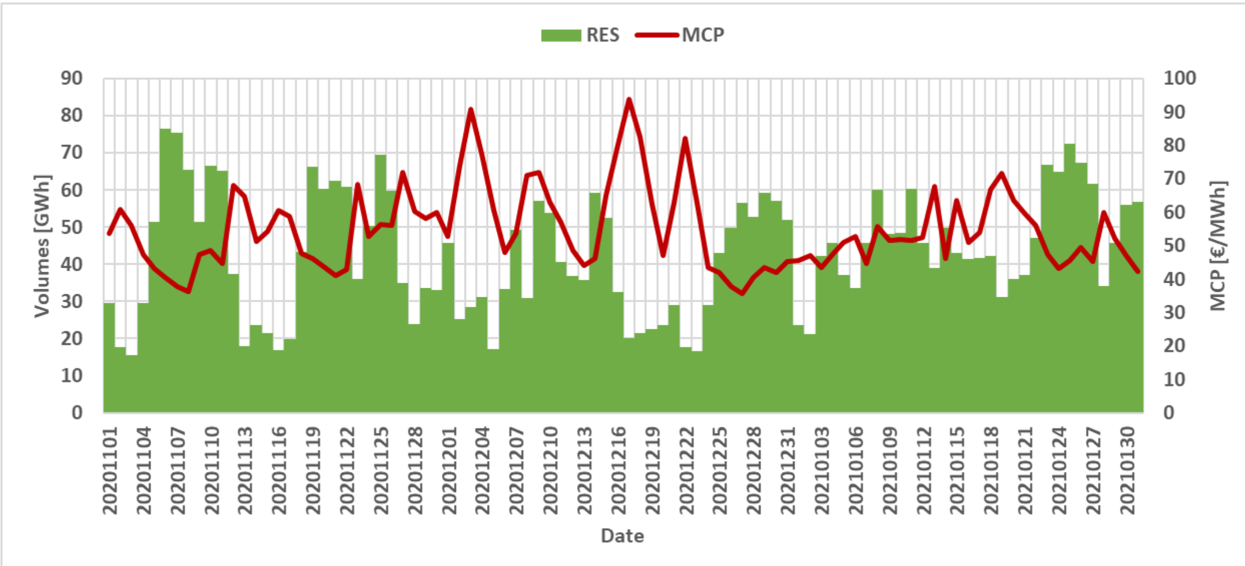


Figure 2.28. Renewables Production from 01.11.2020 to 31.01.2021

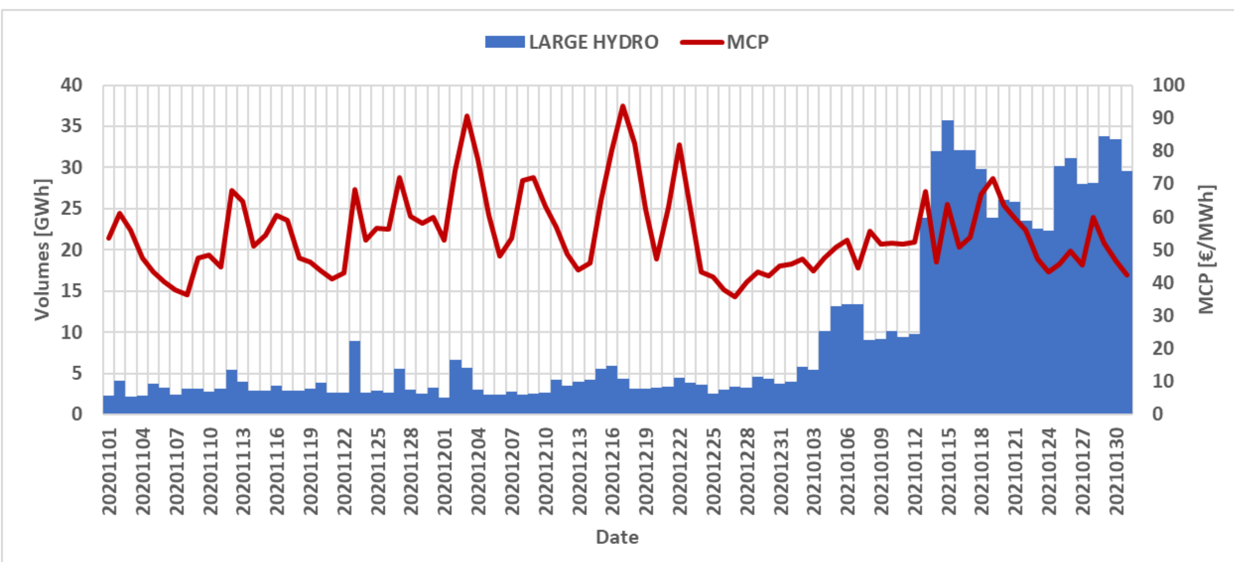


Figure 2.29. Large Hydro Production from 01.11.2020 to 31.01.2021

2.3.2 Demand Mix

The monthly demand mix is presented in Table 2.22 and illustrated in Figure 2.30. The demand mix comprises of the domestic load, the pumping needs of the hydro plants, the system losses and the exports. The domestic load is further distinguished into Low Voltage Load (LV Load), Mean Voltage Load (MV Load) and High Voltage (HV Load). As shown in Figure 2.30, the highest share corresponds to the LV Load at a steady percentage of 57% for the three months under study. The second largest share corresponds to the MV Load at the percentages of 19%, 16% and 15% for November, December and January, respectively. The share of HV Load accounts for 16% in November, 14% in December and 14% in January. The exporting quantities correspond to 5% in November, 10% in December and 12% in January, showing an increase from month to month. The pumping needs are a minimal component in the total demand mix and the system losses account for 2% of the total demand mix.

Table 2.22. Monthly Demand Mix from November 2020 to January 2021

MONTH	HV LOAD [GWh]	MV LOAD [GWh]	LV LOAD [GWh]	PUMP [GWh]	SYSTEM LOSSES [GWh]	EXPORTS [GWh]	TOTAL [GWh]	MCP [€/MWh]
Nov 2020	674	797	2392	11	93	205	4172	52.66
Dec 2020	683	791	2753	37	102	474	4840	58.93
Janu2021	704	787	2904	9	103	601	5109	52.52

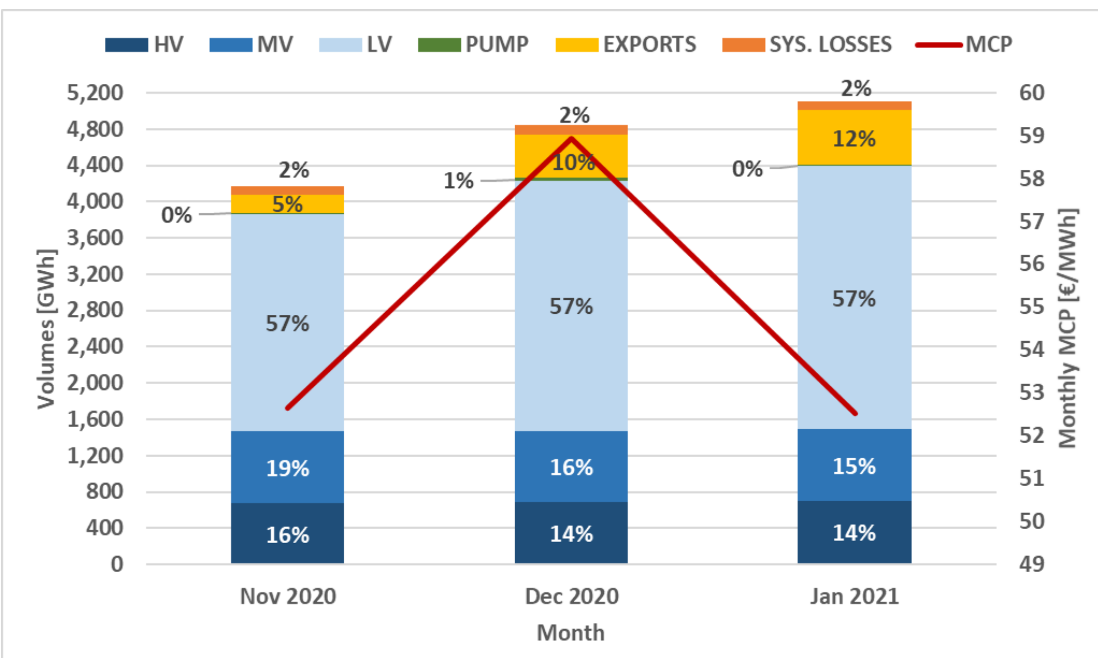


Figure 2.30. Monthly Demand Mix from November 2020 to January 2021

In Figure 2.31 the demand mix is illustrated in a daily resolution considering also the MCP development in the same illustration, where it is shown that a decrease in the total demand corresponds to a decrease in the MCP and vice versa, without prejudice to the generation mix.

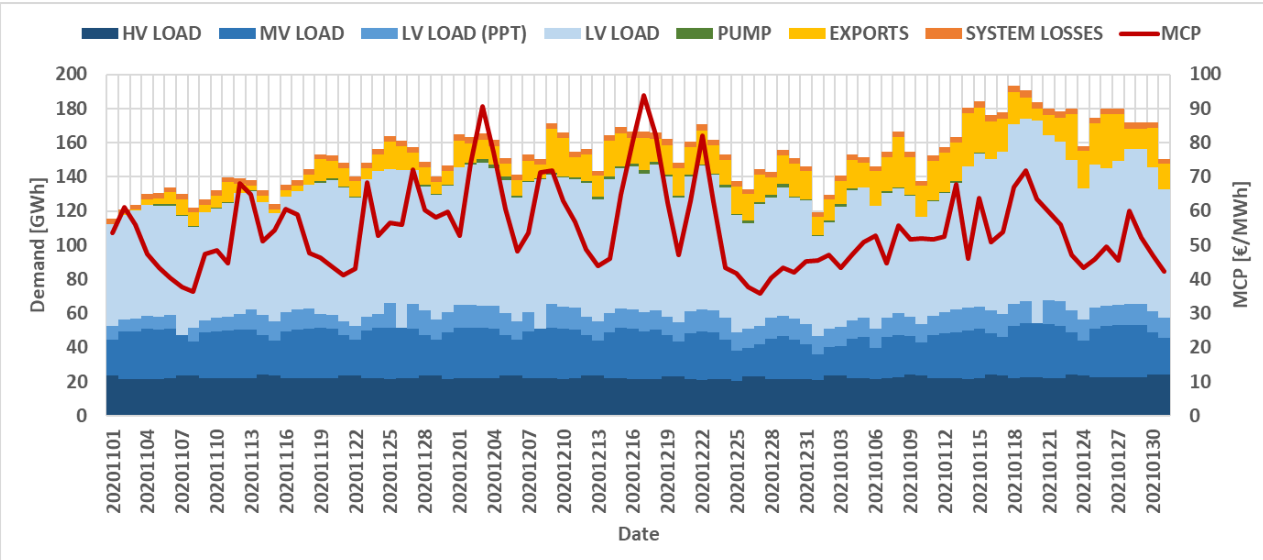


Figure 2.31. Daily Demand Mix from 01.11.2020 to 31.01.2021

2.3.2.1 LOAD Representative Days

In the present section the representative days of the load profiles are presented discretely for Low Voltage (LV LOAD), Mean Voltage (MV LOAD), High Voltage (HV LOAD) and Total (LV+MV+HV). For each type of load, three representative consumption curves are formulated per month, based on equations (2.13) – (2.15).

$$LOAD_{weekday}^{mtu,month} = \frac{1}{count\_of\_weekdays} \sum_{day=1}^{count\_of\_weekdays} LOAD_{day}^{mtu} \quad (2.13)$$

$$LOAD_{weekend}^{mtu,month} = \frac{1}{count\_of\_non\_weekdays} \sum_{day=1}^{count\_of\_non\_weekdays} LOAD_{day}^{mtu} \quad (2.14)$$

$$LOAD_{all}^{mtu,month} = \frac{1}{dom} \sum_{day=1}^{dom} LOAD_{day}^{mtu} \quad (2.15)$$

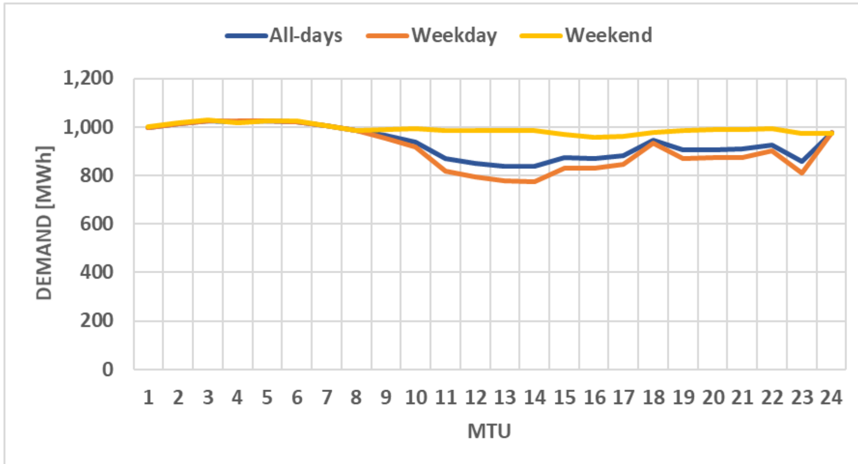
Considering the load profiles for the three months under study, the total load ranges on average from 4,164MWh to 6,782MWh for the all-day curves, from 4,185MWh to 6,903MWh for the weekday curves and from 4,116MWh to 6,491MWh for the weekend curves.

Regarding HV Load, as it is presented in Figures 2.32(a)-(c), for all three months under study, the representative curves are identical. More specifically, according to the three curves (*all-days, weekdays, weekend*), for the first 8 MTUs of the representative day, the HV load demand is the same and averagely close to 1GWh. For the MTUs 9-24 the demand differentiates according to the day of the week. The weekend curve is higher than the other two and corresponds to an averagely demand close to 1GWh. The weekday curve is lower than the other two and for the MTUs 9-24 ranges on average between 772MWh and 974MWh, considering all three months. The all-day curve for the same MTUs ranges on average between 833MWh and 974MWh.

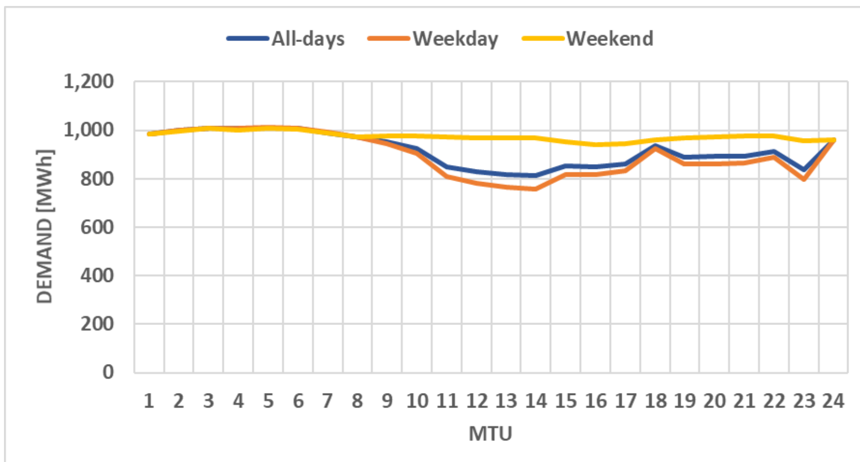
Regarding MV Load, as it is presented in Figures 2.33(a)-(c), for all three months under study, the representative curves show similar behavior, where the weekday curve is higher than the all-days curve and the weekend curve is lower than the all-days curve. For November, the all-days curve ranges from 853MWh (*mtu:4*) to 1,303MWh (*mtu:12*), the weekday curve ranges from 873MWh (*mtu:4*) to 1,434MWh (*mtu:12*) and the weekend curve ranges from 799MWh (*mtu:5*) to 1,010MWh (*mtu:18*). For December, the all-days curve ranges from 804MWh (*mtu:4*) to 1,271MWh (*mtu:12*), the weekday curve ranges from 821MWh (*mtu:4*) to 1,374MWh (*mtu:12*) and the weekend curve ranges from 746MWh (*mtu:5*) to 976MWh (*mtu:12*). For January, the all-days curve ranges from 797MWh (*mtu:4*) to 1,263MWh (*mtu:12*), the weekday curve ranges from 818MWh (*mtu:4*) to 1,386MWh (*mtu:12*) and the weekend curve ranges from 749MWh (*mtu:5*) to 1,005MWh (*mtu:12*).

Regarding LV Load, as it is presented in Figures 2.34(a)-(c), for all three months under study, the representative curves show similar behavior, where the weekday curve is slightly higher than the all-days curve and the weekend curve is lower than the all-days curve. For November, the all-days curve ranges from 2138MWh (*mtu:4*) to 4328MWh (*mtu:19*), the weekday curve ranges from 2125MWh (*mtu:4*) to 4364MWh (*mtu:19*) and the weekend curve ranges from 2170MWh (*mtu:4*) to 4243MWh (*mtu:19*). For December, the all-days curve ranges from 2344MWh (*mtu:4*) to 4770MWh (*mtu:19*), the weekday curve ranges from 2334MWh (*mtu:4*) to 4853MWh (*mtu:19*) and the weekend curve ranges from 2373MWh (*mtu:4*) to 4533MWh (*mtu:19*). For January, the all-days curve ranges from 2498MWh (*mtu:4*) to 5003MWh (*mtu:19*), the weekday curve ranges from 2518MWh (*mtu:4*) to 5104MWh (*mtu:19*) and the weekend curve ranges from 2458MWh (*mtu:4*) to 4791MWh (*mtu:19*).

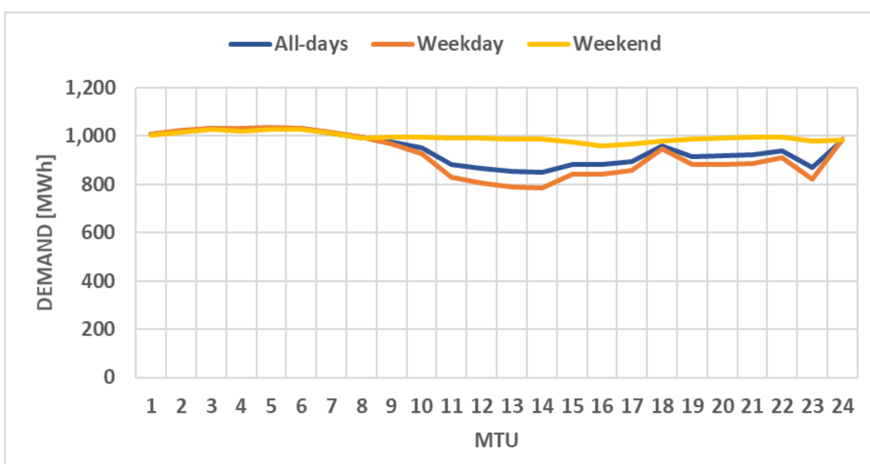
Regarding the Total Load, as it is presented in Figures 2.35(a)-(c), for all three months under study, the representative curves show similar behavior, mainly due to the fact that the highest share on the demand mix derives from LV Load, where the weekday curve is slightly higher than the all-days curve and the weekend curve is lower than the all-days curve. For November, the all-days curve ranges from 4013MWh (*mtu:4*) to 6440MWh (*mtu:19*), the weekday curve ranges from 4022MWh (*mtu:4*) to 6529MWh (*mtu:19*) and the weekend curve ranges from 3992MWh (*mtu:4*) to 6232MWh (*mtu:19*). For December, the all-days curve ranges from 4154MWh (*mtu:4*) to 6823MWh (*mtu:19*), the weekday curve ranges from 4164MWh (*mtu:4*) to 6946MWh (*mtu:19*) and the weekend curve ranges from 4125MWh (*mtu:4*) to 6470MWh (*mtu:19*). For January, the all-days curve ranges from 4324MWh (*mtu:4*) to 7084MWh (*mtu:19*), the weekday curve ranges from 4369MWh (*mtu:4*) to 7233MWh (*mtu:19*) and the weekend curve ranges from 4230MWh (*mtu:4*) to 6771MWh (*mtu:19*).



(a)

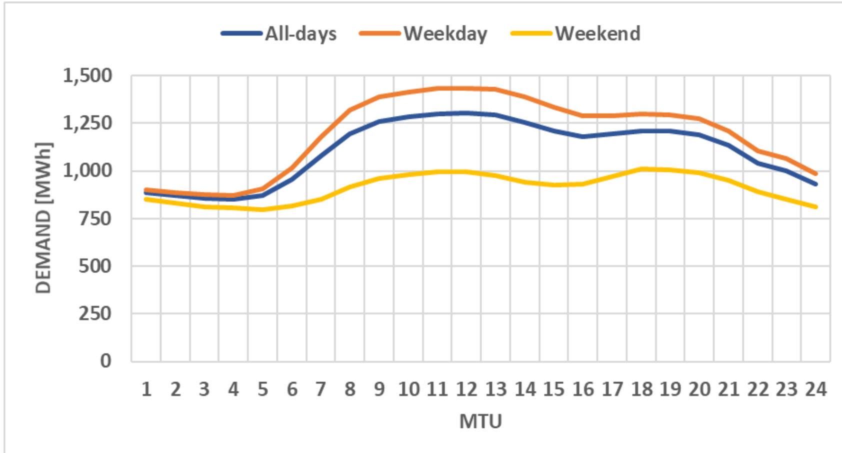


(b)

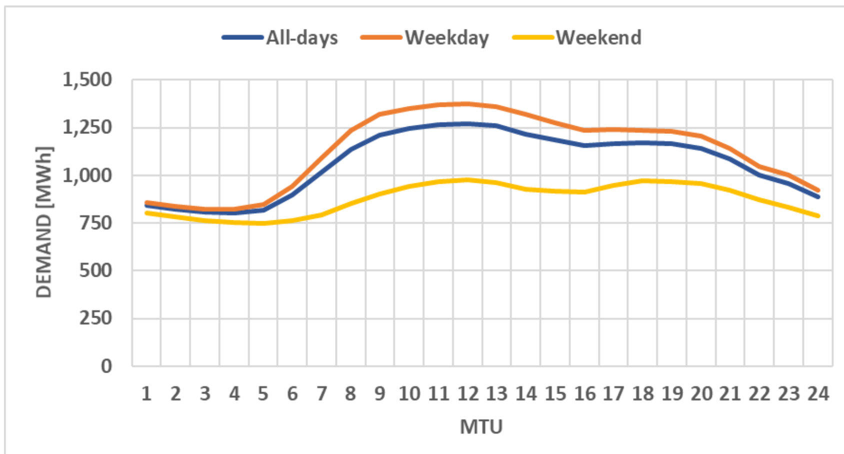


(c)

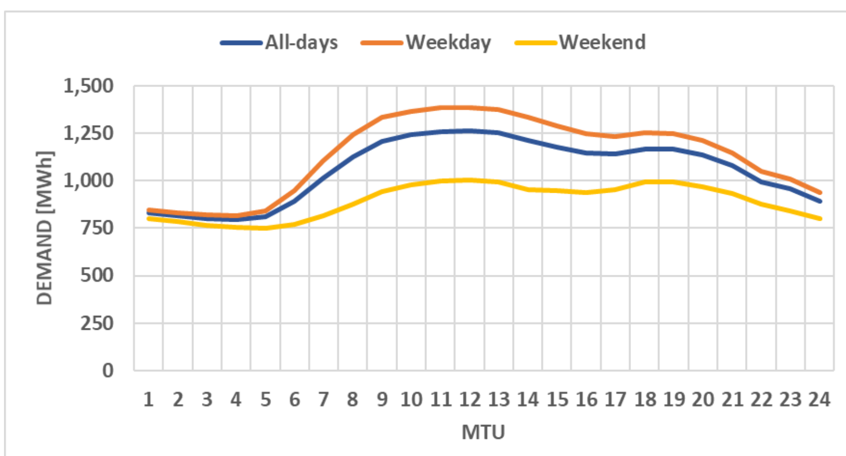
Figure 2.32. HV Load–Representative Days; (a) November 2020; (b) December 2020; (c) January 2021



(a)

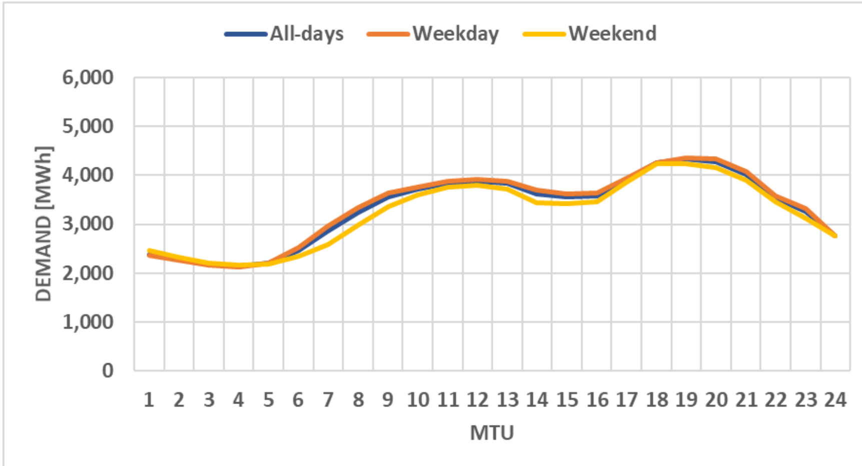


(b)

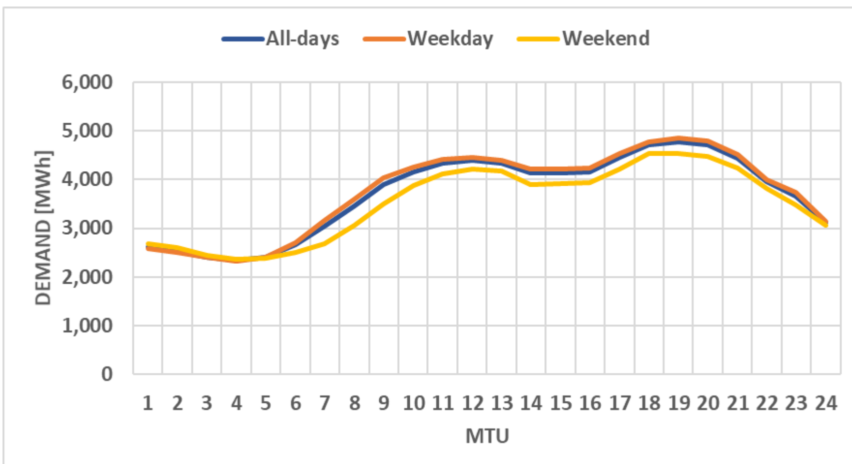


(c)

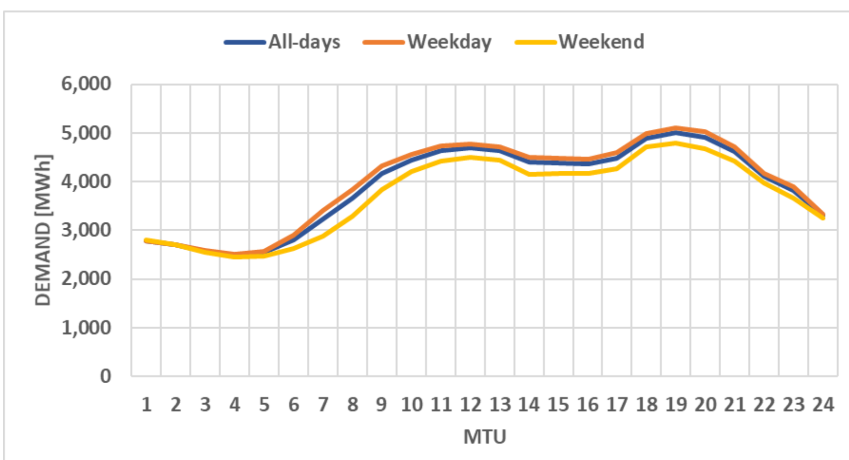
Figure 2.33. MV Load–Representative Days; (a) November 2020; (b) December 2020; (c) January 2021



(a)

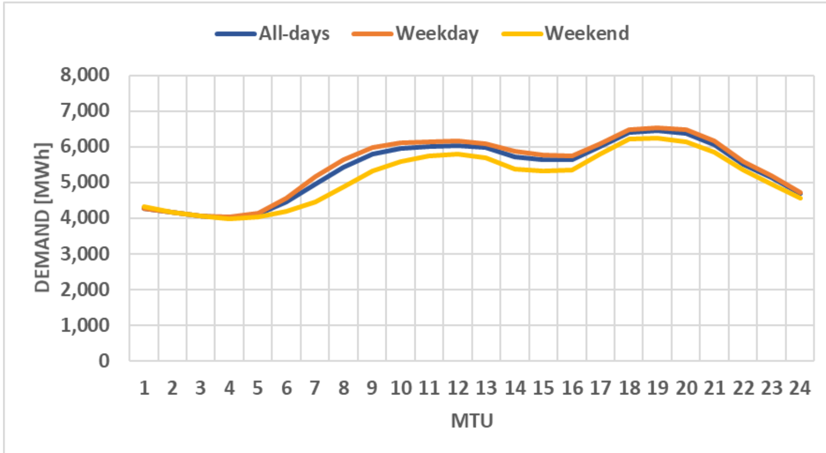


(b)

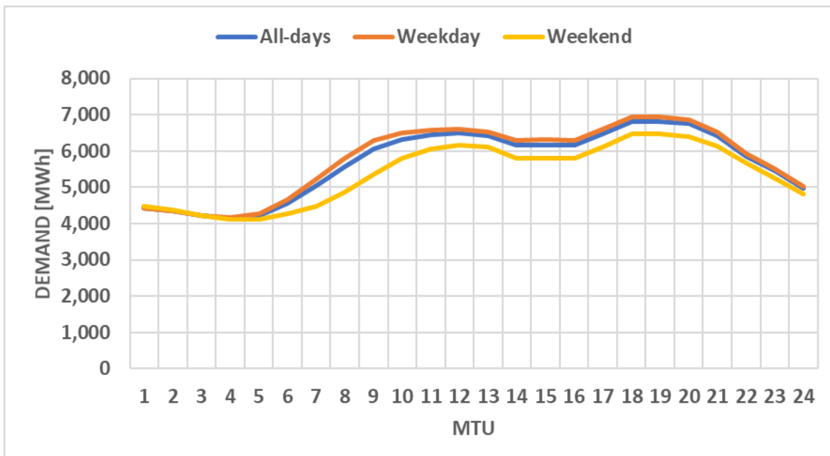


(c)

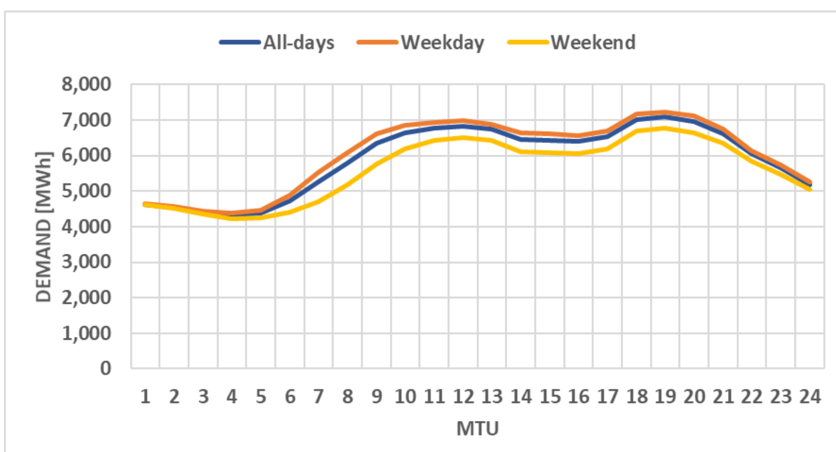
Figure 2.34. LV Load–Representative Days; (a) November 2020; (b) December 2020; (c) January 2021



(a)



(b)



(c)

Figure 2.35. Total Load–Representative Days; (a) November 2020; (b) December 2020; (c) January 2021

2.3.3 Cross-Border Trading (CBT)

Regarding the Cross-Border Trading of electricity, Greece borders with Albania, North Macedonia, Bulgaria, Turkey and Italy. It is noted that form 15.12.2020 the Day-Ahead Markets of Italy and Greece are coupled, which means the implicit allocation of Physical Transmission Rights (PTRs) in the prices of the offered quantities. The Net Transfer Capacity (NTC) for each interconnection differs by the border and the Available Transfer Capacity (ATC) on a respective border may differ by direction (imports/exports) and by date. The interconnection's NTC for the Albanian border is equal to 400MW (both imports & exports), for the North Macedonian border is equal to 400MW for imports & 550MW for exports, for Bulgarian border is equal to 750MW (both imports & exports), for the Turkish border is equal to 50MW for imports and 216MW for exports and for the Italian border is equal to 500MW (both imports & exports) [62].

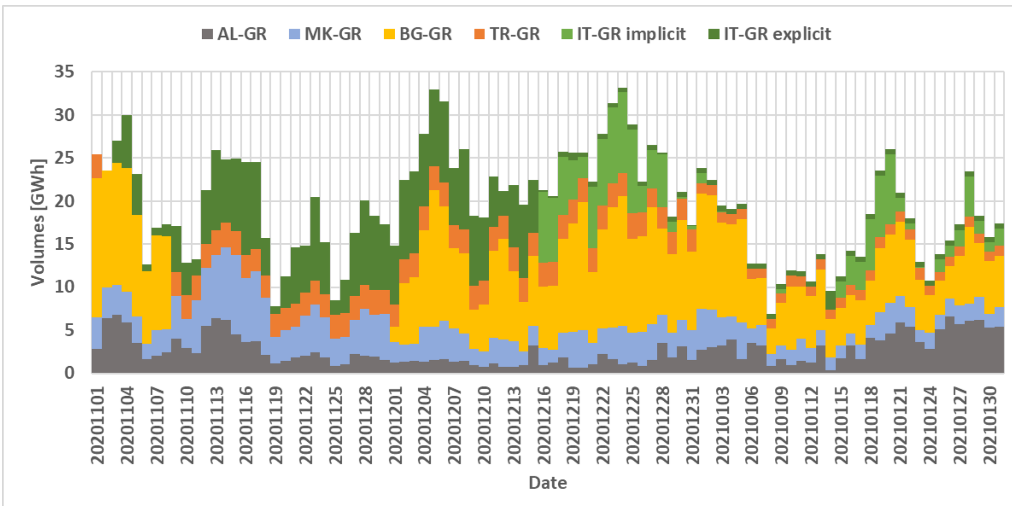


Figure 2.36. Schedules of Imports per Border from 01.11.2020 to 31.01.2021

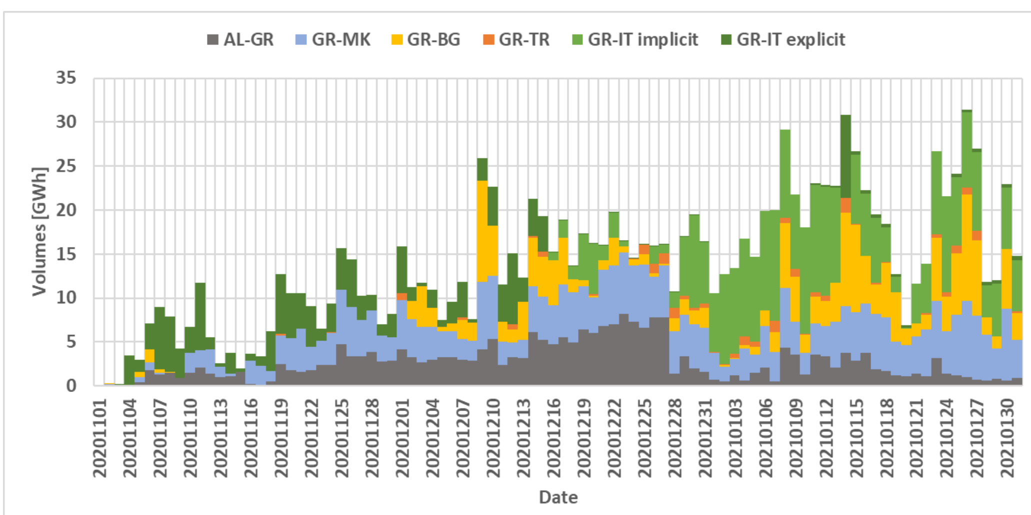


Figure 2.37. Schedules of Exports per Border from 01.11.2020 to 31.01.2021

The Figure 2.36 illustrates the imported volumes of energy per border from 01.11.2020 to 31.01.2021 in a daily resolution. The Figure 2.37 illustrates the exported volumes of energy per border for the same period in a daily resolution. The volumes of imported energy are higher than the ones of exported energy. Focusing on imports, the majority of the quantities are imported from the Bulgarian border. Regarding the exports, the majority of exported volumes correspond to Albania, North Macedonia and Italy.

In Figure 2.38 the totals of imported and exported scheduled quantities [58] are presented, as well as the aggregated net direction of the scheduled trading for the period 01.11.2020-31.01.2021, on a daily resolution. The exports are represented in the negative vertical axis for better presentation of the results. As shown in the respective Figure, the most of the days the scheduling of traded cross-border electricity corresponds to net imports for the Greek power system. In December, for the majority of the days, Greece was a net exporter, whereas in November and December Greece resulted as a net importer for the majority of the days. More specifically, the Greek power system was a net importer for the 73% of the days under study and at a percentage of 27% of the respective days Greece was a net exporter.

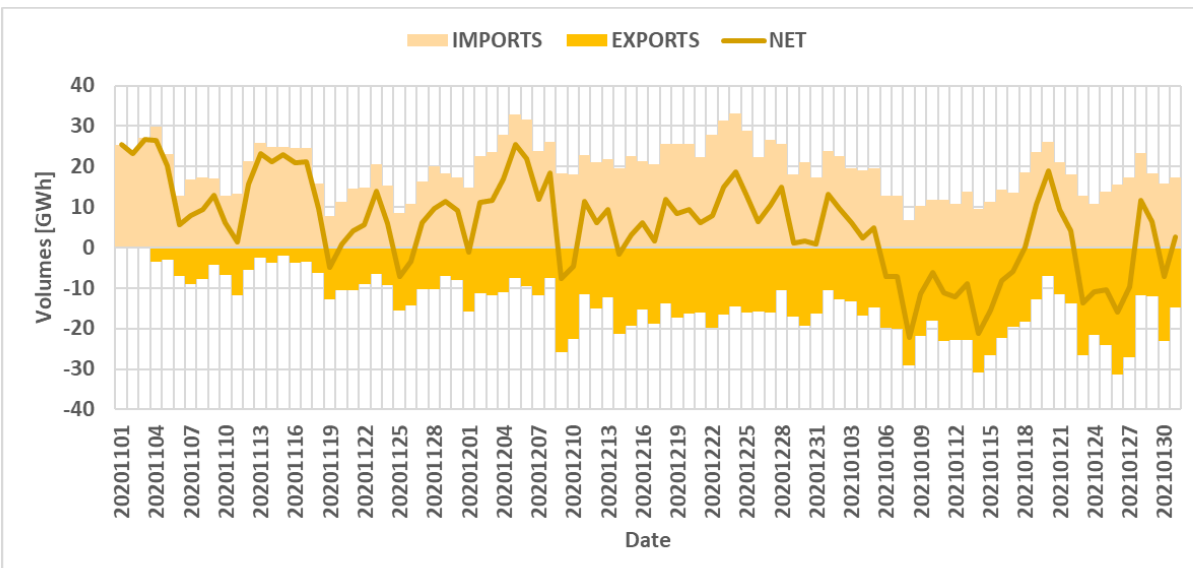


Figure 2.38. Total Cross-border Schedules from 01.11.2020 to 31.01.2021

In Figures 2.39-2.43 the imports, exports and net position per border are presented in a daily resolution. More specifically, regarding the Albanian border, as shown in Figure 2.39, the scheduled quantities of imports (AL-GR) were higher than of exports (GR-AL) for most of the days of November and January, resulting a position of net importer against the Albanian border for the respective periods. For the last days of November as well as almost the total of days in December the scheduled traded quantities correspond to the position of net exporter for Greece. More specifically, at a percentage of 47% of the days under study the Greek power system was a net importer, and at a percentage of 53% was a net exporter. Also, for the period under study, the daily quantities for imports range between 0.40GWh and 6.78GWh and for exports between 0.00GWh and 8.15GWh.

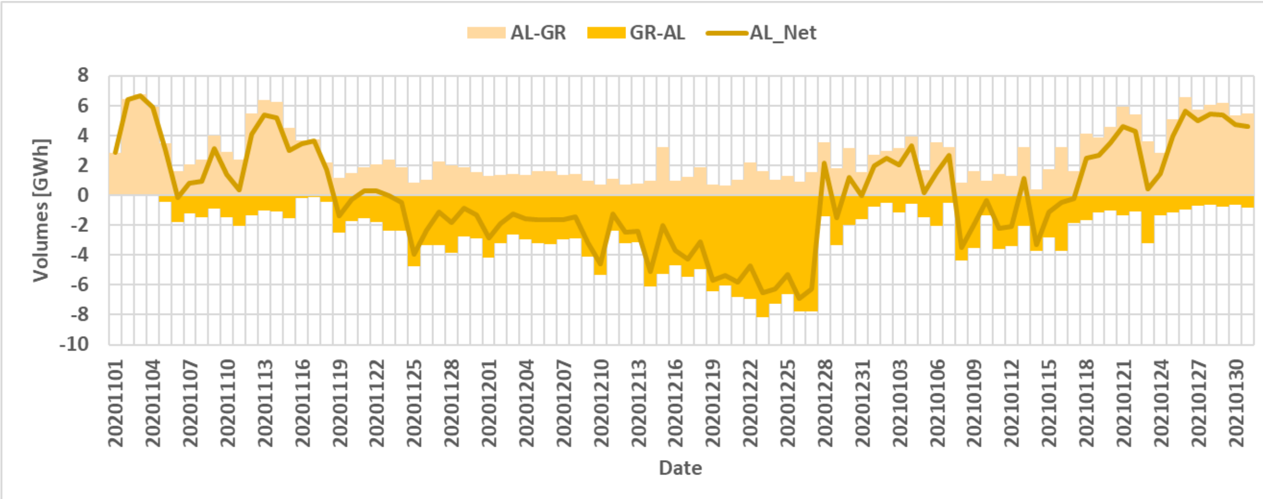


Figure 2.39. Albania (AL) Cross-border Schedules from 01.11.2020 to 31.01.2021

Regarding the border between Greece and North Macedonia, as shown in Figure 2.40, the scheduled quantities of imports (MK-GR) were lower than of exports (GR-MK) for most of the days under study and more specifically for most of the days in December and January, resulting Greece as a net exporter to North Macedonia for the respective months in the majority of the days. Furthermore, during November the imports were higher than exports resulting a net importing position for Greece in the respective border. More specifically, for a percentage of 41% of the days under study the Greek power system was a net importer and for a percentage of 59% was a net exporter. Also, for the period under study, the daily quantities for imports range between 1.32GWh and 9.24GWh and for exports between 0.00GWh and 8.72GWh.

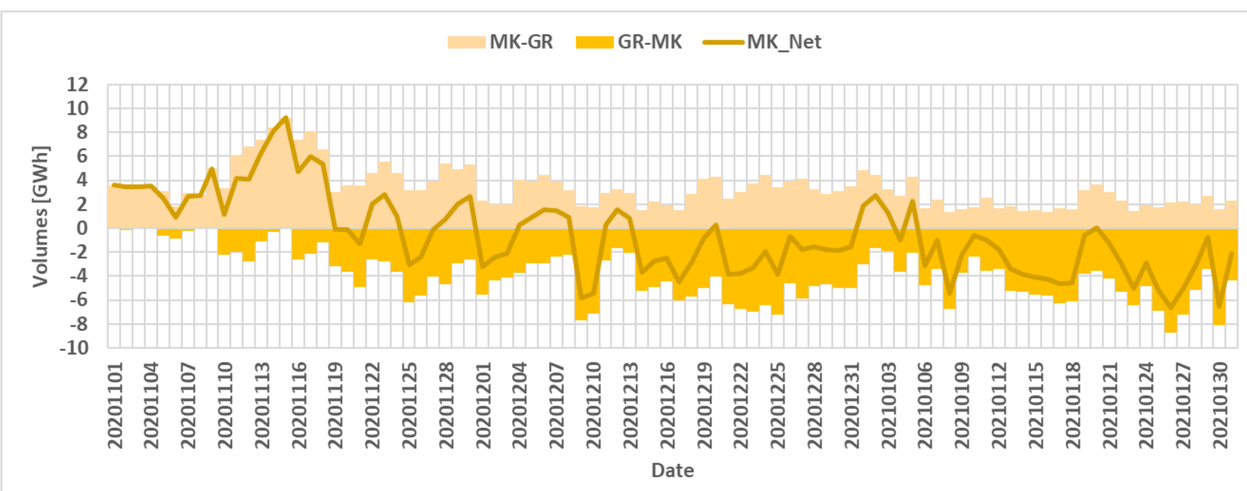


Figure 2.40. North Macedonia (MK) Cross-border Schedules from 01.11.2020 to 31.01.2021

Regarding the Bulgarian border, as shown in Figure 2.41, the scheduled quantities of imports (BG-GR) were higher than of exports (GR-BG) for most of the days under study and more specifically for all the days in November, the majority of the days in December and January, resulting Greece as a net importer to the Bulgarian border for the respective periods. Furthermore, during November (09.11.2020-30.11.2020) the interconnection was out of service so there was no trading activity for the respective time period. More specifically, for a percentage of 81% of the days under study, the Greek power system was a net importer and for a percentage at 19% was a net exporter. Also, for the period under study, excluding the time of out-of-service period of the interconnection, the daily quantities for imports range between 1.76GWh and 16.19GWh and for exports between 0.00GWh and 12.15GWh.

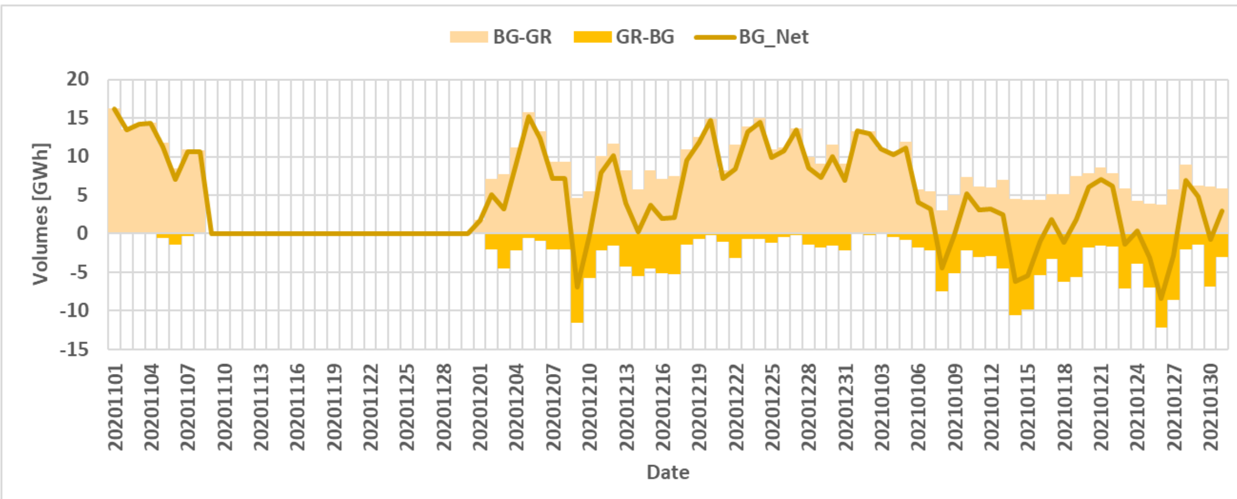


Figure 2.41. Bulgaria (BG) Cross-border Schedules from 01.11.2020 to 31.01.2021

Regarding the Turkish border, as shown in Figure 2.42, the scheduled quantities of imports (TR-GR) were higher than of exports (GR-TR) almost for the whole period of days under study, with the only exception being on 14.01.2021, resulting Greece as a net importer to the Turkish border. Furthermore, during November (02.11.2020-08.11.2020) the interconnection was out of service so there was no trading activity for the respective time period. More specifically, for a percentage of 98% of the days under study the Greek power system was a net importer and for a percentage at 2% was a net exporter. Also, for the period under study, excluding the time out-of-service period of the interconnection, the daily quantities for imports range between 1.02GWh and 2.96GWh and for exports between 0.00GWh and 1.76GWh.

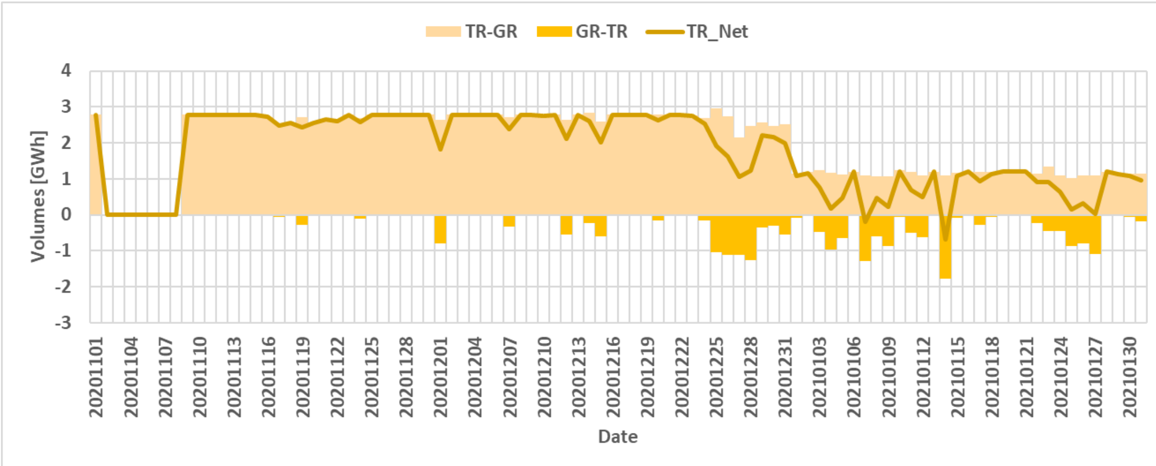


Figure 2.42. Turkey (TR) Cross-border Schedules from 01.11.2020 to 31.01.2021

Regarding the Italian border, as shown in Figure 2.43, the scheduled quantities of imports (IT-GR) were higher than of exports (GR-IT) for most of the days of November and December, resulting a position of net importer against the Italian border for the respective periods. Almost the total of days in January the scheduled traded quantities correspond to the position of net exporter for Greece with an exception between 18.01.2021-22.01.2021, where the net position resulted as net importer for Greece in the respective border. More specifically, for a percentage of 53% of the days under study the Greek power system was a net importer and for a percentage of 47% was a net exporter. Also, for the period under study the daily quantities for imports range between 0.57GWh and 10.81GWh and for exports between 0.00GWh and 12.60GWh.

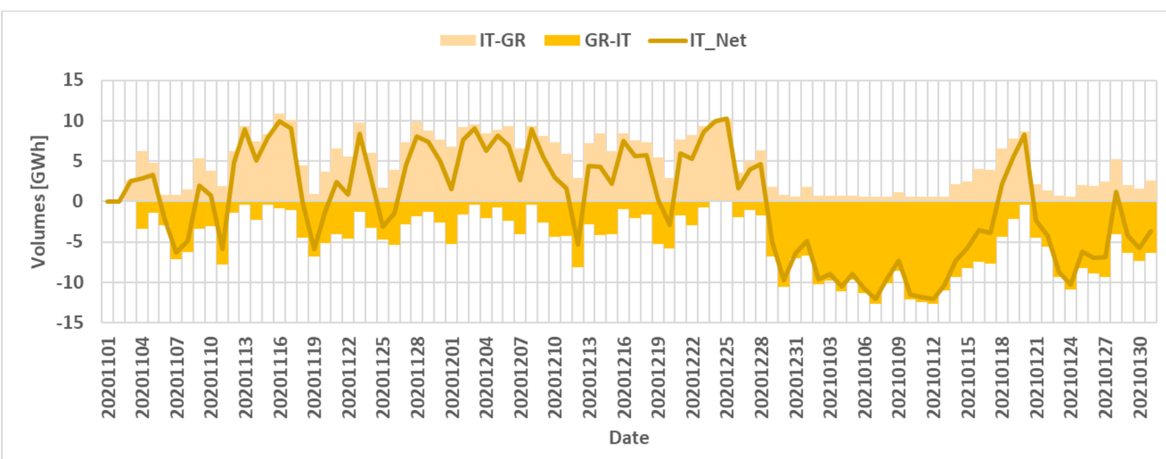


Figure 2.43. Italy (IT) Cross-border Schedules from 01.11.2020 to 31.01.2021

The activity of cross-border trading between Greece and Italy is further presented in Figures 2.44 and 2.45, as from the 15.12.2020 the Greek and Italian Day-Ahead Power Markets are coupled. As it can be seen from the respective Figures, after the coupling between the two markets the trading is performed implicitly for the vast majority of the respective quantities.

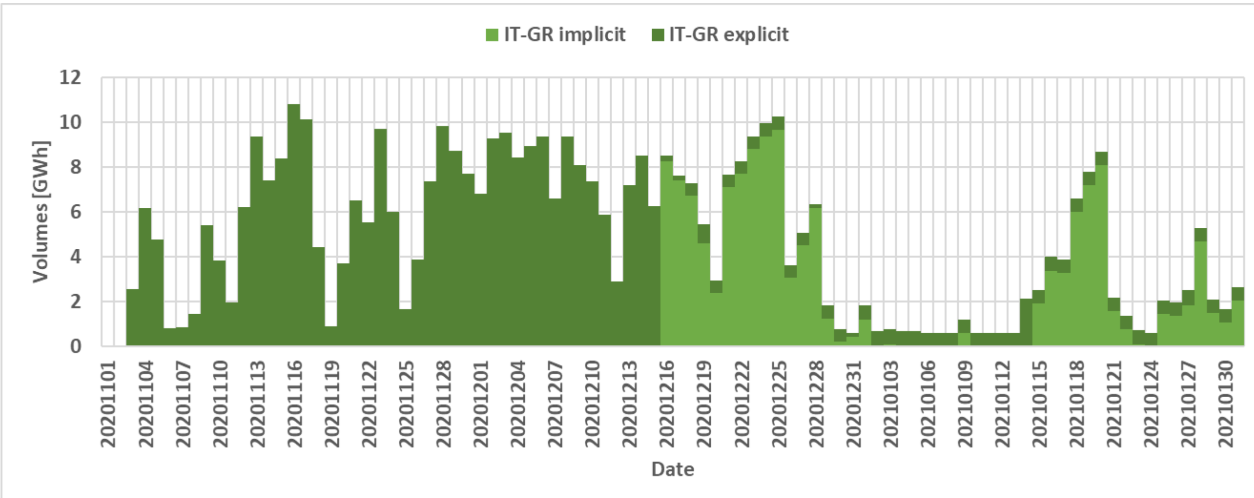


Figure 2.44. Italy (IT) - Imports (implicit & explicit) from 01.11.2020 to 31.01.2021

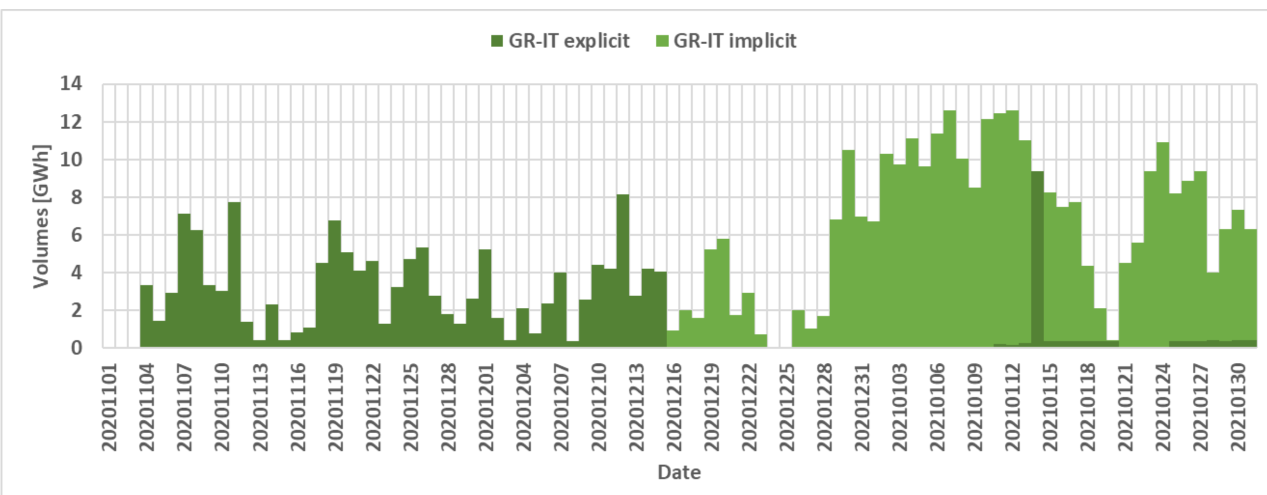


Figure 2.45. Italy (IT) - Exports (implicit & explicit) from 01.11.2020 to 31.01.2021

2.3.3.1 Borders Prices differentials (margins)

The economic power flow direction is defined as the one from the country with the lower price to the country with higher price. In order to analyze the cross-border trading activity in Greece[1] between Bulgaria, Turkey and Italy the respective margins are calculated according to the equation (2.16), in a daily resolution, which means that the average daily prices [63] for each bidding zone are considered in order to characterize the direction of power flows (imports/exports) as economic or non-economic.

$$Margin_{Border}^{day} = GR\_MCP_{average}^{day} - Border\_MCP_{average}^{day} \tag{2.16}$$

The systematic appearance of price differentials between two power systems (*bidding zones*), corresponds to the congestion of the respective interconnection. So, price differentials constitute a signal for investment in the increase of cross-zonal capacity.

In Figure 2.46 there are presented the scheduled quantities for import and exports, the resulted net position and the respective price differentials (margins) between the two power systems of Bulgaria and Greece, on a daily resolution for the time period 01.11.2020 - 31.01.2021. The margins on a daily basis span from -21.14€/MWh and 33.82€/MWh. The power flow is characterized as economic for the 60% of the scheduled quantities on a daily resolution and at a percentage of 40% the cross-border trading schedule between Bulgaria and Greece is characterized as non-economic (*wrong direction power flows*).

In Figure 2.47 there are presented the scheduled quantities for import and exports, the resulted net position and the respective price differentials (margins) between the two power systems of Turkey and Greece, on a daily resolution for the time period 01.11.2020 - 31.01.2021. The margins on a daily basis span from 3.48€/MWh to 57.58€/MWh. The power flow is characterized as economic for the 90% of the scheduled quantities on a daily resolution and at a percentage of 10% the cross-border trading schedule between Turkey and Greece is characterized as non-economic (*wrong direction power flows*).

In Figure 2.48 there are presented the scheduled quantities for import and exports, the resulted net position and the respective price differentials (margins) between the two power systems of Italy and Greece, on a daily resolution for the time period 01.11.2020 - 31.01.2021. The margins on a daily basis span from -26.32€/MWh to 25.88€/MWh. The power flow is characterized as economic for the 83% of the scheduled quantities on a daily resolution and at a percentage of 17% the cross-border trading schedule between Italy and Greece is characterized as non-economic (*wrong direction power flows*).

[1] Due to the unavailability of the wholesale price data of Albania and North Macedonia, the analysis of the present section is performed on the Bulgarian, Turkish and Italian borders, based on data from energylive.com [63]

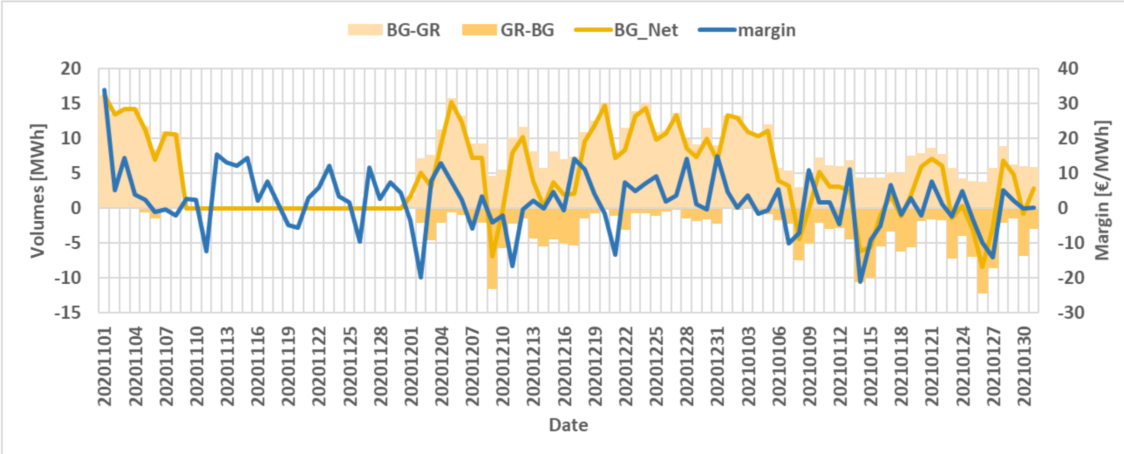


Figure 2.46. Bulgaria (BG) Cross-border Scheduling & daily Margins from 01.11.2020 to 31.01.2021

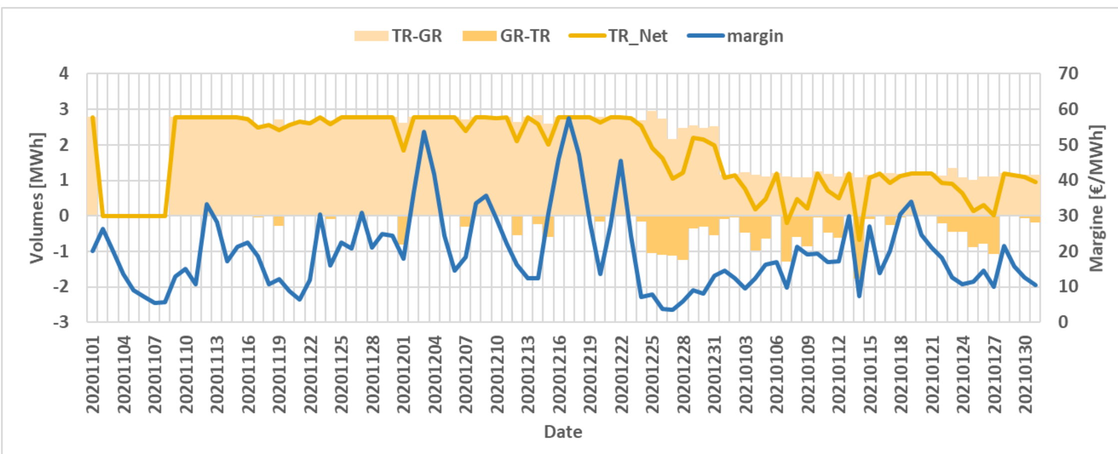


Figure 2.47. Turkey (TR) Cross-border Scheduling & daily Margins from 01.11.2020 to 31.01.2021

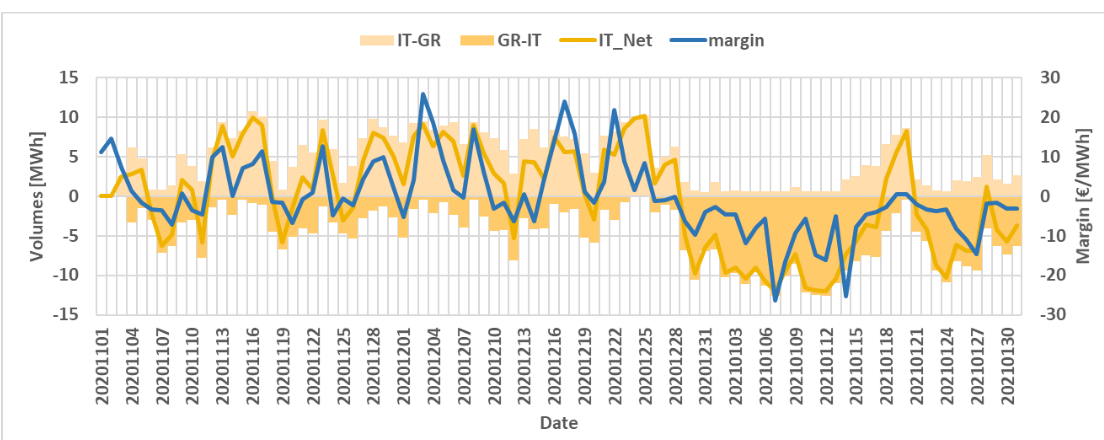


Figure 2.48. Italy (IT) Cross-border Scheduling & daily Margins from 01.11.2020 to 31.01.2021

In tables 2.23-2.25 the results of average daily prices for Greece, Bulgaria, Italy and Turkey are presented, as well as the corresponding margins and the economic direction of the power flow on a daily basis. The Table 2.23 refers to November, the Table 2.24 refers to December and the Table 2.25 refers to January.

Table 2.23. Daily Margins per Border & Directions of economic power flow – November 2020

	Daily Average Prices				Margins			Economic Power Flow Direction		
DATE	Greece	Bulgaria	Italy	Turkey	Bulgaria	Italy	Turkey	Bulgaria	Italy	Turkey
20201101	53.56	19.74	42.26	33.43	33.82	11.30	20.13	imports	imports	imports
20201102	60.99	55.82	46.41	34.65	5.17	14.57	26.34	imports	imports	imports
20201103	56.01	41.69	48.55	35.94	14.33	7.46	20.08	imports	imports	imports
20201104	47.48	43.57	46.13	33.93	3.91	1.35	13.55	imports	imports	imports
20201105	43.25	40.89	44.81	34.09	2.36	-1.56	9.16	imports	exports	imports
20201106	40.38	41.36	43.66	33.18	-0.98	-3.28	7.20	exports	exports	imports
20201107	37.78	38.15	41.38	32.41	-0.37	-3.60	5.37	exports	exports	imports
20201108	36.29	38.22	43.53	30.50	-1.93	-7.25	5.78	exports	exports	imports
20201109	47.43	44.77	46.66	34.58	2.67	0.77	12.85	imports	imports	imports
20201110	48.49	46.14	52.02	33.53	2.35	-3.53	14.96	imports	exports	imports
20201111	44.80	57.04	49.38	33.96	-12.24	-4.58	10.84	exports	exports	imports
20201112	68.09	52.54	58.14	34.83	15.55	9.95	33.26	imports	imports	imports
20201113	64.75	51.62	52.36	36.49	13.13	12.39	28.26	imports	imports	imports
20201114	51.20	38.97	51.07	33.99	12.23	0.13	17.21	imports	imports	imports
20201115	54.31	39.78	47.23	32.97	14.54	7.08	21.34	imports	imports	imports
20201116	60.44	58.24	52.17	37.99	2.20	8.27	22.45	imports	imports	imports
20201117	58.87	51.27	47.38	40.18	7.60	11.49	18.69	imports	imports	imports
20201118	47.59	46.02	48.90	36.95	1.56	-1.31	10.64	imports	exports	imports
20201119	46.26	50.98	47.87	34.18	-4.72	-1.61	12.08	exports	exports	imports
20201120	43.64	49.11	50.27	34.75	-5.47	-6.63	8.89	exports	exports	imports
20201121	41.11	38.20	41.79	34.75	2.92	-0.68	6.36	imports	exports	imports
20201122	42.98	36.90	41.97	30.93	6.08	1.01	12.05	imports	imports	imports
20201123	68.36	56.16	55.67	38.07	12.20	12.69	30.29	imports	imports	imports
20201124	52.87	49.41	57.62	36.77	3.46	-4.75	16.10	imports	exports	imports
20201125	56.45	54.81	57.00	33.92	1.64	-0.55	22.53	imports	exports	imports
20201126	56.12	65.59	58.46	35.29	-9.47	-2.35	20.83	exports	exports	imports
20201127	72.01	60.27	67.59	41.11	11.74	4.42	30.90	imports	imports	imports
20201128	60.18	57.57	51.35	39.21	2.60	8.82	20.96	imports	imports	imports
20201129	58.14	50.60	48.30	33.17	7.54	9.84	24.96	imports	imports	imports
20201130	59.84	55.40	57.62	35.54	4.44	2.22	24.30	imports	imports	imports

Table 2.24. Daily Margins per Border & Directions of economic power flow – December 2020

	Daily Average Prices				Margins			Economic Power Flow Direction		
DATE	**Greece**	**Bulgaria**	**Italy**	**Turkey**	**Bulgaria**	**Italy**	**Turkey**	**Bulgaria**	**Italy**	**Turkey**
20201201	52.89	56.52	58.09	35.05	-3.62	-5.20	17.84	exports	exports	imports
20201202	74.00	93.86	69.79	37.39	-19.86	4.22	36.62	exports	imports	imports
20201203	90.69	82.82	64.81	37.11	7.87	25.88	53.57	imports	imports	imports
20201204	77.27	64.42	58.50	35.61	12.85	18.77	41.66	imports	imports	imports
20201205	60.46	52.73	51.31	36.08	7.73	9.15	24.37	imports	imports	imports
20201206	48.09	45.59	46.57	33.39	2.49	1.51	14.70	imports	imports	imports
20201207	53.69	59.41	53.91	35.22	-5.72	-0.22	18.48	exports	exports	imports
20201208	71.17	67.62	54.21	37.58	3.55	16.96	33.59	imports	imports	imports
20201209	71.94	76.00	65.59	36.14	-4.07	6.35	35.80	exports	imports	imports
20201210	63.09	65.07	66.10	33.81	-1.98	-3.01	29.28	exports	exports	imports
20201211	56.90	73.39	58.41	34.56	-16.49	-1.50	22.34	exports	exports	imports
20201212	48.63	48.85	54.95	32.38	-0.22	-6.32	16.25	exports	exports	imports
20201213	44.01	41.69	43.44	31.65	2.33	0.57	12.36	imports	imports	imports
20201214	46.13	46.20	52.45	33.61	-0.07	-6.32	12.52	exports	exports	imports
20201215	64.90	60.09	60.23	34.24	4.81	4.68	30.67	imports	imports	imports
20201216	80.36	80.80	66.17	34.40	-0.44	14.19	45.96	exports	imports	imports
20201217	93.78	79.61	69.86	36.21	14.18	23.92	57.58	imports	imports	imports
20201218	82.31	71.17	66.40	35.01	11.15	15.92	47.30	imports	imports	imports
20201219	62.33	58.12	61.12	34.33	4.21	1.21	28.00	imports	imports	imports
20201220	47.12	48.62	48.80	33.39	-1.50	-1.68	13.73	exports	exports	imports
20201221	62.88	76.12	59.09	35.60	-13.24	3.79	27.29	exports	imports	imports
20201222	82.02	74.60	60.06	36.55	7.42	21.96	45.47	imports	imports	imports
20201223	62.60	57.58	53.75	38.17	5.01	8.85	24.43	imports	imports	imports
20201224	43.40	36.24	41.90	36.33	7.16	1.50	7.07	imports	imports	imports
20201225	41.83	32.67	33.34	34.06	9.16	8.49	7.77	imports	imports	imports
20201226	37.74	35.76	38.91	33.97	1.97	-1.18	3.77	imports	exports	imports
20201227	35.75	32.10	36.62	32.27	3.65	-0.87	3.48	imports	exports	imports
20201228	40.38	26.14	40.44	34.45	14.24	-0.06	5.93	imports	exports	imports
20201229	43.37	42.08	49.72	34.38	1.29	-6.35	8.99	imports	exports	imports
20201230	42.05	42.36	51.68	33.99	-0.32	-9.63	8.06	exports	exports	imports
20201231	45.19	30.31	49.23	32.02	14.88	-4.04	13.17	imports	exports	imports

Table 2.25. Daily Margins per Border & Directions of economic power flow – January 2021

	Daily Average Prices				Margins			Economic Power Flow Direction		
DATE	Greece	Bulgaria	Italy	Turkey	Bulgaria	Italy	Turkey	Bulgaria	Italy	Turkey
20210101	45.58	40.85	48.17	30.91	4.73	-2.59	14.67	imports	exports	imports
20210102	47.11	47.00	51.64	34.78	0.11	-4.53	12.33	imports	exports	imports
20210103	43.47	39.74	48.01	34.03	3.73	-4.54	9.44	imports	exports	imports
20210104	47.46	49.05	59.33	34.92	-1.59	-11.87	12.54	exports	exports	imports
20210105	50.89	51.55	58.80	34.54	-0.65	-7.90	16.35	exports	exports	imports
20210106	52.84	47.33	58.43	35.85	5.51	-5.59	16.99	imports	exports	imports
20210107	44.64	54.67	70.97	34.77	-10.03	-26.32	9.88	exports	exports	imports
20210108	55.72	62.87	72.28	34.43	-7.15	-16.56	21.29	exports	exports	imports
20210109	51.64	40.64	61.00	32.42	11.00	-9.36	19.22	imports	exports	imports
20210110	51.96	50.24	57.71	32.51	1.72	-5.75	19.45	imports	exports	imports
20210111	51.65	50.03	66.49	34.65	1.62	-14.84	17.00	imports	exports	imports
20210112	52.47	57.07	68.56	35.30	-4.61	-16.09	17.17	exports	exports	imports
20210113	67.76	56.58	72.70	37.92	11.18	-4.93	29.84	imports	exports	imports
20210114	46.16	67.30	71.42	38.79	-21.14	-25.27	7.37	exports	exports	imports
20210115	63.69	72.63	71.46	36.73	-8.94	-7.77	26.96	exports	exports	imports
20210116	50.96	56.11	55.44	36.97	-5.15	-4.49	13.99	exports	exports	imports
20210117	53.98	47.37	57.93	33.97	6.61	-3.95	20.01	imports	exports	imports
20210118	66.95	68.72	69.67	36.63	-1.77	-2.72	30.32	exports	exports	imports
20210119	71.73	68.65	71.26	37.72	3.08	0.47	34.01	imports	imports	imports
20210120	63.45	65.58	62.90	38.80	-2.13	0.55	24.64	exports	imports	imports
20210121	59.68	51.94	61.66	38.66	7.74	-1.97	21.03	imports	exports	imports
20210122	56.05	54.91	59.30	37.87	1.14	-3.25	18.18	imports	exports	imports
20210123	47.24	49.44	50.91	34.58	-2.20	-3.67	12.66	exports	exports	imports
20210124	43.28	38.33	46.58	32.42	4.95	-3.30	10.86	imports	exports	imports
20210125	45.70	48.82	53.93	34.20	-3.12	-8.23	11.50	exports	exports	imports
20210126	49.53	59.23	60.59	34.88	-9.70	-11.05	14.66	exports	exports	imports
20210127	45.39	59.31	60.10	35.34	-13.92	-14.71	10.05	exports	exports	imports
20210128	59.98	54.89	61.86	38.46	5.09	-1.89	21.52	imports	exports	imports
20210129	52.13	50.02	53.64	36.43	2.11	-1.50	15.71	imports	exports	imports
20210130	46.75	46.76	49.80	34.15	-0.01	-3.05	12.60	exports	exports	imports
20210131	42.28	42.04	45.40	31.65	0.23	-3.13	10.62	imports	exports	imports

3 Balancing Market

The Balancing Market is implemented through the Balancing Capacity Market, the Balancing Energy Market and the Imbalance Settlement Procedure. As the Balancing Market in Greece follows the Central Dispatch model, the TSO performs the executions of the Integrated Scheduling Procedure (ISP) that provides the binding schedules for the BSPs that participate in the Balancing Market, as well as the awarded capacity of ancillary services (FCR, aFRR, mFRR) in a unit-based manner. For each delivery day D, the ISP is executed three times (ISP1, ISP2, ISP3) but also it can be executed any additional time (Ad-hoc ISP) that the TSO deems it is necessary. In Table 3.1 there are presented in a concise way the timeframes of the binding results for each ISP, as well as, the times of the corresponding executions [64].

Table 3.1. ISP timings of executions and results

ISP	Day and Time	ISP periods Results	Binding Results
ISP1	CET 16:45 D-1	48 ISP periods (00:00-24:00)	None
ISP2	CET 23:00 D-1	48 ISP periods (00:00-24:00)	First 24 ISP periods (00:00-12:00)
ISP3	CET 11:00 D	24 ISP periods (12:00-24:00)	Last 24 ISP periods (12:00-24:00)
Ad-hoc ISP	Any time before the end of day D	Depending on the time of execution of the Ad-hoc ISP	All ISP periods that are included in results

Due to the fact that the ISP executions correspond to the co-optimization of Balancing Capacity and Balancing Energy for the respective ISP periods (30-min) with the time of execution being quite earlier (*from 1 to 12 hours ahead*) than the delivery time, the results regarding Balancing Energy are indicative. Additionally, in the scope of the RTBM, the optimization considers only the Balancing Energy with a timeframe of 15-min and the execution takes place 15-min before delivery time.

Regarding the participation in the BM, only the Thermal and Hydro producers are provisioned to offer Balancing Services, whereas it is anticipated for RES aggregators to be allowed to participate in the BM also, and subsequently take full responsibility of their assets' imbalances. The Market Participants that are obliged to place their offers in the Balancing Market are the BSPs. The BSPs are obliged to place their offers in the scope of the ISP executions regarding Balancing Capacity Products, as well as Balancing Energy Products, which the latter, in the scope of ISP results, produce just indicative schedules for activated Balancing Energy. However, the dispatch schedule (start-up/shut-down of a generation unit) that is formulated based on the ISP offers, is binding also for the RTBM. The offers are places for upwards and downwards capacity and energy services for each Balancing Service Providing entity (BSPe) represented by the BSPs, for every ISP period. Finally, for every BSPe, for each ISP period the BSPs can form a bidding curve with up to ten steps, in order to be able to enhance the effectiveness of their bidding strategy and ultimately increase their inflows from the market. Especially regarding the Balancing Energy offers, the BSPs have the chance to place updated offers in the scope of RTBM in a 15-min resolution, that replace the aforementioned ISP offers, in case that the BSPs do not submit updated offers the ISP offers are taken into consideration by the RTBM algorithm. The updates regarding the RTBM offers refer to the prices not to the volumes that correspond to the bidding curve, and more specifically, for upwards energy mean lower offered price and for downwards energy mean higher offered price.

The Balancing Capacity products of which the BSPs are obliged to place their offers are three, as listed below, for both upwards and downwards direction and their remuneration follows the pay-as-bid logic:

- Frequency Containment Reserves (FCR)
- automatic Frequency Restoration Reserves (aFRR)
- manual Frequency Restoration Reserves (mFRR)

The Balancing energy products of which the BSPs are obliged to place their offers for their eligible assets are two, as listed below, for both upwards and downwards direction:

- Activated Balancing Energy through automatic Frequency Restoration Reserves (aFRR-Act.En.)
- Activated Balancing Energy through manual Frequency Restoration Reserves (mFRR-Act.En.)

The activated Balancing Energy of aFRR is implemented through the Automatic Generation Control (AGC) and is remunerated with the pay-as-bid logic, whereas the remuneration of the activated Balancing Energy of mFRR follows the pay-as-cleared logic, meaning that the remuneration is performed according to the marginal pricing of the market on the corresponding settlement period (15-min).

The Imbalance Settlement Procedure in performed based on a period with a time resolution of 15-min (settlement period), and considers per settlement period and per asset, the Market Schedule, the ISP results (regarding Capacity & binding schedule), the RTBM results and the SCADA metering, in order to provide the economic positions of the BSPs and BRPs that participated in the Balancing Market. More specifically, regarding Balancing Capacity remuneration, during the RTBM the TSO establishes the actual availability of the awarded capacities in the ISP, in a 15-min time resolution through SCADA metering and defines the actual capacity eligible for remuneration according to the metered availability. Accordingly, for the remuneration of the activated Balancing Energy, the TSO calculates the differences between the Market Schedule of the last HEnEx Market position (DAM and/or LIDA) and the Dispatching Instruction during the RTBM and according to the availability, as described above, calculates the volumes eligible for remuneration. Lastly, the Imbalances are calculated according to the differences between the Dispatching Instructions and the actual production according to SCADA metering.

The Imbalance Settlement Procedure is executed on a weekly basis and the first results are available on W+1. On W+7 it is performed a recalculation of the Imbalance Settlement Procedure which considers updated data. The final settlement of year Y is divided into two "Clearing Semesters". The final settlement of the first semester of year Y is resulted on W+40 of year Y and the final settlement of the second semester of year Y is resulted on W+14 of year Y+1. In the scope of the recalculated and final settlements results, there are considered updated data regarding SCADA metering, updates on the submitted data from HEnEx and/or HEDNO, reevaluated data of the RTBM and consideration of possible disputes between MPs and the TSO regarding the results of the previous settlements.

The current chapter is organized as follows: In the first section the balancing market cost is presented according to the TSO's official weekly report and the corresponding public analytical data. In the same section, follows a more detailed analysis on volumes and prices that formulated the final cost of the Balancing Market. In the second section, the ISP results are analyzed and presented, as well as the offers (*public data*) that are submitted from the Market Participants in the scope of the ISPs executions. Finally, in the third section, there are investigated the correlations in volumes and prices between the ISP results and the Imbalance Settlement Procedure results.

3.1 Imbalance Settlement Procedure Results

In the scope of the Imbalance Settlement Procedure there are defined the costs of the MPs for their participation in the market, which include apart from the Imbalance costs, the costs of the Uplift Accounts (UA) 1,2 and 3. The UA1 corresponds to the system losses, the UA2 corresponds to the Balancing Capacity costs and the UA3 corresponds to the TSO's economic neutrality. Focusing on the UA3, through this account are settled all the costs that are not covered from the aforementioned sources of inflow for the TSO, meaning the residual costs of Balancing Capacity, Balancing Energy and possible residual costs from TSO's transactions with other institutions (i.e., HEnEx) regarding energy trading. The cost of Imbalances is spitted to the MPs according to the imbalances that are caused from their represented entities, while the costs of UA1, UA2 and UA3 is shared to the BSPs according to the metered demand share of their represented entities (*pro-rata*).

3.1.1 Balancing Market Cost Analysis

In Table 3.2 the data that are presented derive from the official weekly reports of the TSO [62], regarding the Activated Balancing Energy and Settlement Prices. It is noted that the data considered, refer to the initial settlement (W+1) of the Balancing Market. Also, regarding the downwards Activated Energy the "minus" sign corresponds to remuneration of the respective BSP. The Balancing Market Cost refer to the cost of the Balancing Energy and the Balancing Capacity. The Balancing Energy is remunerated partly by the imbalance costs of MPs as described above and partly by the Uplift Account 3.

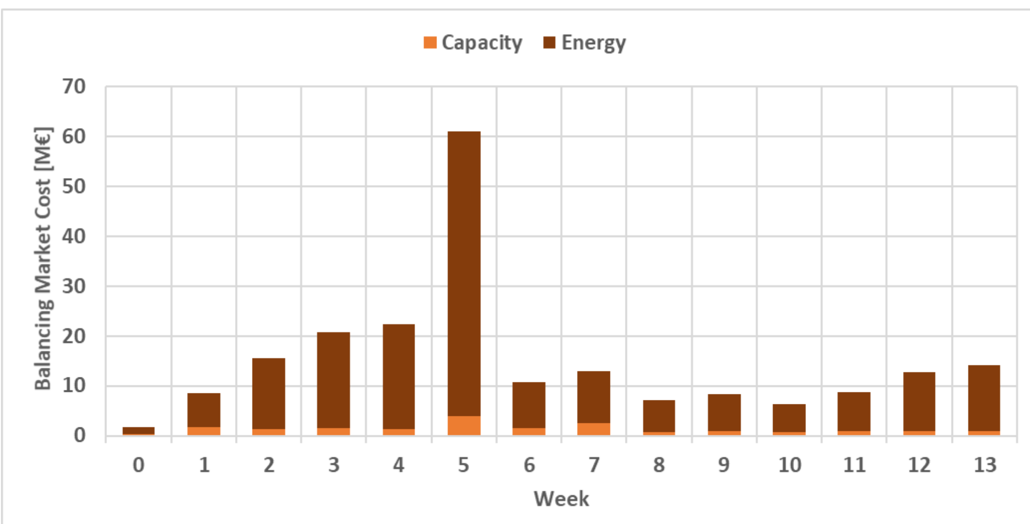


Figure 3.1. Balancing Market Cost considering Balancing Energy and Balancing Capacity Costs

As it can be seen in Figure 3.1 the cost of Balancing Capacity is an essentially small percentage of the total Balancing Market cost. This is explained by the fact that the respective cost is resulted considering predefined needs in Capacity volumes and the remuneration is realized based on the pay-as-bid logic. On the other hand, the cost of Balancing Energy is a greater part of the total Balancing Market cost and therefore, the current study will focus more on the elements that formulate the Balancing Energy cost.

Table 3.2. Balancing Energy Cost – Results based on ADMIE official weekly report

Week	Period	BSPs Act.En.Up Inflows [M€]	BSPs Act.En.Dn Outflows [M€]	BSPs Balancing Capacity Inflows [M€]	Total Balancing Energy Cost [M€]	Total Balancing Cost (Capacity + Energy) [M€]
0	01.11.2020	1.55	0.16	0.26	1.39	1.64
1	02.11.2020-08.11.2020	7.69	0.80	1.69	6.89	8.58
2	09.11.2020-15.11.2020	11.33	-2.77	1.40	14.10	15.50
3	16.11.2020-22.11.2020	11.94	-7.29	1.58	19.23	20.81
4	23.11.2020-29.11.2020	14.71	-6.28	1.35	20.99	22.34
5	30.11.2020-06.12.2020	52.66	-4.49	3.98	57.15	61.13
6	07.12.2020-13.12.2020	8.36	-0.82	1.59	9.18	10.77
7	14.12.2020-20.12.2020	9.87	-0.51	2.56	10.38	12.94
8	21.12.2020-27.12.2020	5.29	-1.16	0.75	6.45	7.20
9	28.12.2020-03.01.2021	3.60	-3.84	0.93	7.44	8.38
10	04.01.2021-10.01.2021	4.10	-1.54	0.74	5.64	6.37
11	11.01.2021-17.01.2021	6.61	-1.21	0.98	7.82	8.80
12	18.01.2021-24.01.2021	9.79	-2.13	0.90	11.93	12.83
13	25.01.2021-31.01.2021	11.86	-1.41	0.82	13.27	14.09

For the respective period (01.11.2020-31.01.2021) under study, the statistical analysis on the weekly total cost of the Balancing Market shows that this was resulted between 6.37M€. on week 10 (04.01.2021-10.01.2021), and 61.13M€ on week 5 (30.11.2020-06.12.2020).

The analytical public data of the Imbalance Settlement Procedure results that are provided from the TSO's official website [62], in a weekly basis, with a time resolution of 15-min, are analyzed and presented on a weekly and daily resolution. Applying the equations $(3.1) - (3.4)$ on the public raw data, the daily uplift costs are resulted as presented in Figure 3.2, where the cost of UA3 on 02.12.2020 reached 76.27€/MWh and the total sum of Uplift Accounts cost reached 88.07€/MWh.

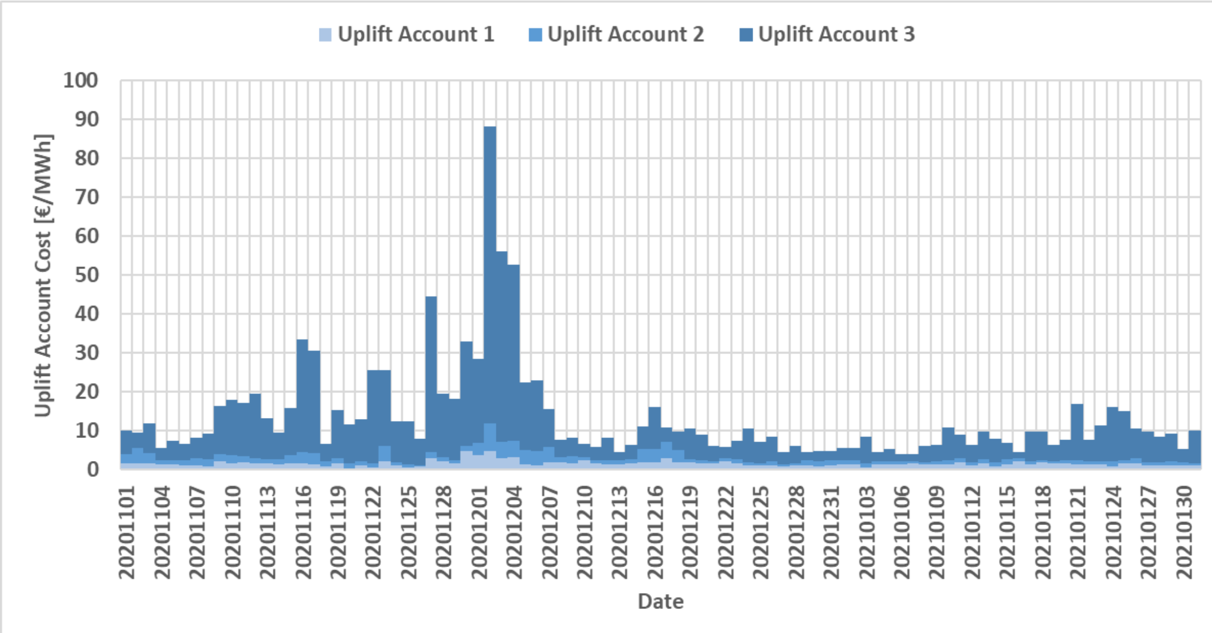


Figure 3.2. Daily Uplift Accounts Cost

$$Uplift\_Account\_1_{day} = \frac{1}{96}\sum_{sp=1}^{96} Uplift\_Account\_1_{sp}^{day} \tag{3.1}$$

$$Uplift\_Account\_2_{day} = \frac{1}{96}\sum_{sp=1}^{96} Uplift\_Account\_2_{sp}^{day} \tag{3.2}$$

$$Uplift\_Account\_3_{day} = \frac{1}{96}\sum_{sp=1}^{96} Uplift\_Account\_3_{sp}^{day} \tag{3.3}$$

$$Uplift\_Accounts_{day}^{Total} = Uplift\_Account\_1_{day} + Uplift\_Account\_2_{day} + Uplift\_Account\_3_{day} \tag{3.4}$$

Applying the equations $(3.5) - (3.8)$ to the Imbalance Settlement Procedure data [62], the weekly uplift costs are resulted as presented in Table 3.3 and illustrated in Figure 3.3, where the higher price of total Uplift Accounts Cost is resulted at 43.37€/MWh with UA1=3.16€/MWh, UA2=3.84€/MWh, UA3=36.37€/MWh and corresponds to week 5. The lowest price of total Uplift Accounts Cost is resulted at 5.74€/MWh, where UA1=1.12€/MWh, UA2=1.09€/MWh, UA1=3.53€/MWh and corresponds to week 9. In the same Figure is also illustrated the total Balancing Market Cost, where it is shown how the Uplift Accounts Cost per week is correlated to the Cost of Balancing Market.

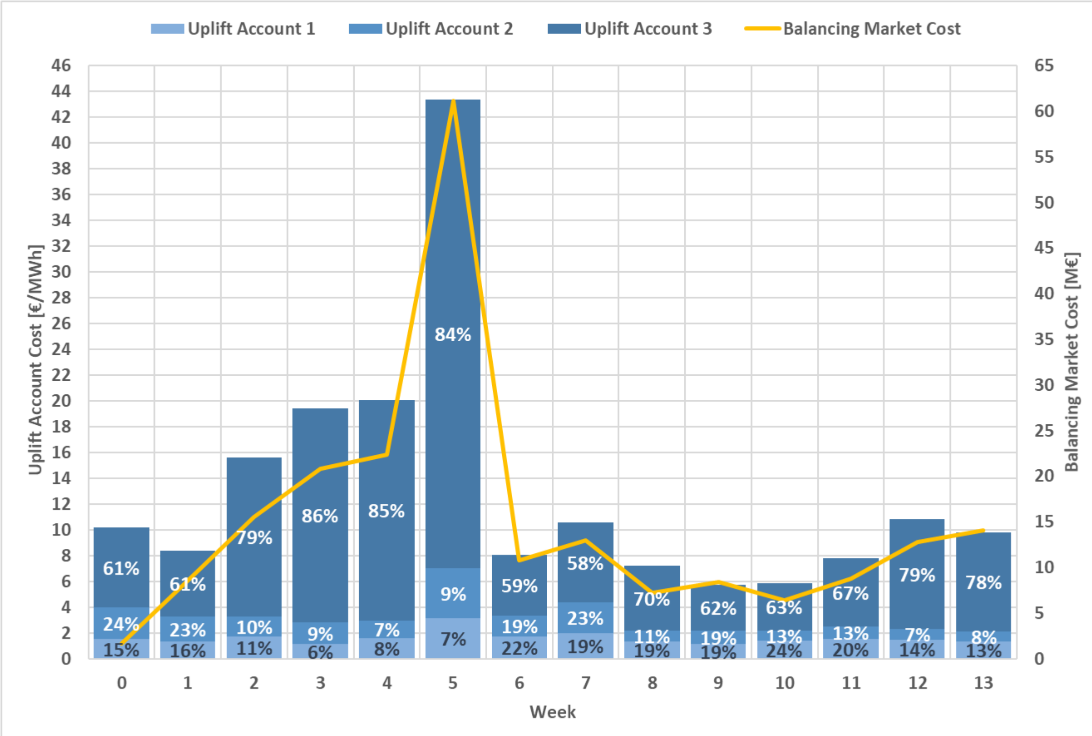


Figure 3.3. Weekly Uplift Accounts Cost to Total Balancing Market Cost

$$Uplift\_Account\_1_{week} = \frac{1}{doW * 96} \sum_{day=1}^{doW} \sum_{sp=1}^{96} Uplift\_Account\_1_{sp}^{day} \tag{3.5}$$

$$Uplift\_Account\_2_{week} = \frac{1}{doW * 96} \sum_{day=1}^{doW} \sum_{sp=1}^{96} Uplift\_Account\_2_{sp}^{day} \tag{3.6}$$

$$Uplift\_Account\_2_{week} = \frac{1}{doW * 96} \sum_{day=1}^{doW} \sum_{sp=1}^{96} Uplift\_Account\_2_{sp}^{day} \tag{3.7}$$

$$Uplift\_Accounts_{week}^{Total} = Uplift\_Account\_1_{week} + Uplift\_Account\_2_{week} + Uplift\_Account\_3_{week} \tag{3.8}$$

The total volumes of upwards and downwards activated energy that are presented in Table 3.3 are calculated by applying equations (3.9) – (3.12). Applying the equations (3.11) and (3.12) the total absolute of activated energy and the net activated energy per week are calculated respectively, whereas by applying equation (3.13) the index that corresponds to the ratio of net to total activated energy is defined.

$$Act.En.Up_{week} = \sum_{day=1}^{doW} \sum_{sp=1}^{96} Act.En.Up_{sp}^{day} \tag{3.9}$$

$$Act.En.Dn_{week} = \sum_{day=1}^{doW} \sum_{sp=1}^{96} Act.En.Dn_{sp}^{day} \tag{3.10}$$

$$Act.En._{week}^{Total} = |Act.En.Up_{week}| + |Act.En.Dn_{week}| \tag{3.11}$$

$$Act.En._{week}^{Net} = |Act.En.Up_{week}| - |Act.En.Dn_{week}| \tag{3.12}$$

$$Act.En._{week}^{Net\ to\ Total} = \frac{|Act.En_{week}^{Net}|}{|Act.En_{week}^{Total}|}\% \tag{3.13}$$

Table 3.3. Weekly Settlement Procedure results

week	PERIOD	Activated Balancing Energy Up [MWh]	Activated Balancing Energy Down [MWh]	Total Activated Balancing Energy (net) [MWh]	Total Activated Balancing Energy (absolute sum) [MWh]	Uplift Account 1 [€/MWh]	Uplift Account 2 [€/MWh]	Uplift Account 3 [€/MWh]	Total Uplift Accounts Cost [€/MWh]
0	01.11.2020	10,274	10,936	-662	21,210	1.55	2.44	6.19	**10.17**
1	02.11.2020-08.11.2020	74,678	69,617	5,061	144,295	1.34	1.94	5.09	**8.37**
2	09.11.2020-15.11.2020	67,429	68,476	-1,047	135,905	1.71	1.60	12.32	**15.63**
3	16.11.2020-22.11.2020	61,913	86,690	-24,777	148,604	1.12	1.69	16.64	**19.44**
4	23.11.2020-29.11.2020	60,549	81,889	-21,339	142,438	1.62	1.35	17.09	**20.06**
5	30.11.2020-06.12.2020	118,240	91,608	26,632	209,848	3.16	3.84	36.37	**43.37**
6	07.12.2020-13.12.2020	71,341	58,173	13,168	129,515	1.75	1.56	4.77	**8.09**
7	14.12.2020-20.12.2020	74,874	63,872	11,002	138,746	1.96	2.42	6.17	**10.55**
8	21.12.2020-27.12.2020	51,517	82,427	-30,910	133,943	1.34	0.81	5.03	**7.18**
9	28.12.2020-03.01.2021	37,386	97,332	-59,946	134,718	1.12	1.09	3.53	**5.74**
10	04.01.2021-10.01.2021	38,676	77,547	-38,872	116,223	1.39	0.79	3.69	**5.88**
11	11.01.2021-17.01.2021	63,262	81,331	-18,068	144,593	1.54	0.99	5.24	**7.77**
12	18.01.2021-24.01.2021	80,862	110,844	-29,982	191,706	1.48	0.81	8.54	**10.82**
13	25.01.2021-31.01.2021	98,887	90,970	7,917	189,857	1.32	0.81	7.69	**9.82**

The activated energy volumes are shown in Figure 3.4 both for upwards and downwards activation, as well as the net imbalance energy. For five consecutive weeks (8-12) the net balancing energy corresponds to downwards direction. Also, the highest net imbalance is shown in week 9 and corresponds to downwards energy. The larger quantities of upwards balancing energy are resulted in week 5 and for downwards balancing energy are resulted on week 12.

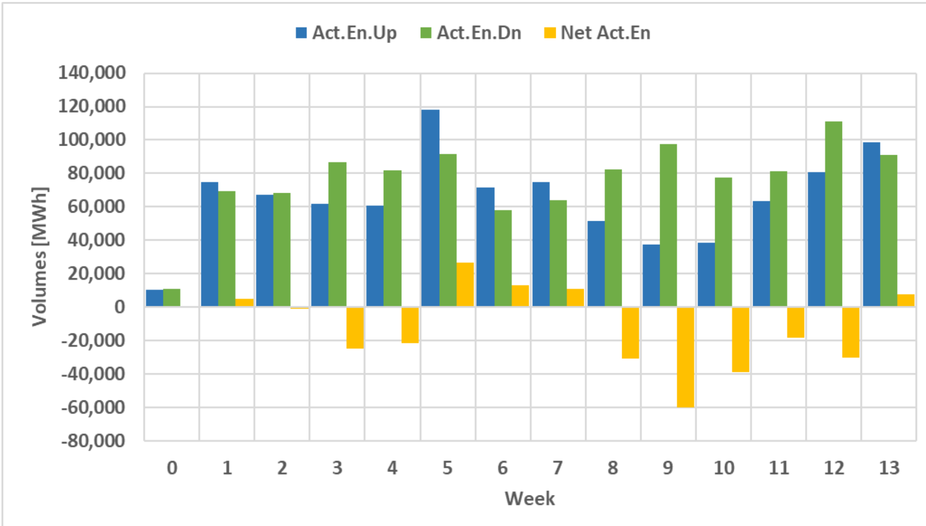


Figure 3.4. Activated Balancing Energy Volumes

Another illustration of the balancing volumes is shown in Figure 3.5, where the upwards and downwards activated energy (*right axis*) are presented simultaneously with the Balancing Energy Cost (*left axis*). As it can be seen from the respective Figure, the highest Balancing Energy Cost (57.15M€) is witnessed in week 5, when the total Activated Balancing Energy is maximum (209,848MWh), whereas in week 10, the Balancing Energy Cost is the lowest at 5.64M€ and as the total activated energy resulted to 116,223MWh.

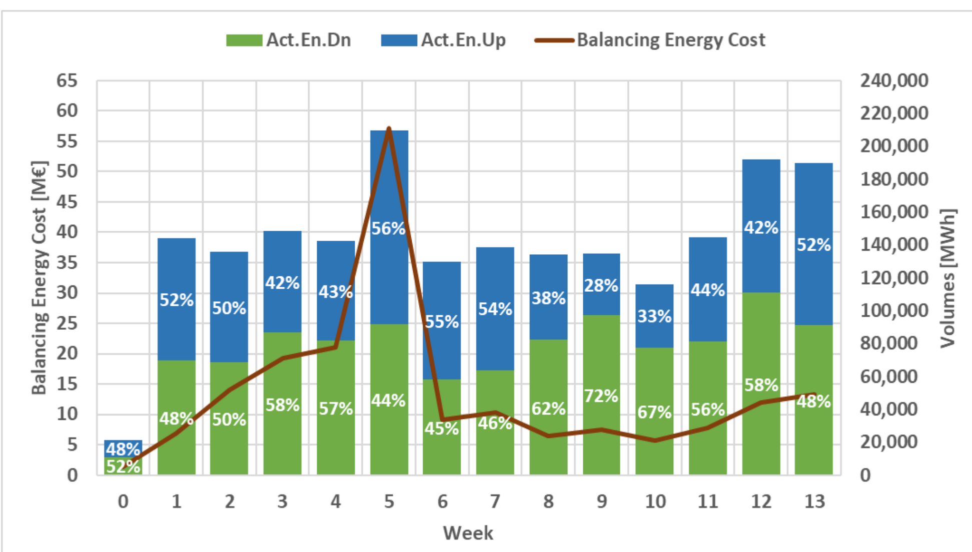


Figure 3.5. Total Uplift Cost and mFRR prices spread correlation

In Figure 3.6 it is shown the absolute sum of activated upwards and downwards volumes and the net imbalance volumes (*left axis*), simultaneously with the ratio of net to total activated energy (*right axis*) as calculated based on equation (3.13).

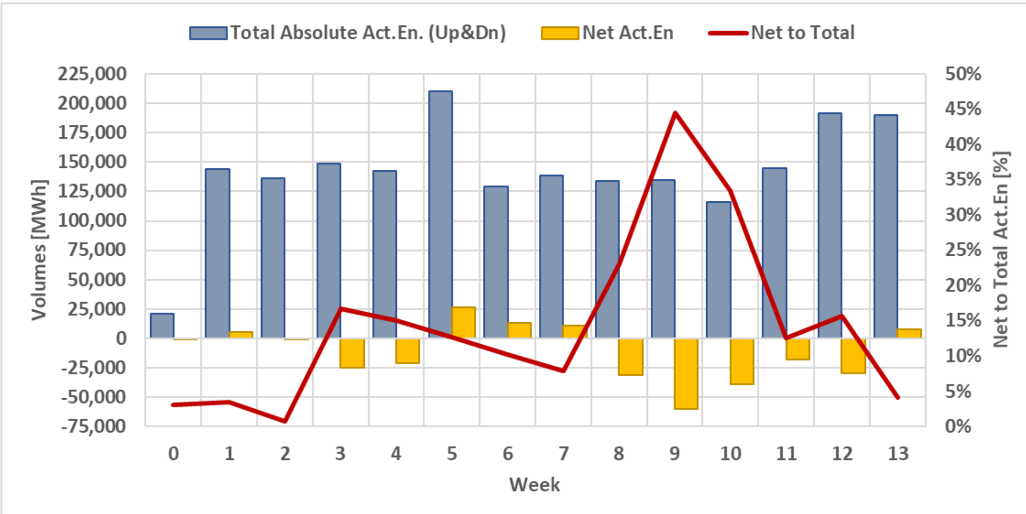


Figure 3.6. Total Absolute to Net Activated Balancing Energy

In Figure 3.7 the index of net to total ratio (*right axis*) is illustrated against the Balancing Energy cost (*left axis*), where it can be seen that for high percentages of the net to total ratio index, the Balancing Energy Cost is low (i.e., in week 9 the ratio was 44% and the Balancing Energy Cost was equal to 7.44M€, whereas in week 7 the ratio was 8% and the Balancing Energy Cost was equal to 10.38M€).

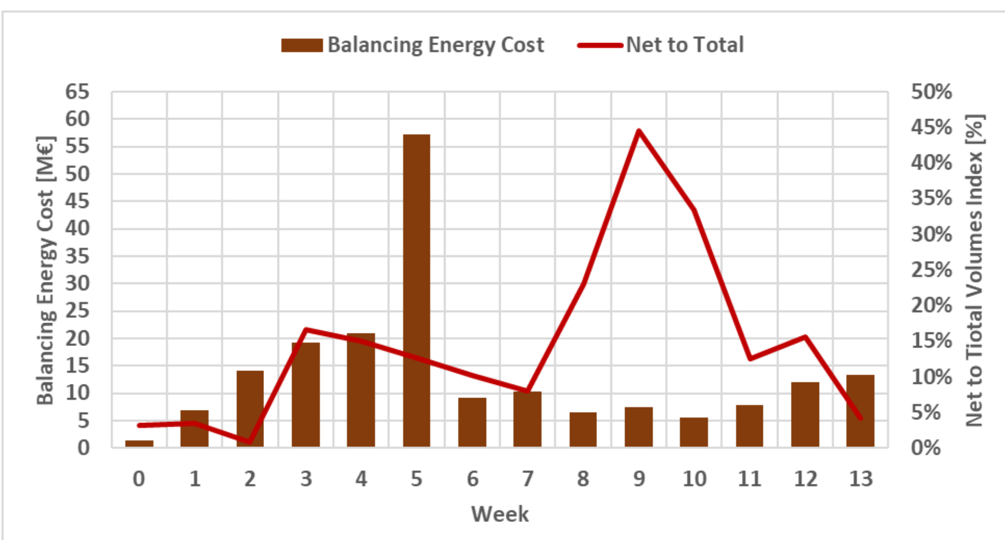


Figure 3.7. Net to Total Index Correlation with Balancing Energy Cost

In the scope of this analysis the Balancing Energy Cost can be estimated based on total activated volumes and the mFRR marginal prices, by applying the equations $(3.14)-(3.17)$. The correlation between the Balancing Energy Cost based on mFRR marginal prices and the final cost according to TSO's official report is presented in Figure 3.8, where is is shown the validity of the calculations.

$$Cost\ of\ Act.En.Up_{day}^{mFRR} = \sum_{sp=1}^{96} Act.En.Up_{sp}^{day} * mFRRup\_price_{sp}^{day} \tag{3.14}$$

$$Cost\ of\ Act.En.Dn_{day}^{mFRR} = \sum_{sp=1}^{96} Act.En.Dn_{sp}^{day} * mFRRdn\_price_{sp}^{day} \tag{3.15}$$

$$Cost\ of\ Act.En.Up_{week}^{mFRR} = \sum_{day=1}^{doW} Cost\ of\ Act.En.Up_{day}^{mFRR} \tag{3.16}$$

$$Cost\ of\ Act.En.Dn_{week}^{mFRR} = \sum_{day=1}^{doW} Cost\ of\ Act.En.Dn_{day}^{mFRR} \tag{3.17}$$

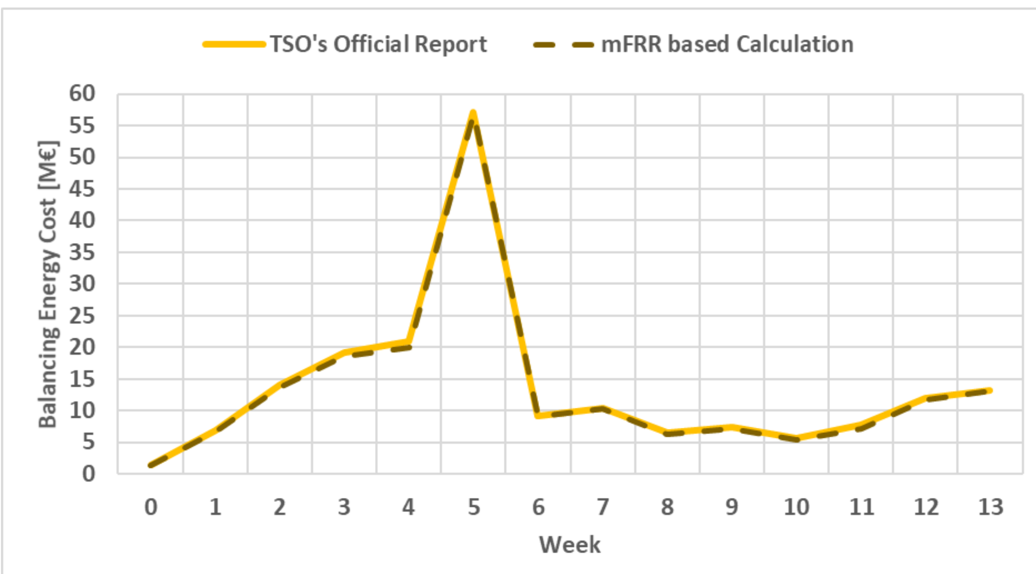


Figure 3.8. Balancing Energy Cost Calculations using mFRR prices

As the calculation of the Balancing Energy Cost based on the mFRR marginal prices is validated from the above analysis as shown in Figure 3.8, the balancing energy cost can be estimated on a daily resolution as it is presented in Figure 3.9.

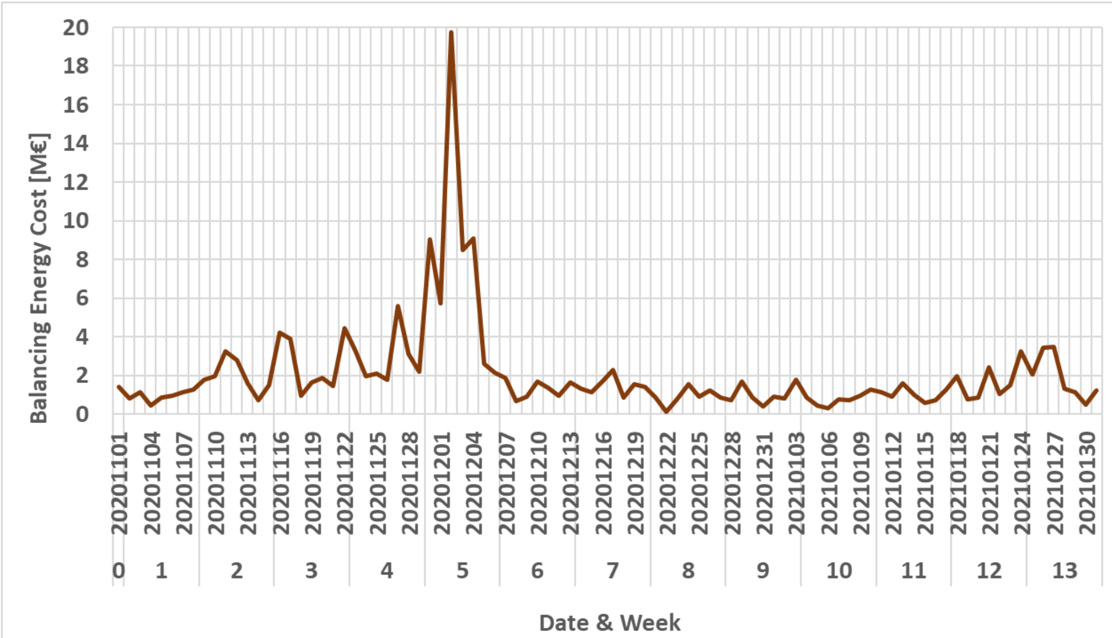


Figure 3.9. Daily Balancing Energy Cost based on mFRR prices

3.1.2 Statistical Analysis on weekly mFRR marginal Prices

The weekly spread of the marginal mFRR prices is calculated according to equations $(3.18) - (3.20)$, where sp stands for "settlement period" and doW stands for "days of week". The mFRR spread is an index that models the prices fluctuations and ultimately, provides a signal for the Balancing Energy Cost as illustrated in Figure 3.10, where the correlation between the mFRR marginal prices spread and the Balancing Energy Cost is obvious.

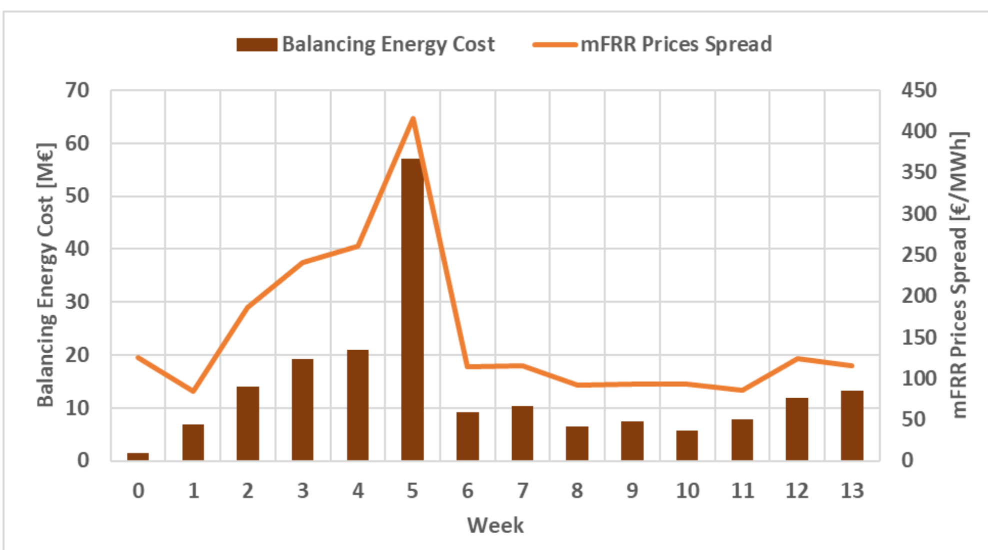


Figure 3.10. Correlation of weekly mFRR Prices Spread to Balancing Energy Cost

$$mFRR\_pr\_spread_{sp} = mFRR\_pr_{sp}^{Up} - mFRR\_pr_{sp}^{Dn} \tag{3.18}$$

$$mFRR\_spread_{day} = \frac{1}{96}\sum_{sp=1}^{96} mFRR\_pr_{sp}^{Up} - mFRR\_pr_{sp}^{Dn} \tag{3.19}$$

$$mFRR\_pr\_spread_{week} = \frac{1}{doW * 96}\sum_{day=1}^{doW}\sum_{sp=1}^{96} mFRR\_pr_{sp}^{Up} - mFRR\_pr_{sp}^{Dn} \tag{3.20}$$

In the following section the results of the statistical analysis on mFRR marginal prices are presented, on a weekly resolution. For the analysis, there are used the resulted data from the first Clearing (W+1) of the Imbalance Settlement Procedure as published on the official TSO's website [62]. On every figure of each week there are presented on the left axis the frequency of mFRR prices settled per cluster (price range) and on the right axis it is presented the average activated volumes of balancing energy that correspond to the respective cluster of mFRR prices.

The count of the mFRR marginal prices per cluster, for upwards and downwards activated balancing energy, is set according to (3.21) and (3.22), respectively. Subsequently, the frequency of appearance per cluster is calculated according to (3.24) and (3.24), where doW stands "for days of week". Finally, the average volumes of activated energy are estimated according to equations (3.25) and (3.26).

$$if\ Act.En.Up_{sp} \exists\ cluster_i^{up}\ then\ count_{cluster}^{up} = count_{cluster}^{up} + 1 \tag{3.21}$$

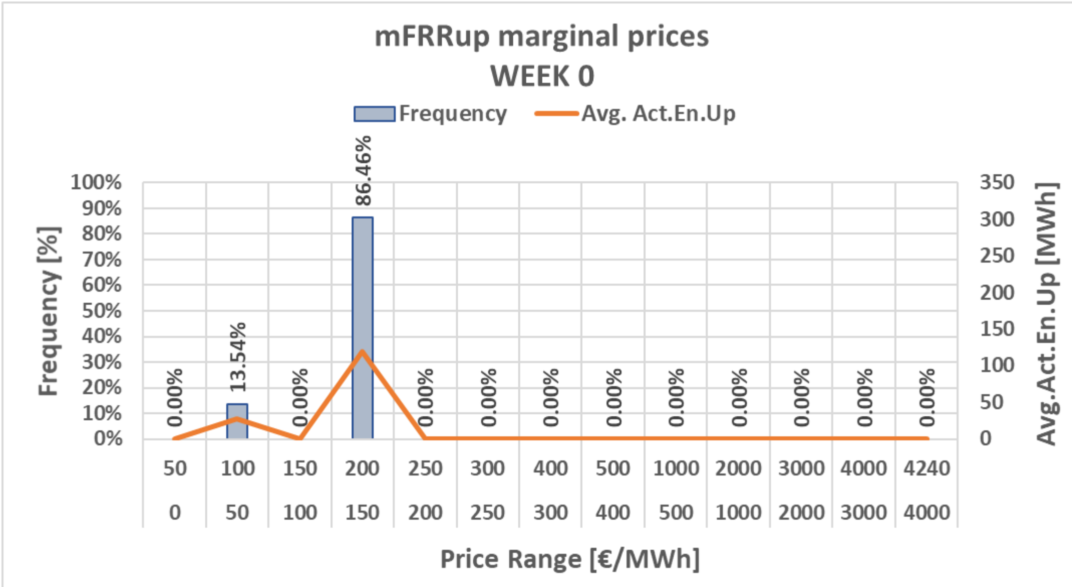
$$if\ Act.En.Dn_{sp} \exists\ cluster_i^{dn}\ then\ count_{cluster}^{dn} = count_{cluster}^{dn} + 1 \tag{3.22}$$

$$Frequency.Act.En.Up_{cluster}^{\%} = \frac{count_{cluster}^{up}}{96 * doW}\% \tag{3.23}$$

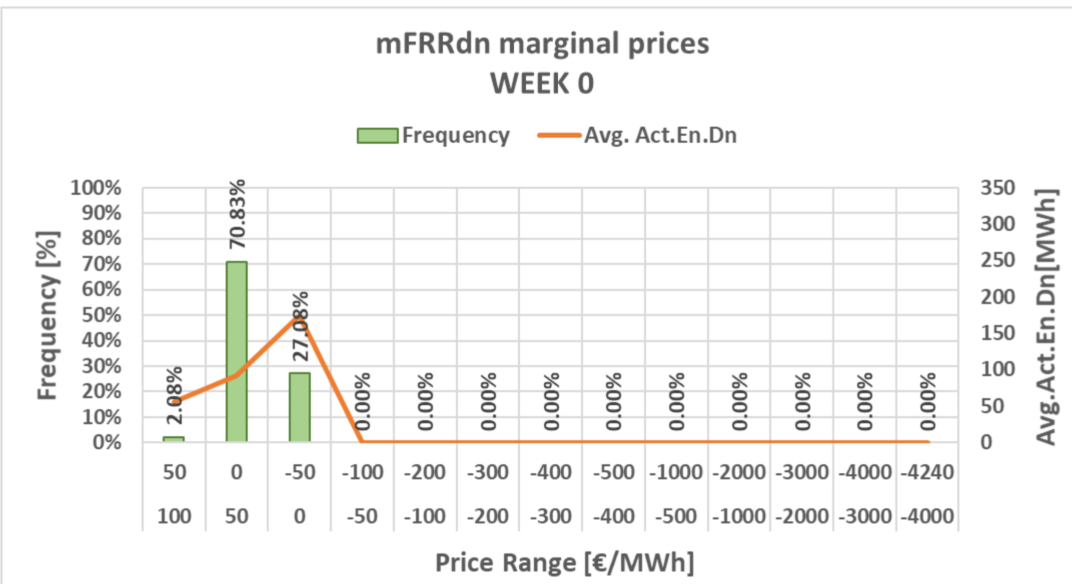
$$Frequency.Act.En.Dn_{cluster}^{\%} = \frac{count_{cluster}^{dn}}{96 * doW}\% \tag{3.24}$$

$$Avg.Act.En.Up_{cluster} = \frac{1}{count_{cluster}^{up}}\sum_{c=1}^{count_{cluster}^{up}} Act.En.Up_c^{cluster} \tag{3.25}$$

$$Avg.Act.En.Dn_{cluster} = \frac{1}{count_{cluster}^{dn}}\sum_{c=1}^{count_{cluster}^{dn}} Act.En.Dn_c^{cluster} \tag{3.26}$$

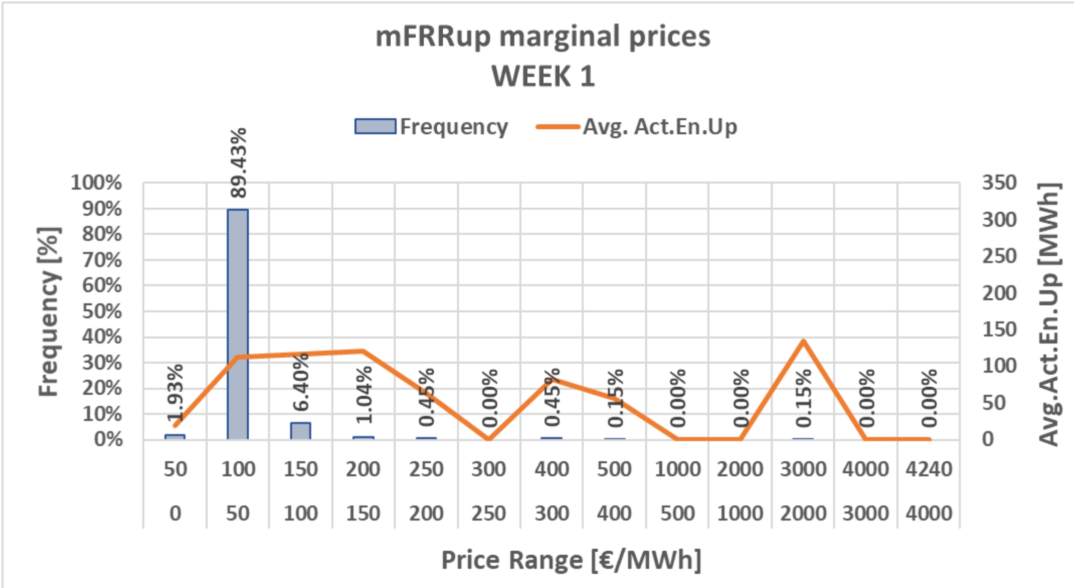


(a)



(b)

Figure 3.11. Week 0 – mFRR marginal prices; (a) Balancing Energy Up; (b) Balancing Energy Down



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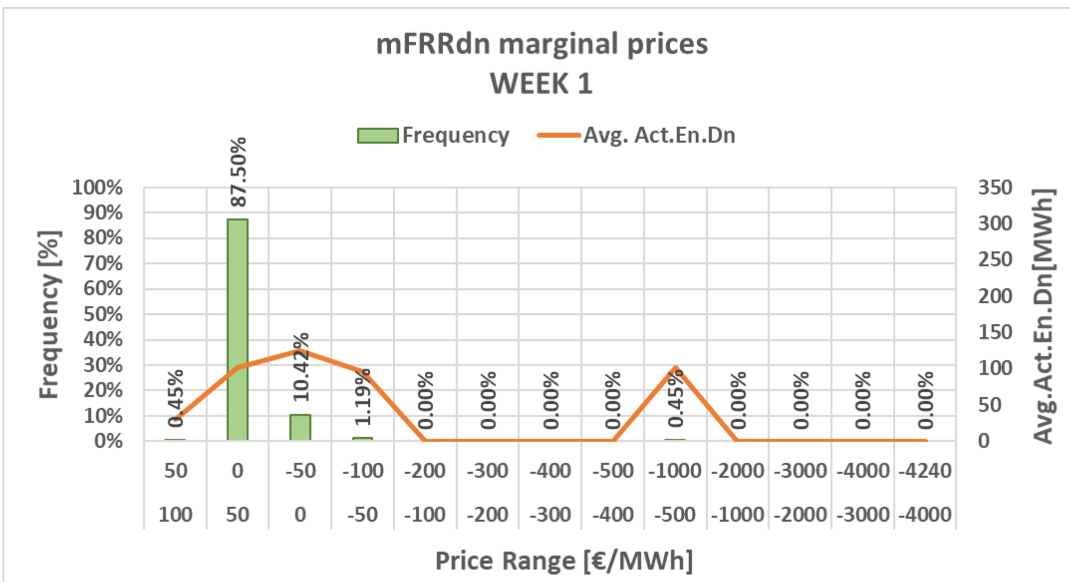
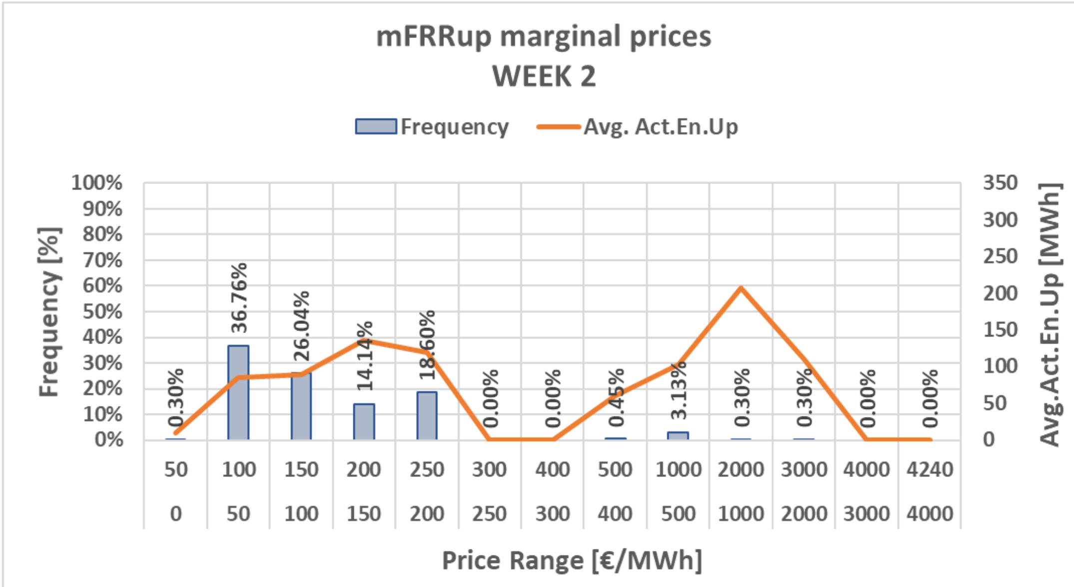


(b)

Figure 3.12. Week 1 – mFRR marginal prices; (a) Balancing Energy Up; (b) Balancing Energy Down



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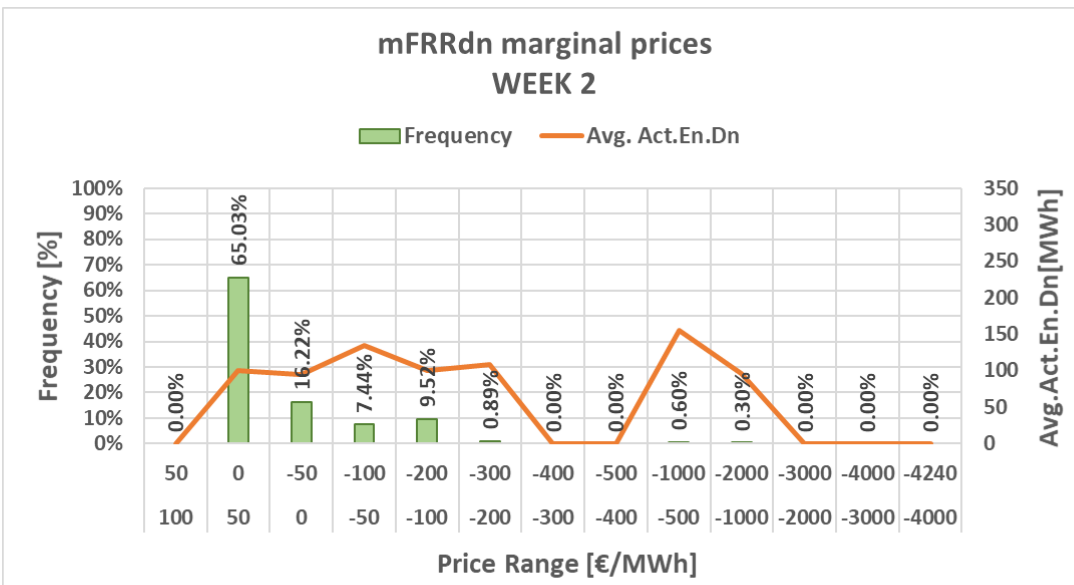
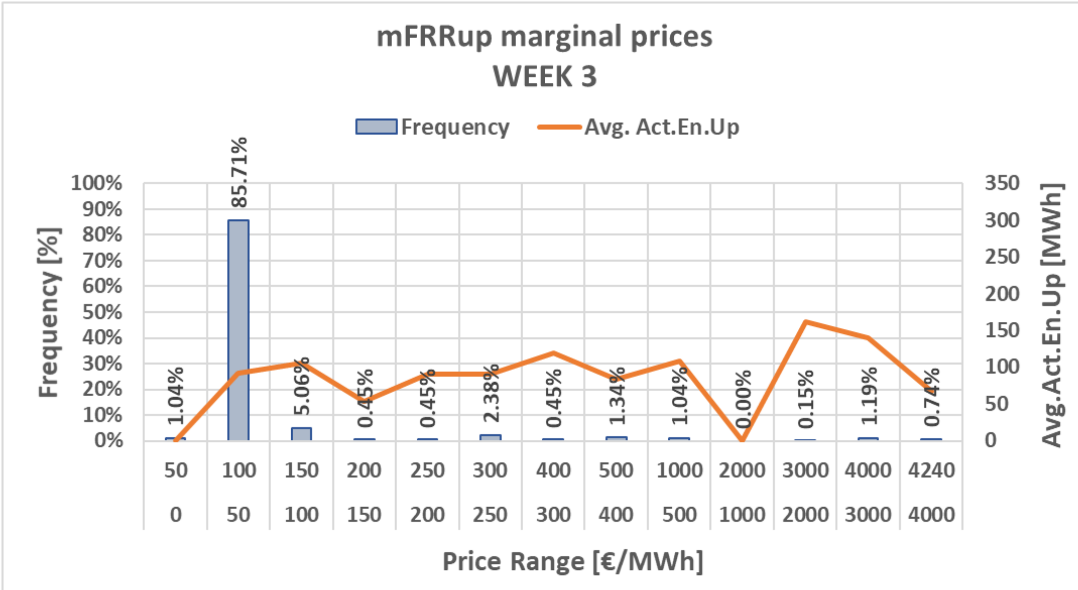


(b)

Figure 3.13. Week 2 – mFRR marginal prices; (a) Balancing Energy Up; (b) Balancing Energy Down



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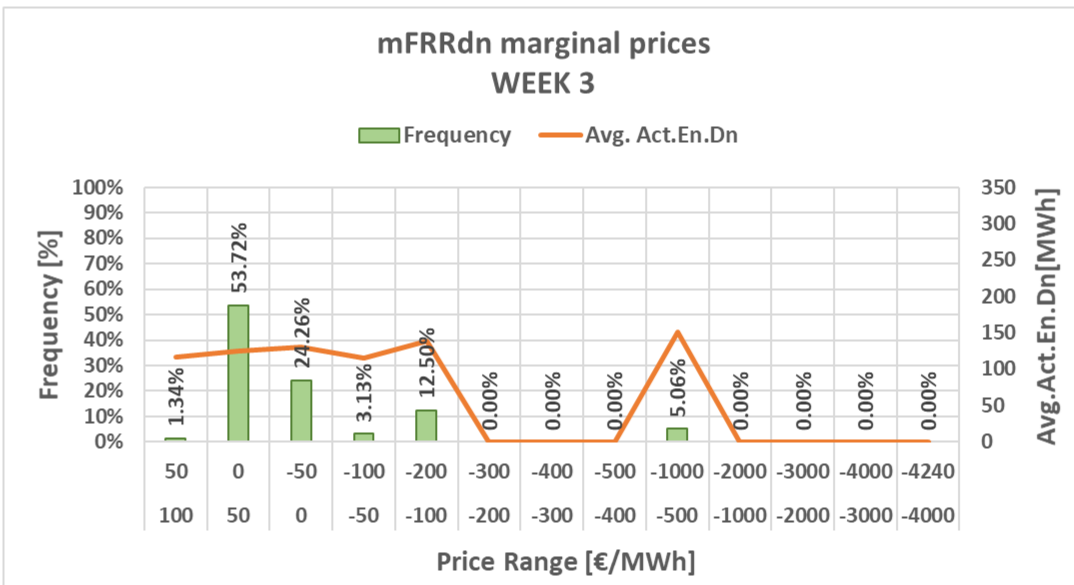
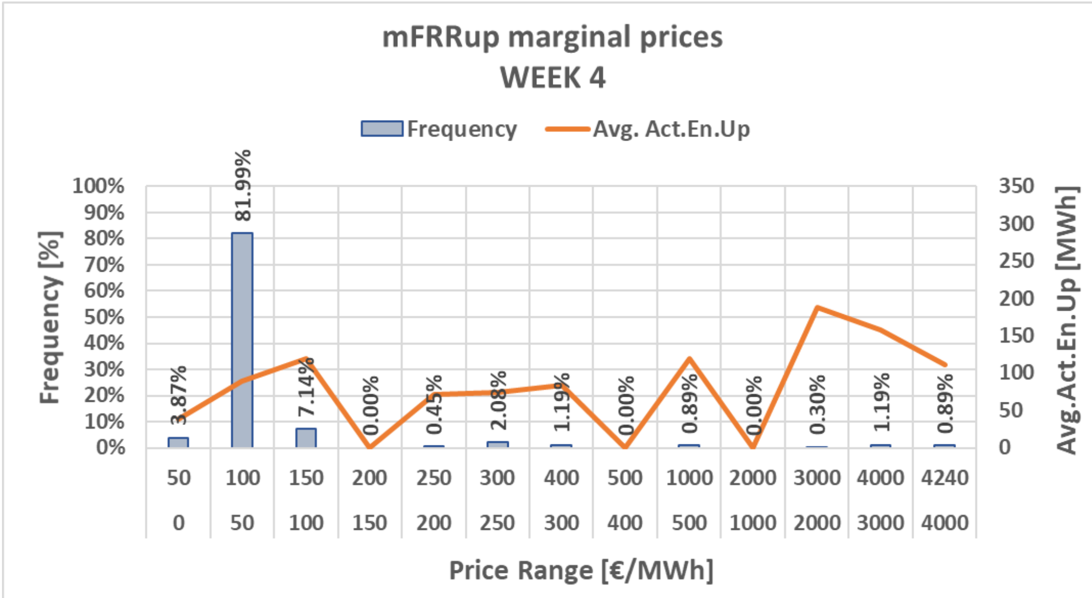


(b)

Figure 3.14. Week 3 – mFRR marginal prices; (a) Balancing Energy Up; (b) Balancing Energy Down



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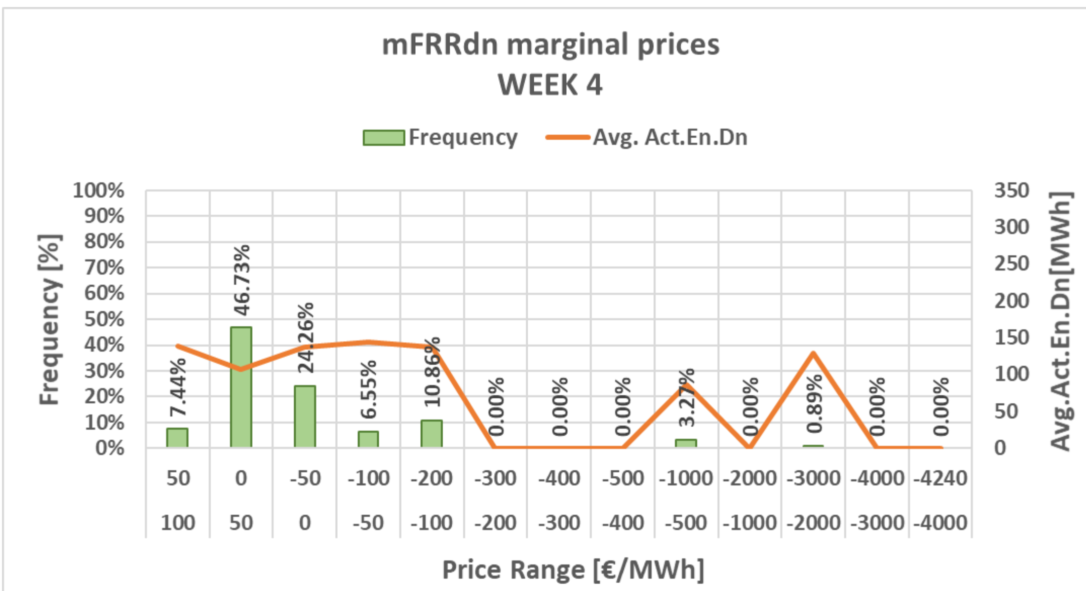
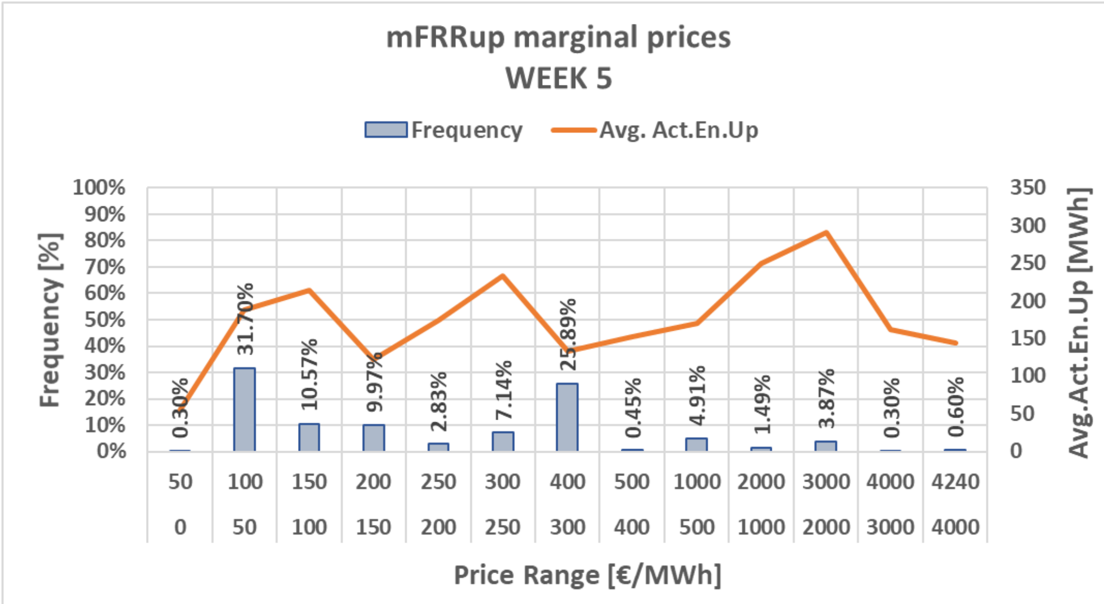
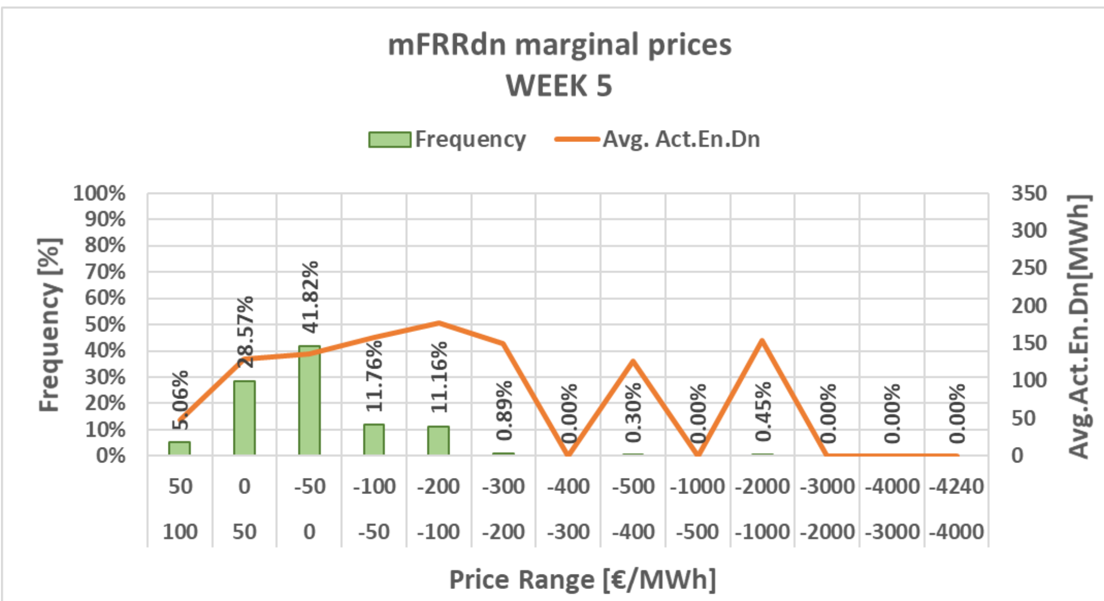


(b)

Figure 3.15. Week 4 – mFRR marginal prices; (a) Balancing Energy Up; (b) Balancing Energy Down

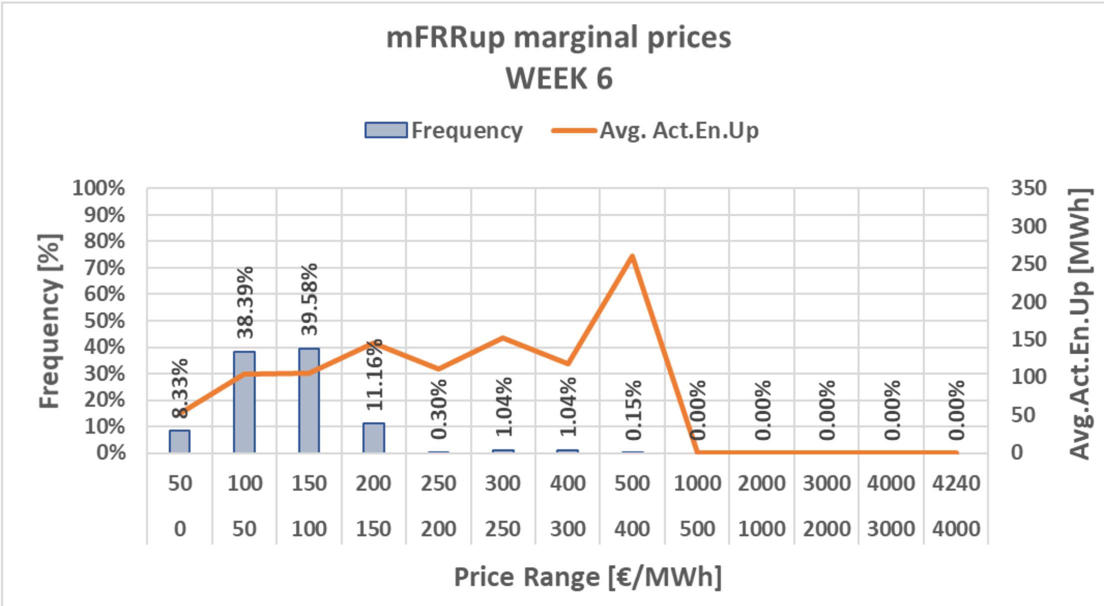


(a)



(b)

Figure 3.16. Week 5 – mFRR marginal prices; (a) Balancing Energy Up; (b) Balancing Energy Down



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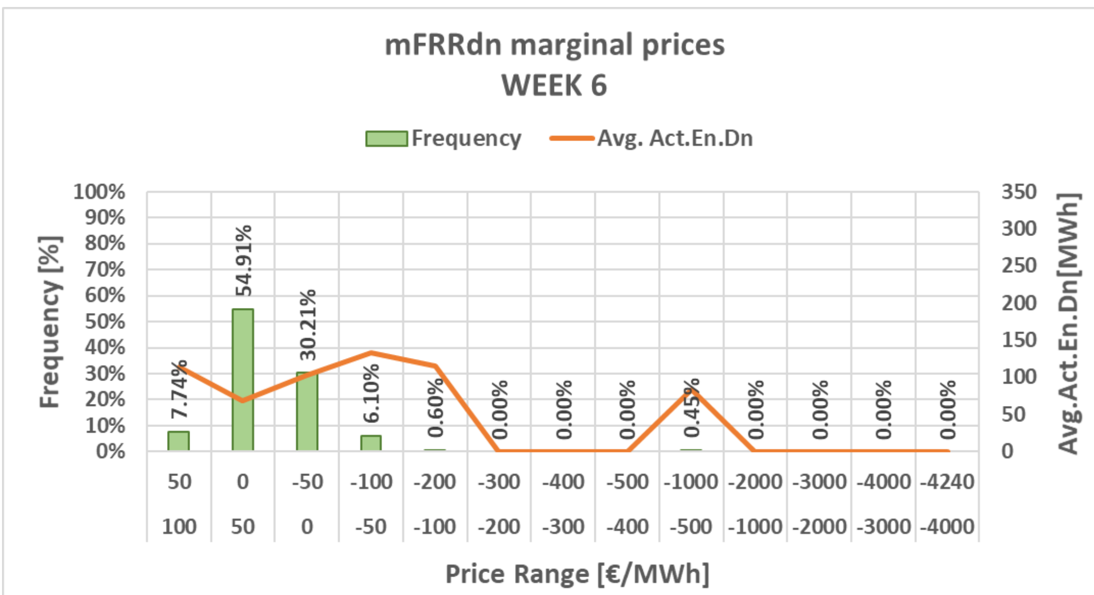
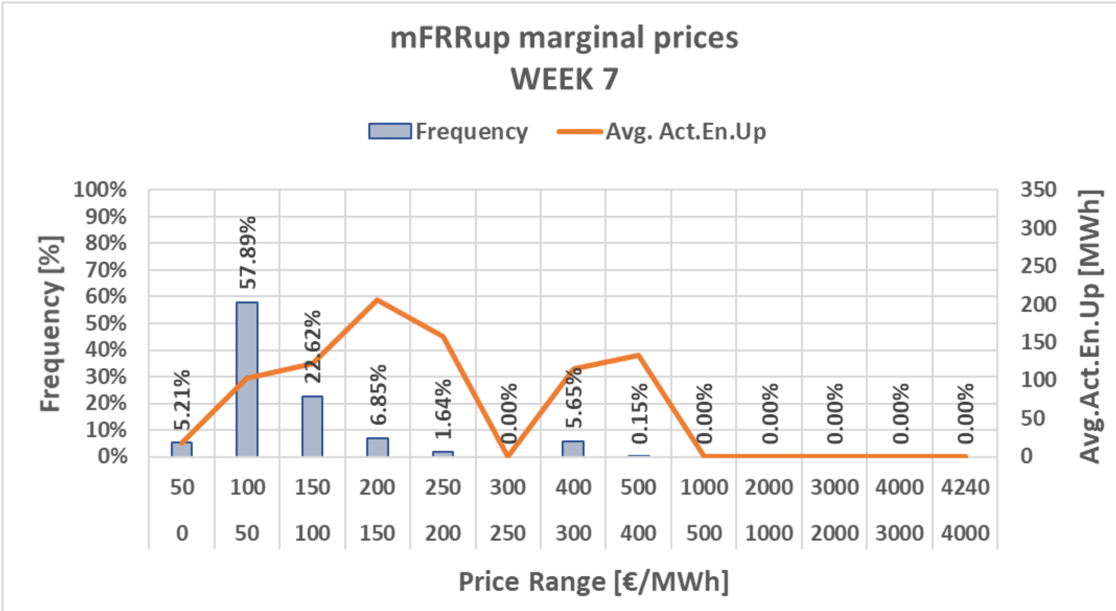


(b)

Figure 3.17. Week 6 – mFRR marginal prices; (a) Balancing Energy Up; (b) Balancing Energy Down



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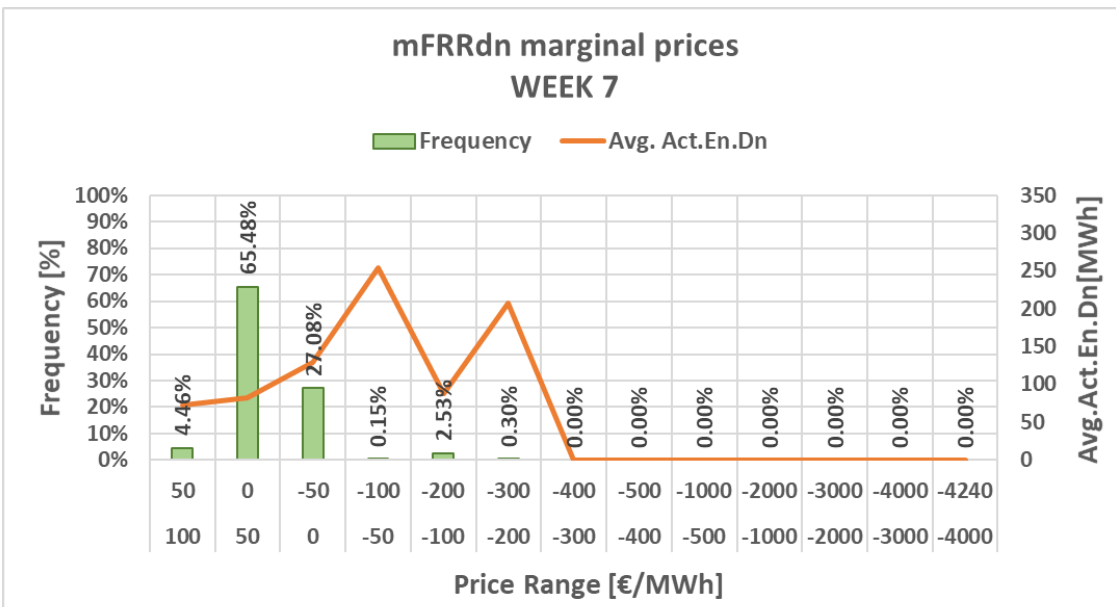
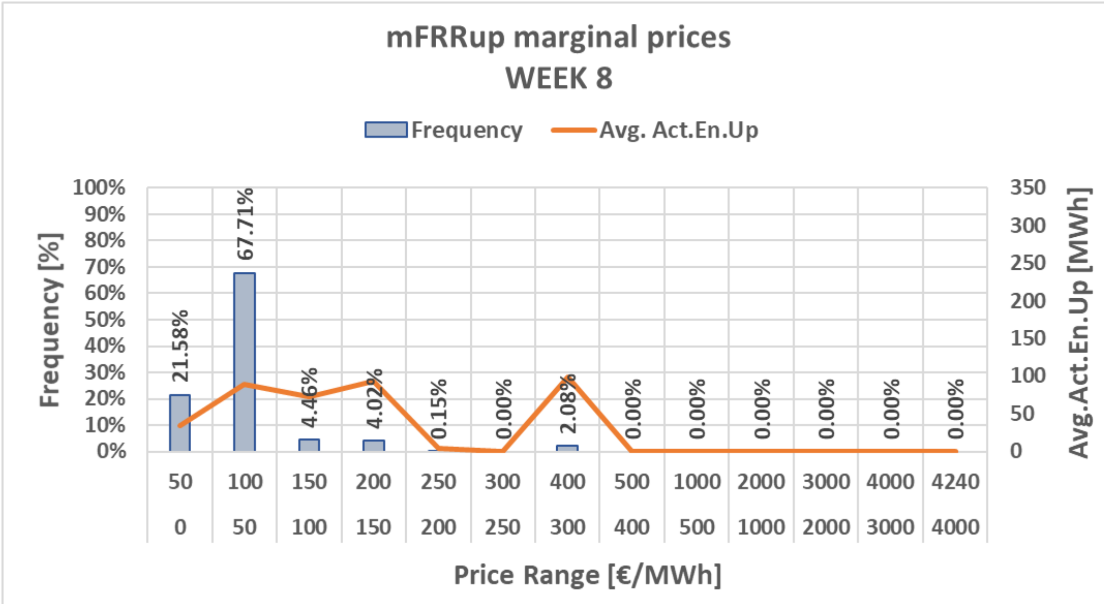


(b)

Figure 3.18. Week 7 – mFRR marginal prices; (a) Balancing Energy Up; (b) Balancing Energy Down



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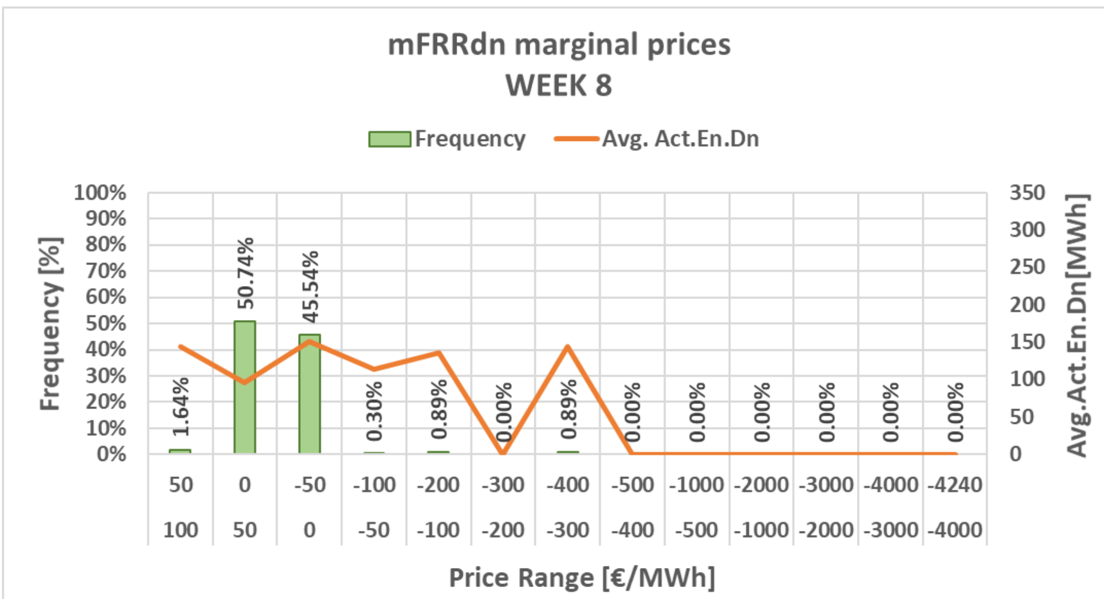
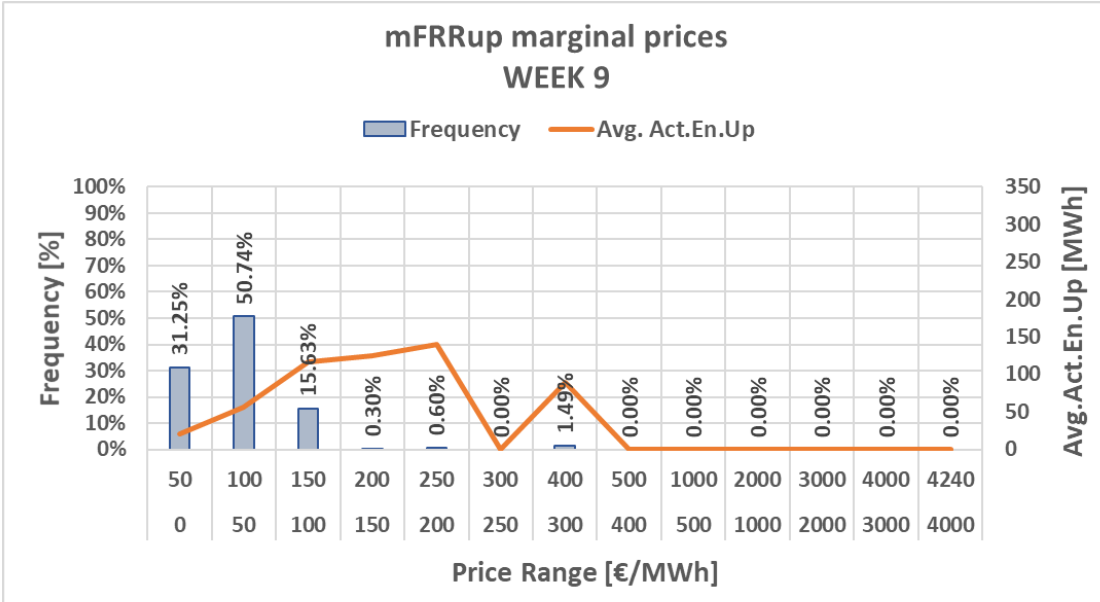


(b)

Figure 3.19. Week 8 – mFRR marginal prices; (a) Balancing Energy Up; (b) Balancing Energy Down



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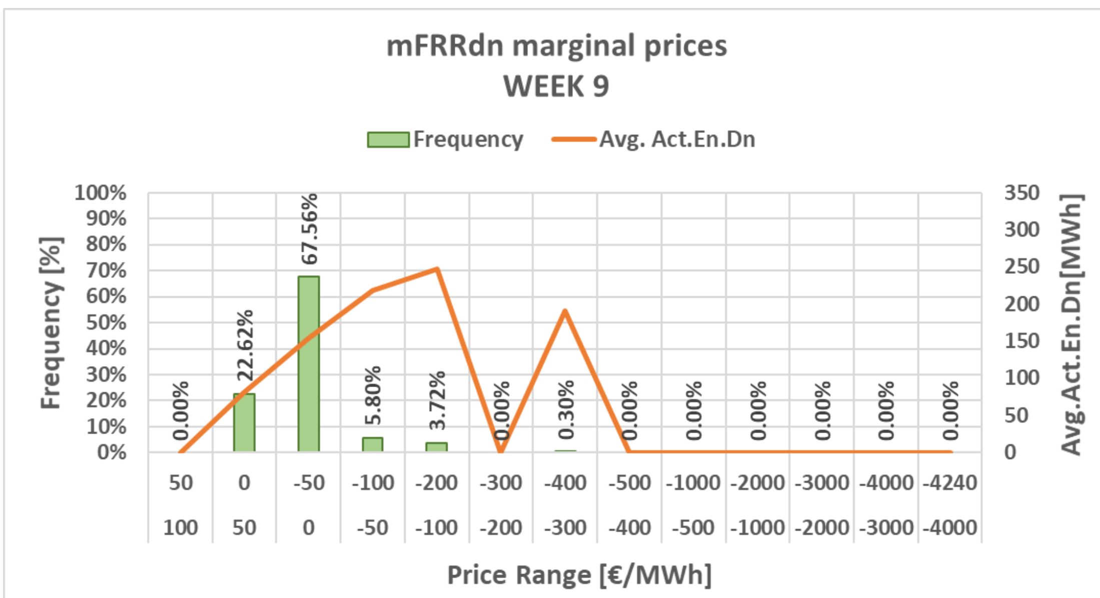
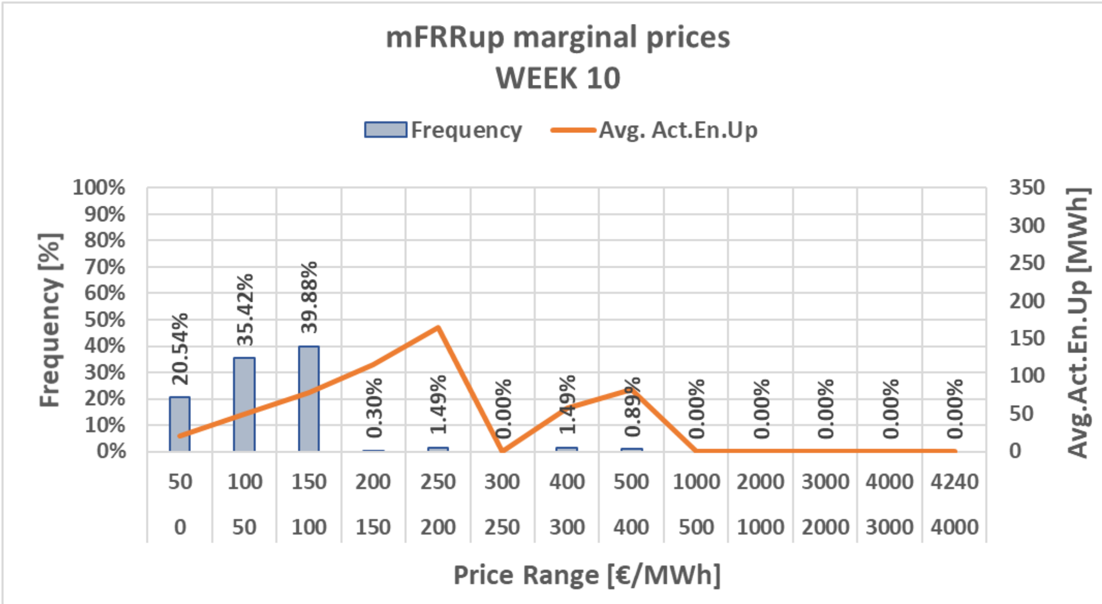
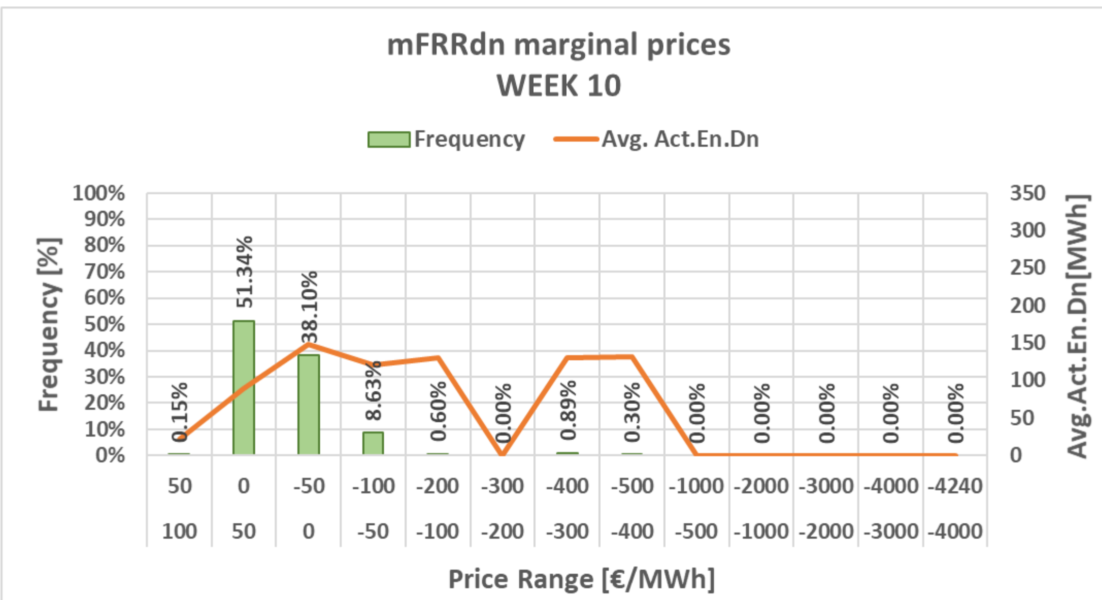


(b)

Figure 3.20. Week 9 – mFRR marginal prices; (a) Balancing Energy Up; (b) Balancing Energy Down

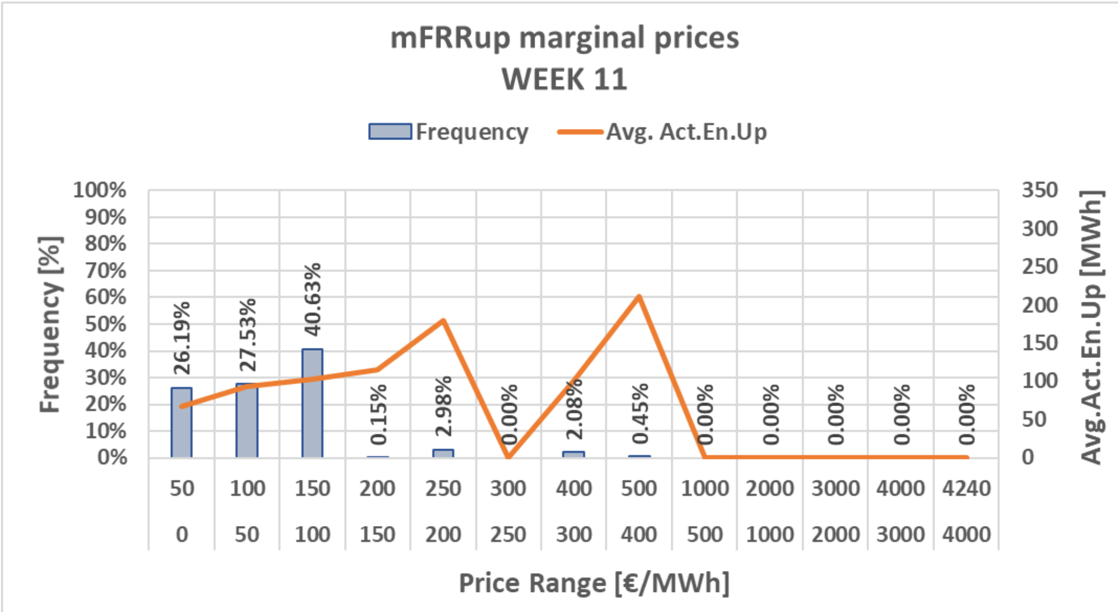


(a)



(b)

Figure 3.21. Week 10 – mFRR marginal prices; (a) Balancing Energy Up; (b) Balancing Energy Down



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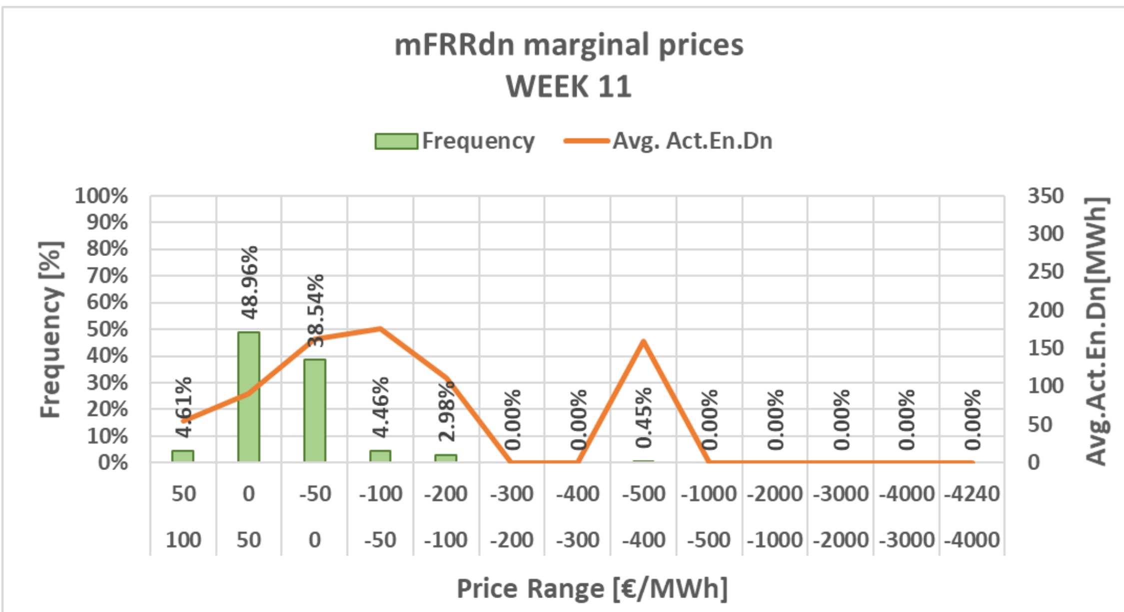
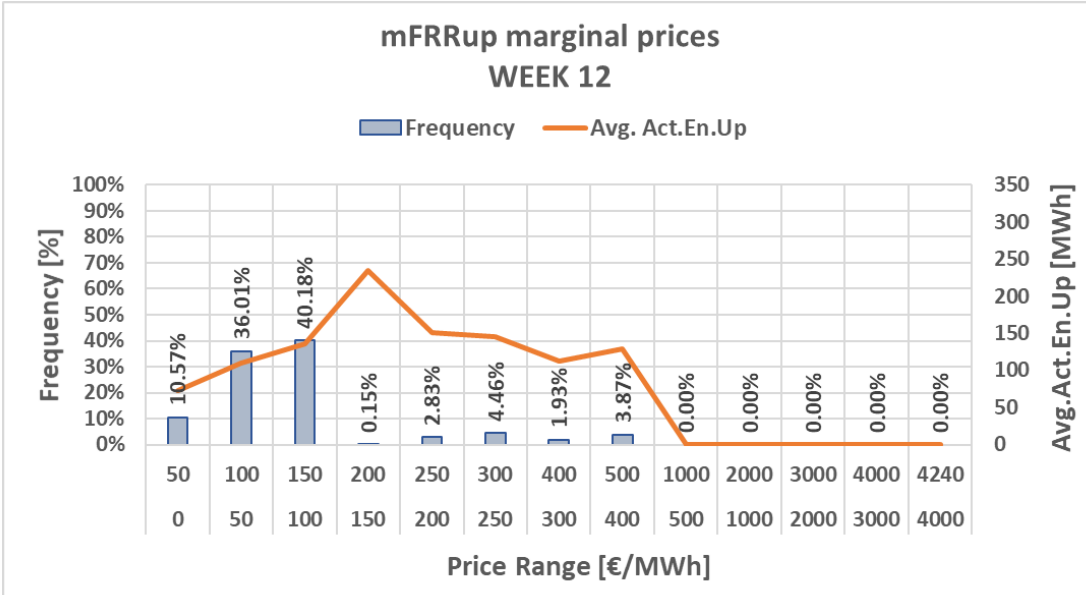


(b)

Figure 3.22. Week 11 – mFRR marginal prices; (a) Balancing Energy Up; (b) Balancing Energy Down



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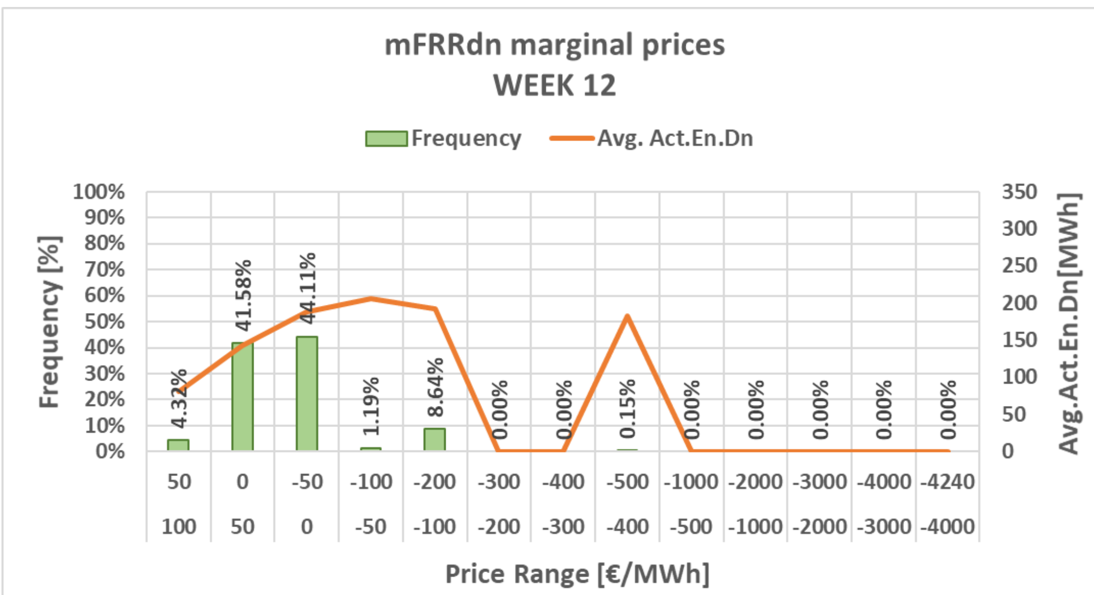
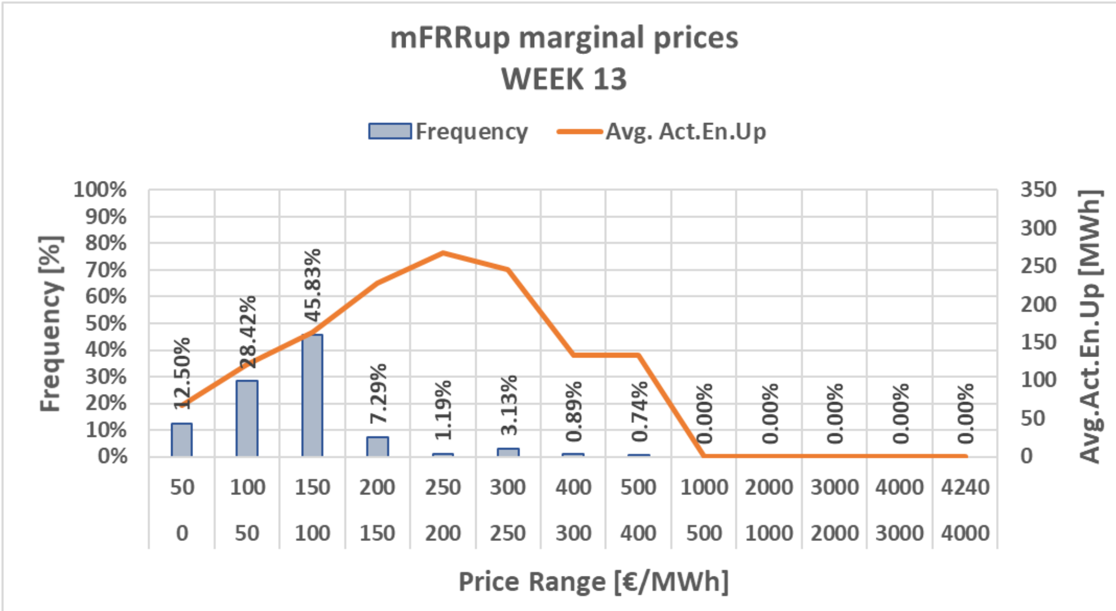
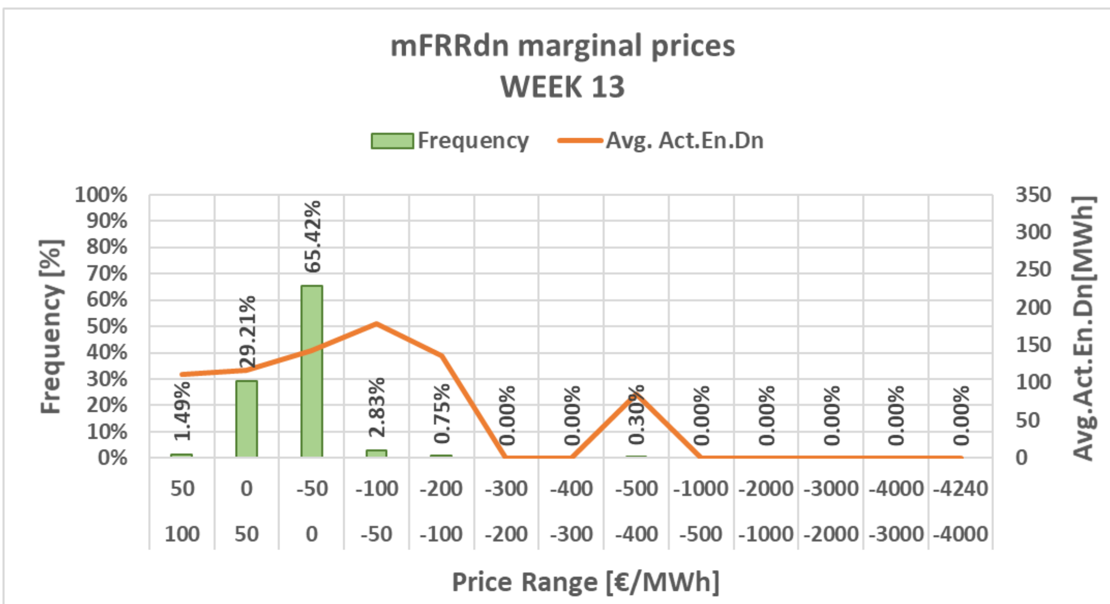


(b)

Figure 3.23. Week 12 – mFRR marginal prices; (a) Balancing Energy Up; (b) Balancing Energy Down



(a)



(b)

Figure 3.24. Week 13 – mFRR marginal prices; (a) Balancing Energy Up; (b) Balancing Energy Down

3.2 ISP Analysis

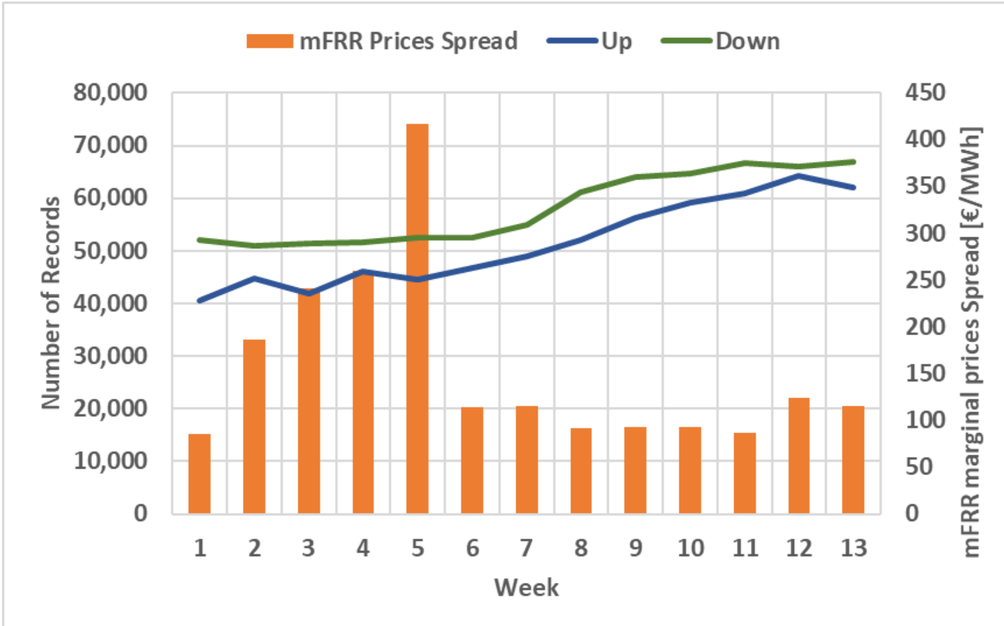
The present sub-chapter is separated into two sections. The first section copes with the ISP Energy offers, where the number of records of the offers per direction is presented in a weekly resolution and the correlation between ISP offers and the Balancing Energy Cost is investigated. Also, a statistical analysis is performed on the weekly ISP Energy offers accordingly to the statistical analysis of mFRR marginal prices as performed in the above section 3.1.2. In the second section of the present sub-chapter, an analysis on the ISP results is performed, considering the volumes of activated balancing energy and the awarded capacity reserves per type and technology of generation unit, as well as the energy clearing prices produced in the ISP executions. In the scope of the second section analysis, the correlation between the ISP results and the Imbalance Settlement Procedure results is also investigated.

3.2.1 ISP Energy Offers

The number of records is calculated according to equation (3.27). Although, the data file of the ISP offers as published in the official TSO's website [62], does not contain discreetly the information about the number of assets of BSPs' (noA) and the number of steps (noS) per offer, the total number of records in the weekly file include the corresponding components.

$$Count\_of\_records_{week}^{ISP\_Offered\_Prices} = doW * 48 * noA * noS \tag{3.27}$$

In Figures 3.25(a) & 3.25(b) the number of records for ISP Energy Offers is presented for upwards and downwards balancing energy. More specifically, in Figure 3.25(a) the correlation with the mFRR marginal prices spread is illustrated, while in Figure 3.25(b) the correlation with the Balancing Energy Cost is illustrated. As shown in the respective Figures, the increase in the number of ISP Energy Offers records follows a decrease in the mFRR Prices Spread and consequently in the final Balancing Energy Cost.



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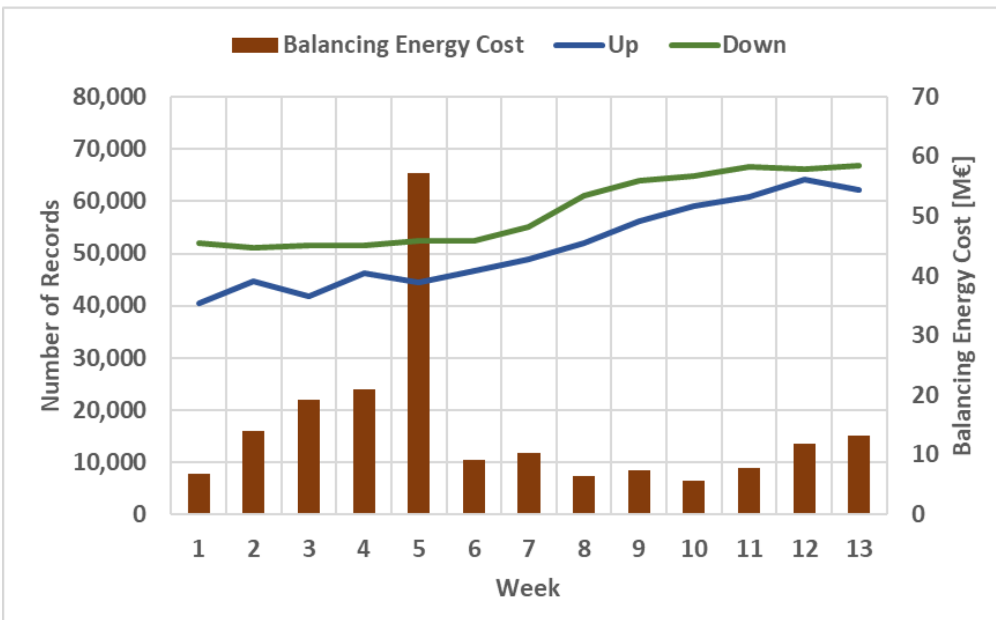
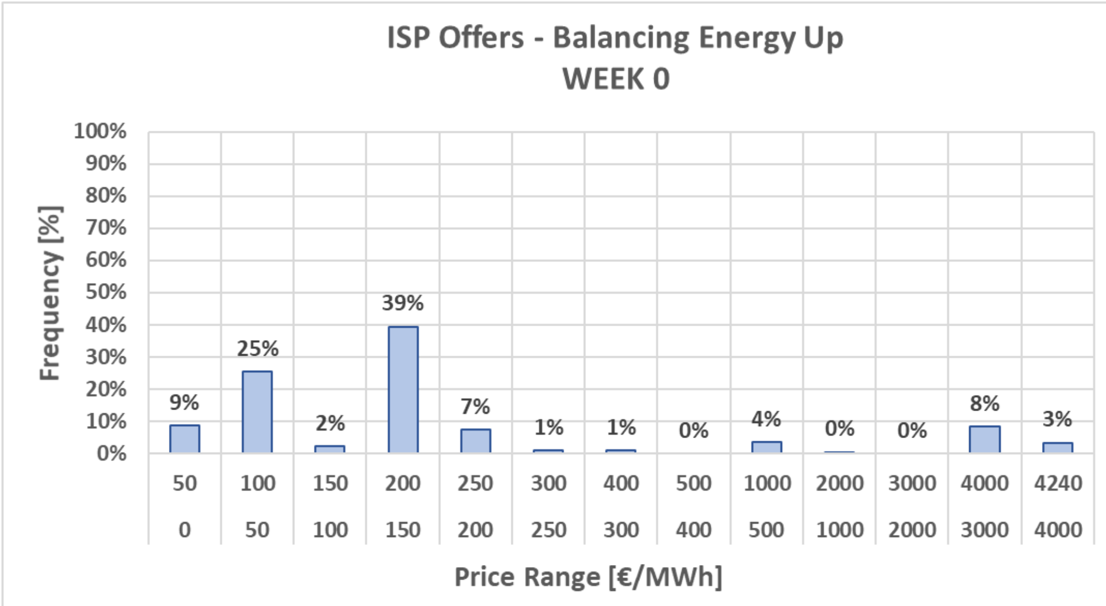
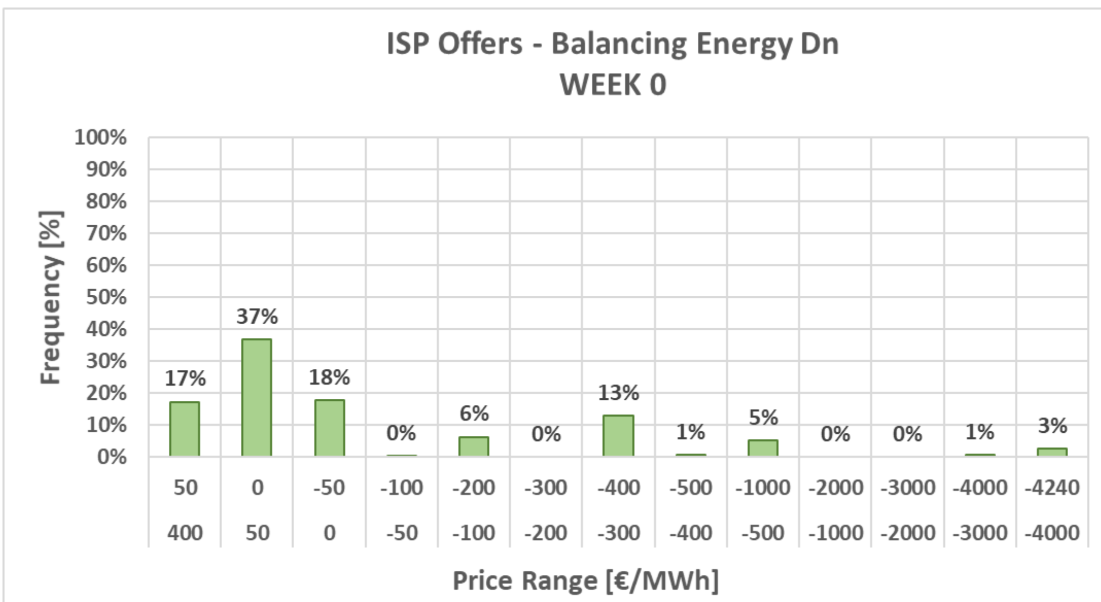


(b)

Figure 3.25. ISP Offers – Weekly Count of Records for Balancing Energy

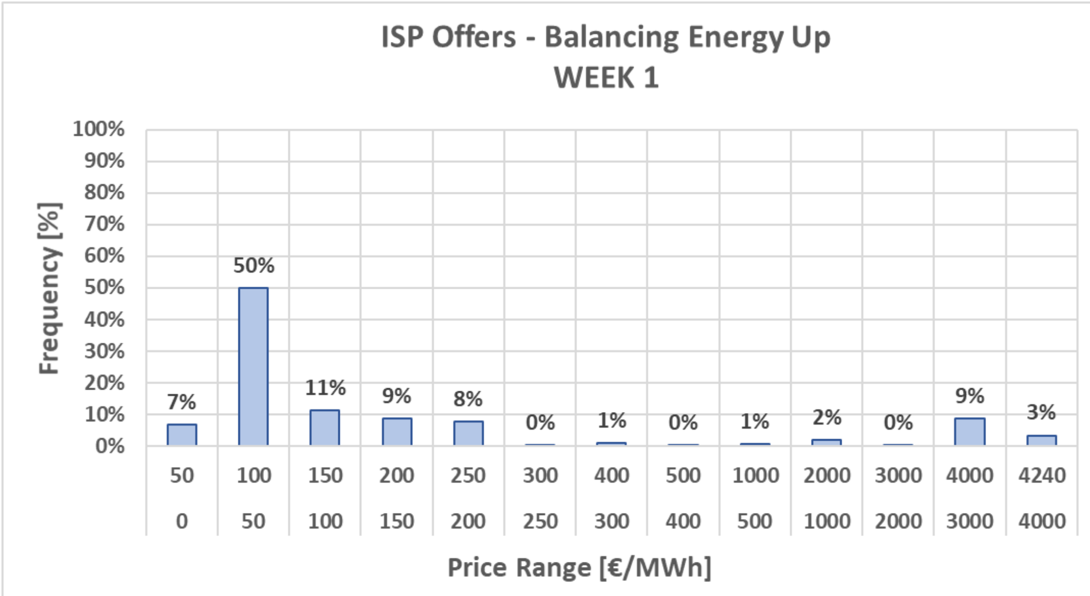


(a)

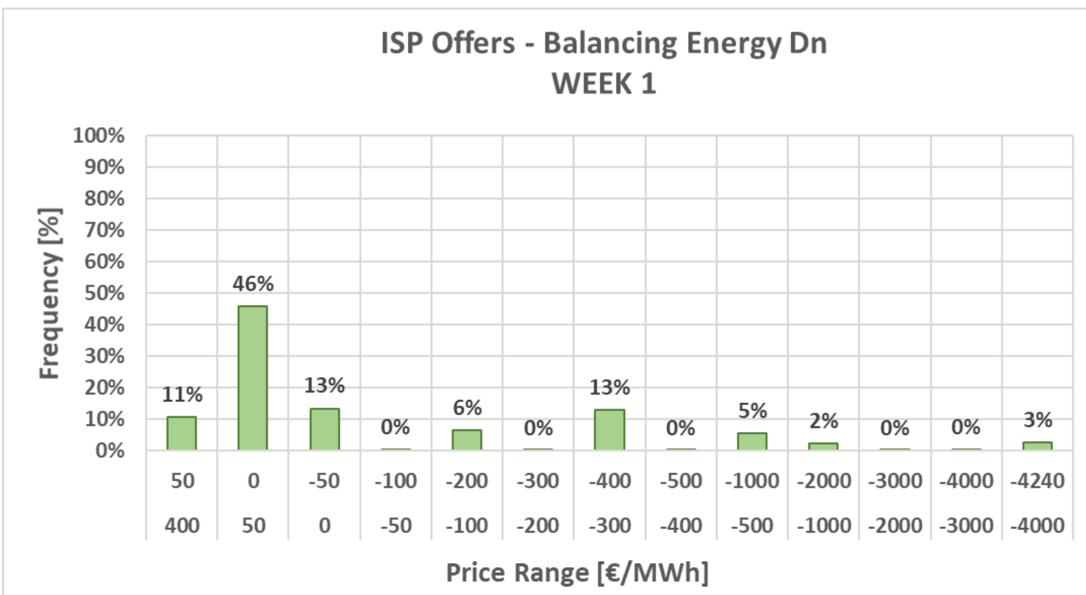


(b)

Figure 3.26. Week 0 – ISP Offers; (a) Balancing Energy Up; (b) Balancing Energy Down

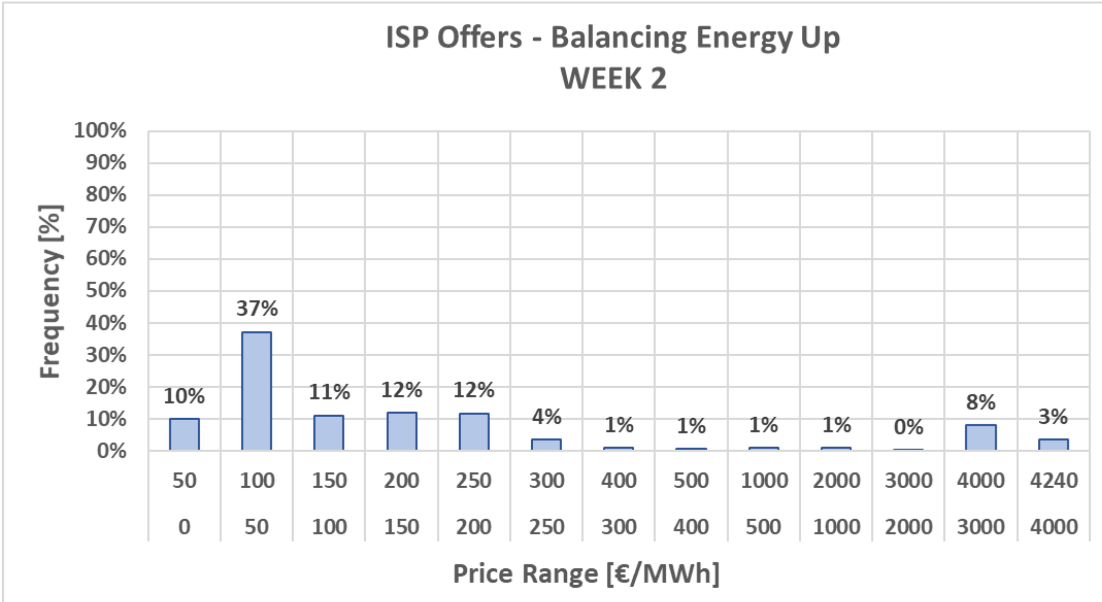


(a)

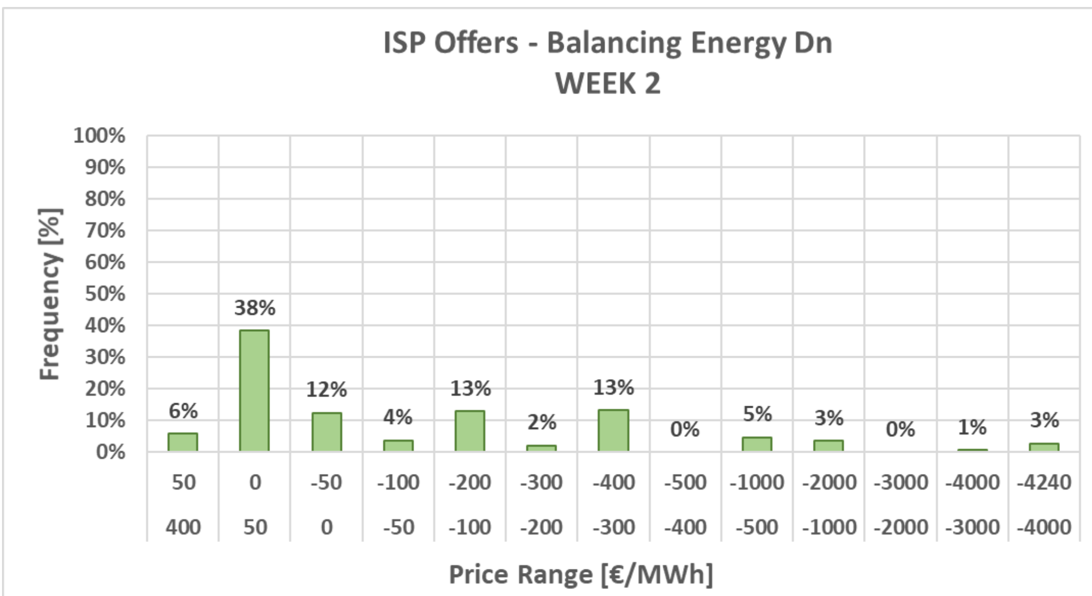


(b)

Figure 3.27. Week 1 – ISP Offers; (a) Balancing Energy Up; (b) Balancing Energy Down

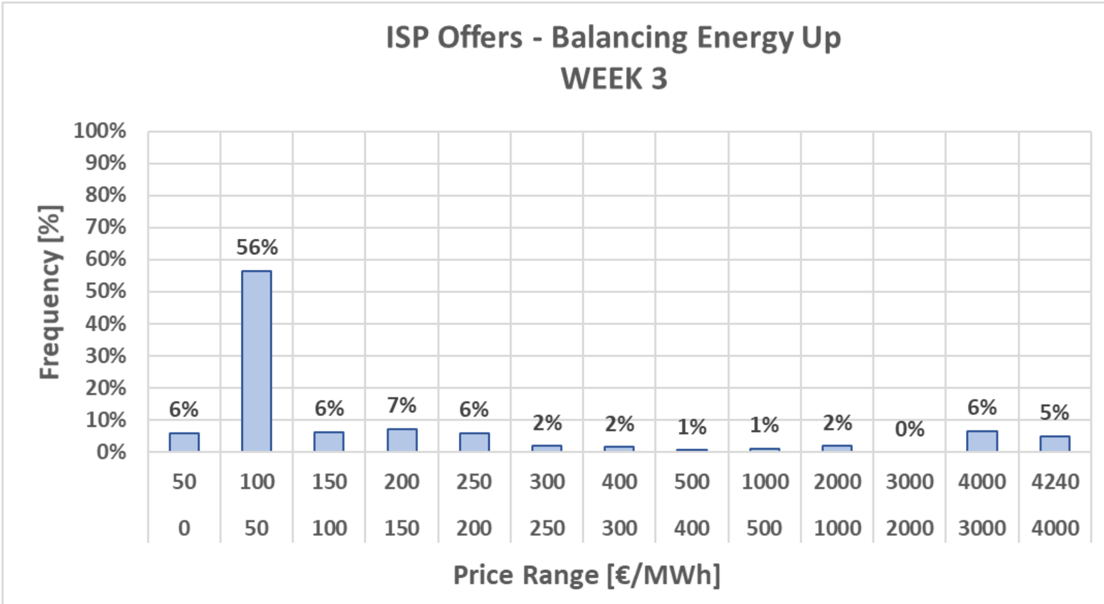


(a)

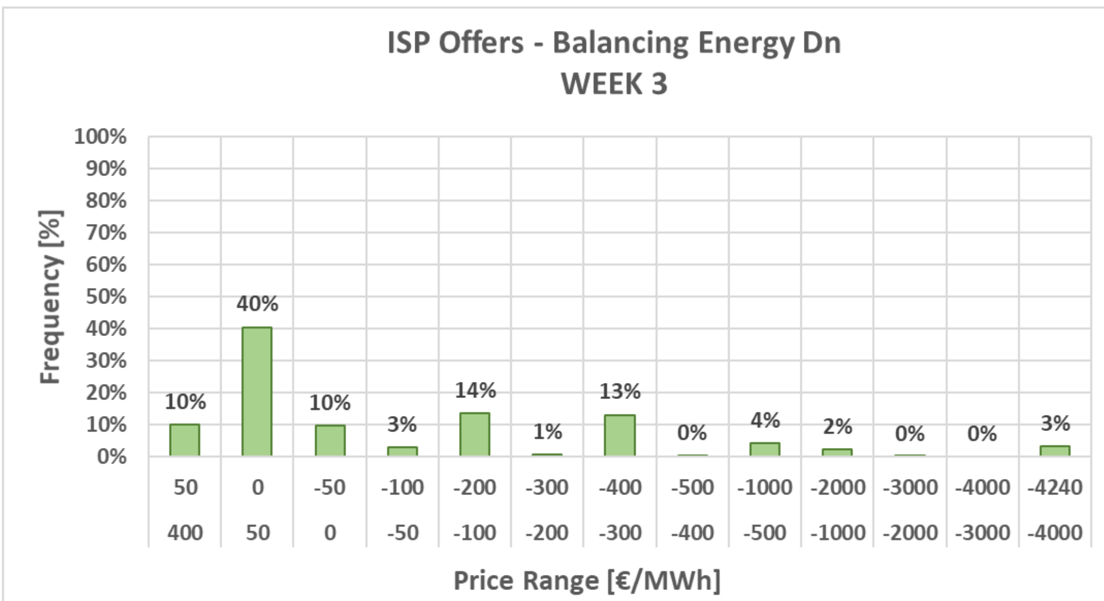


(b)

Figure 3.28. Week 2 – ISP Offers; (a) Balancing Energy Up; (b) Balancing Energy Down

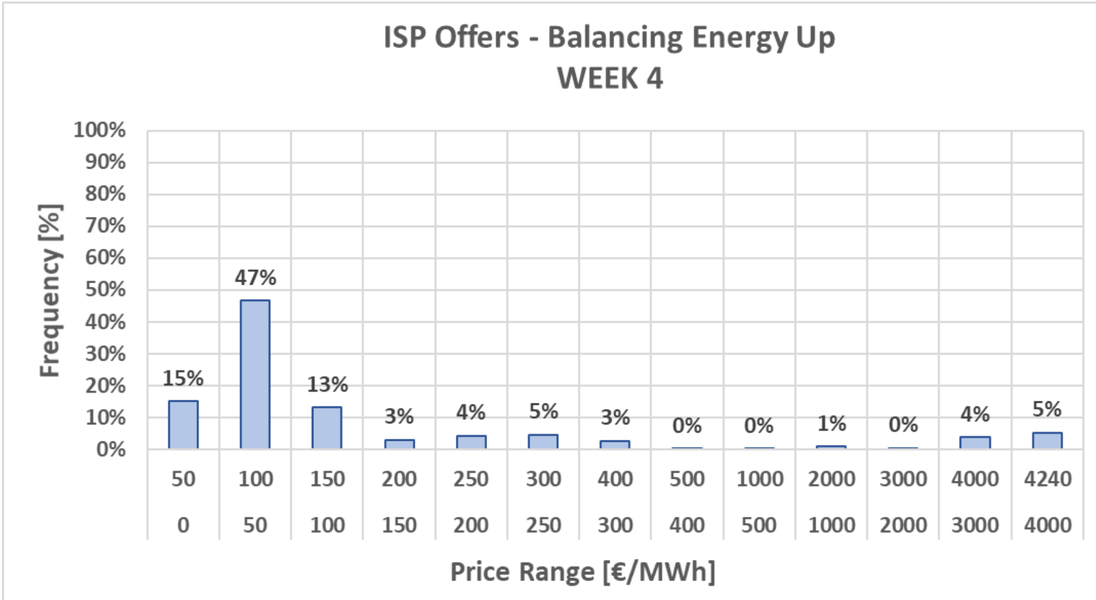


(a)



(b)

Figure 3.29. Week 3 – ISP Offers; (a) Balancing Energy Up; (b) Balancing Energy Down



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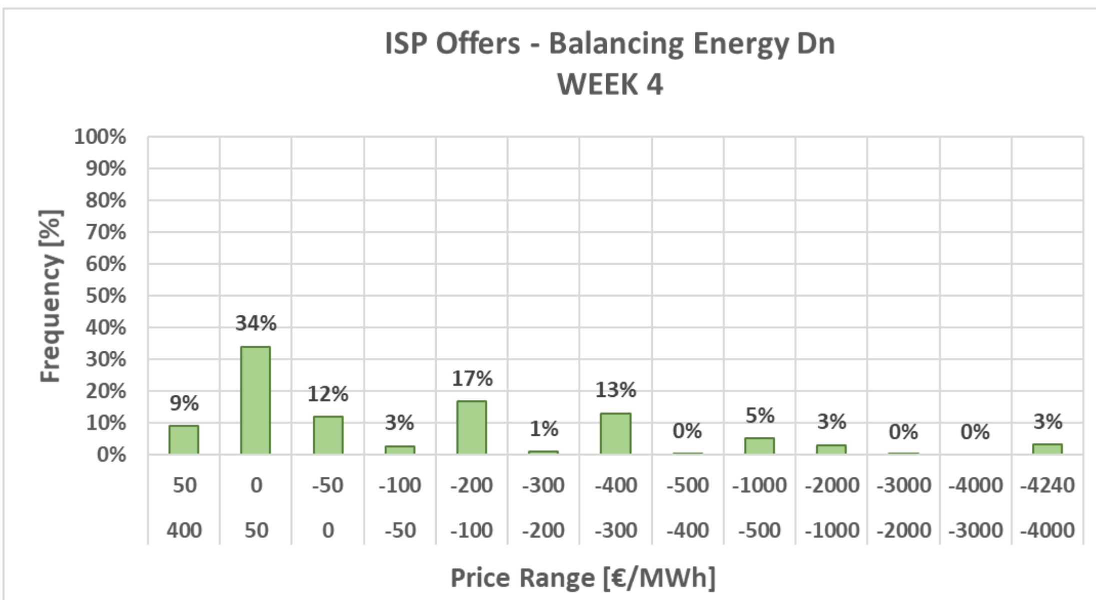
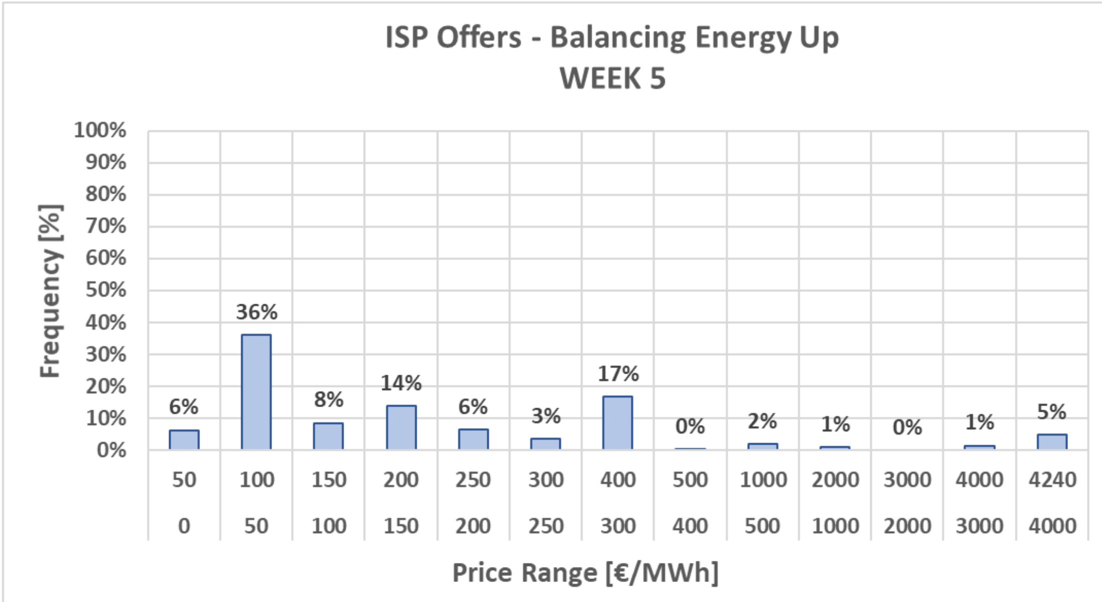
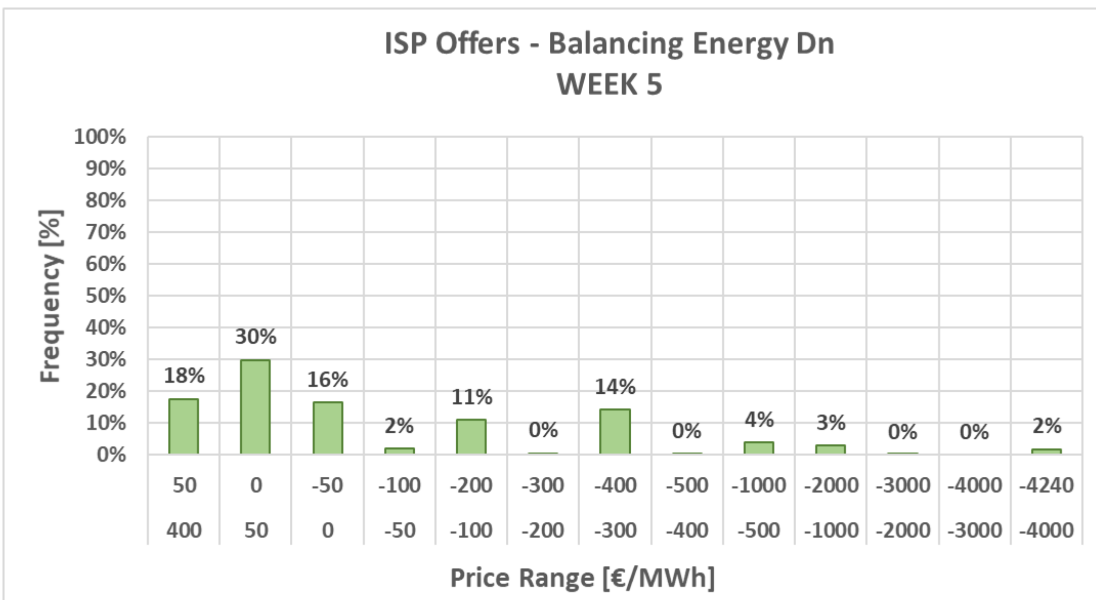


(b)

Figure 3.30. Week 4 – ISP Offers; (a) Balancing Energy Up; (b) Balancing Energy Down

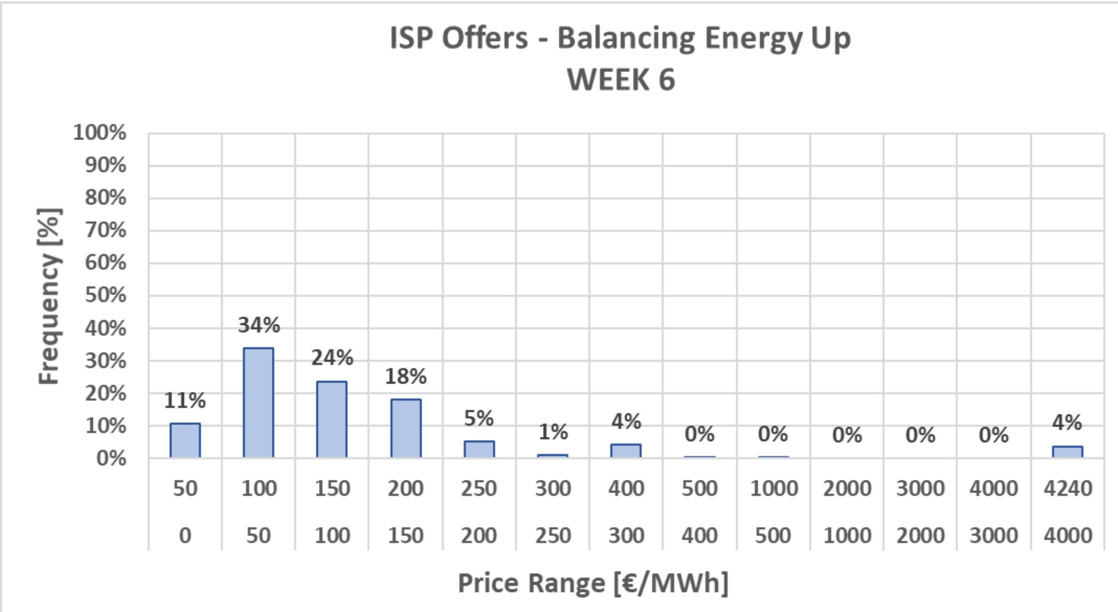


(a)

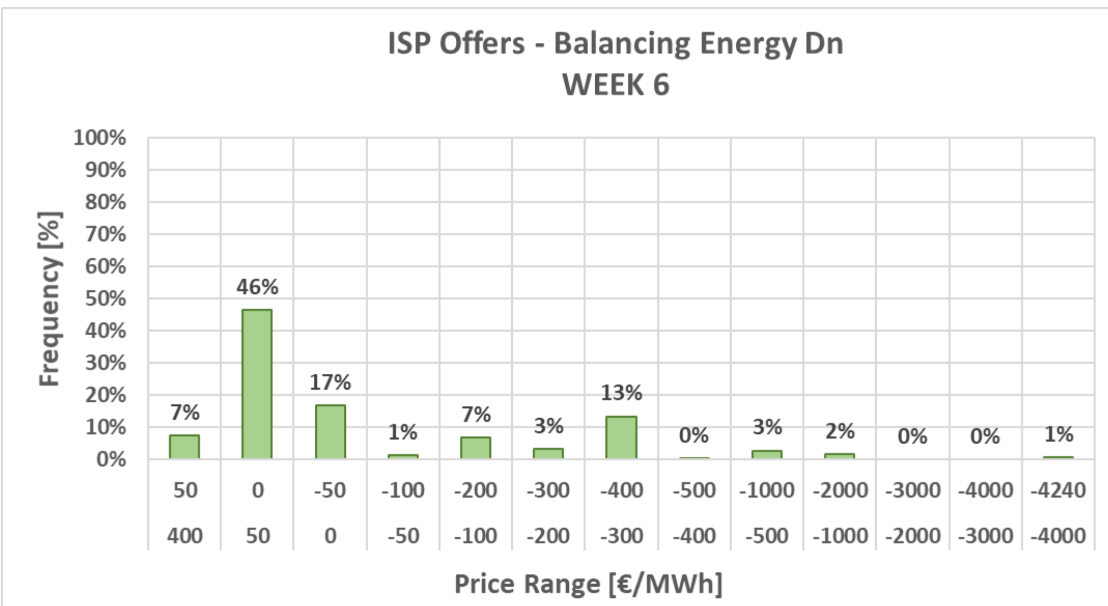


(b)

Figure 3.31. Week 5 – ISP Offers; (a) Balancing Energy Up; (b) Balancing Energy Down

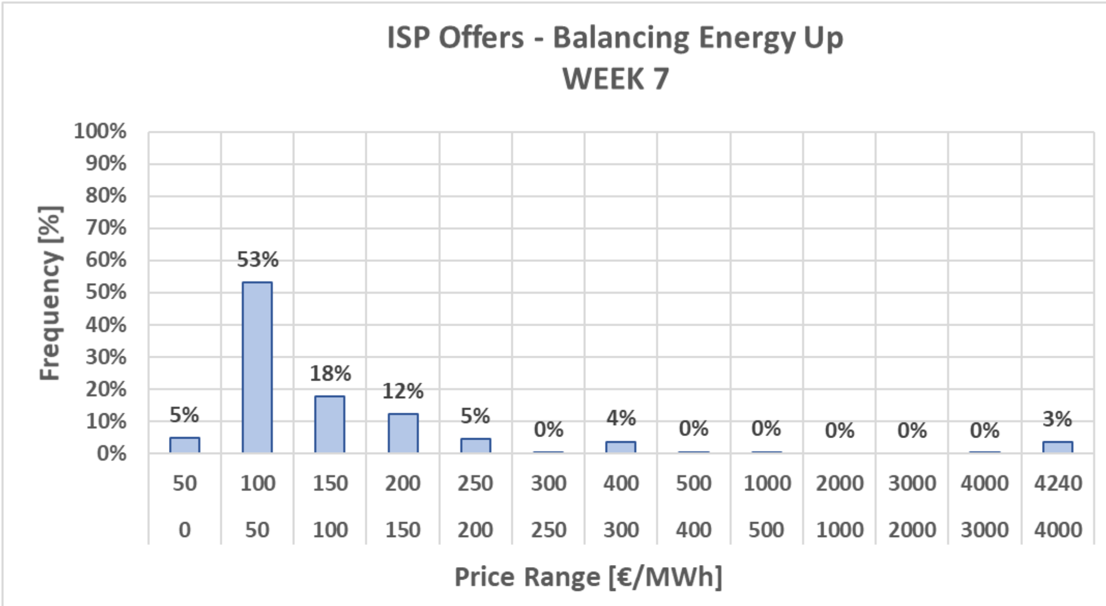


(a)

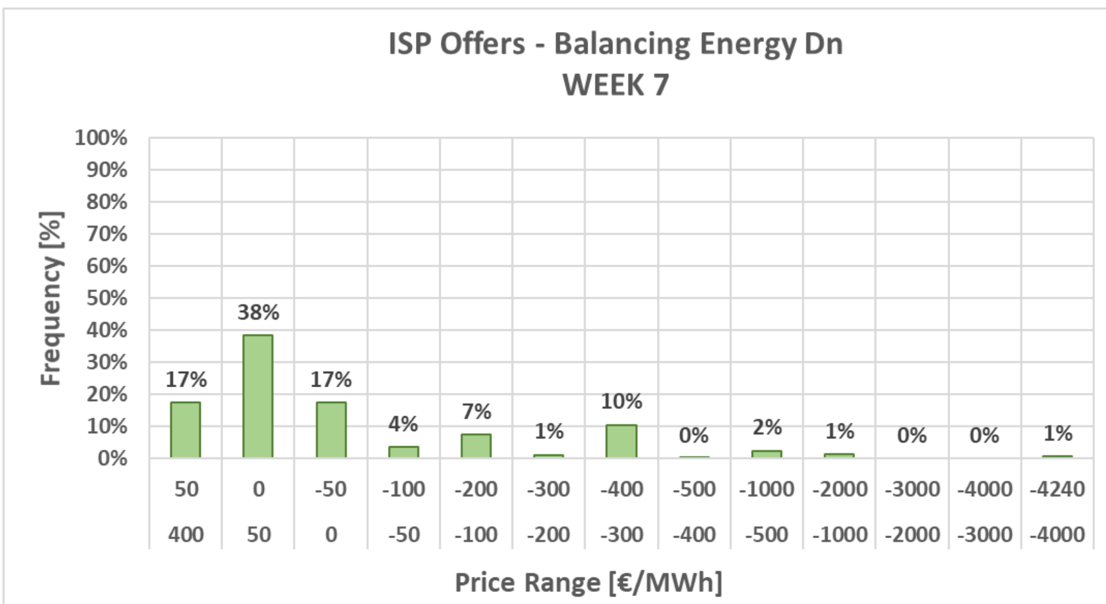


(b)

Figure 3.32. Week 6 – ISP Offers; (a) Balancing Energy Up; (b) Balancing Energy Down

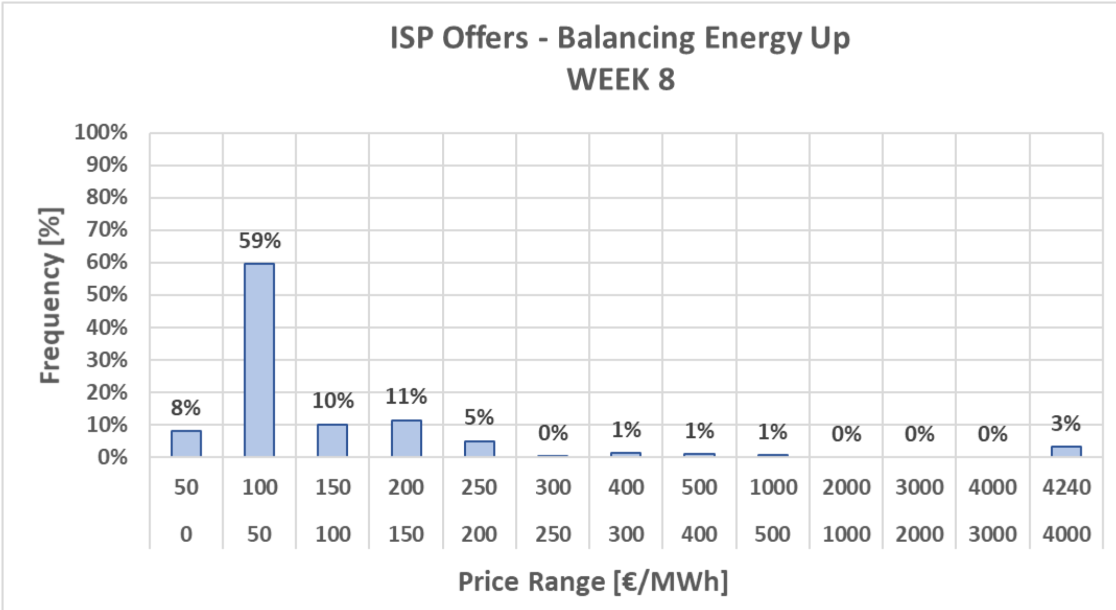


(a)

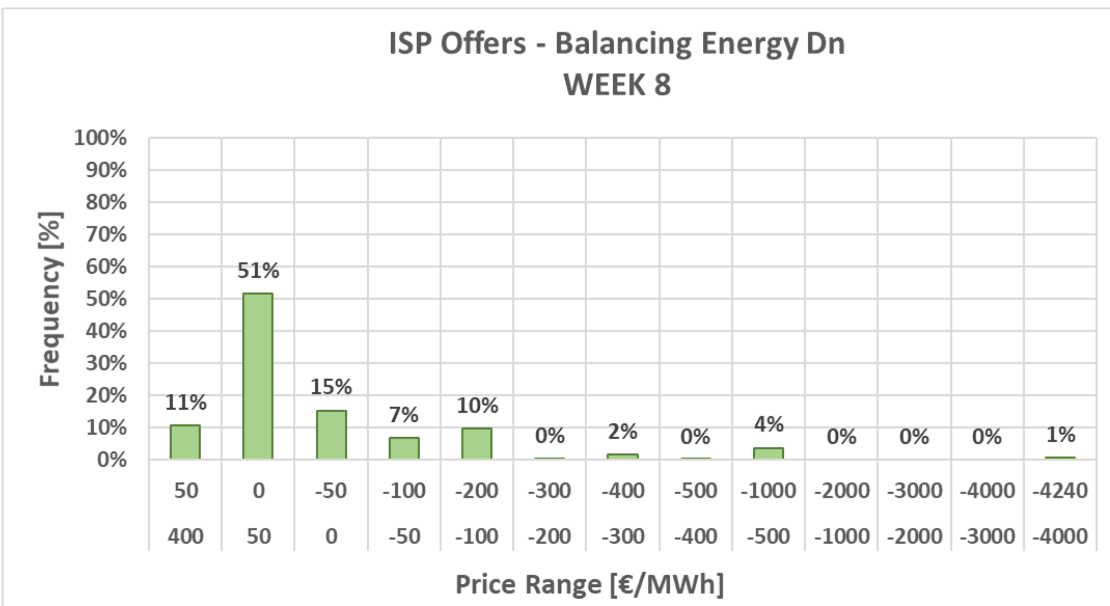


(b)

Figure 3.33. Week 7 – ISP Offers; (a) Balancing Energy Up; (b) Balancing Energy Down

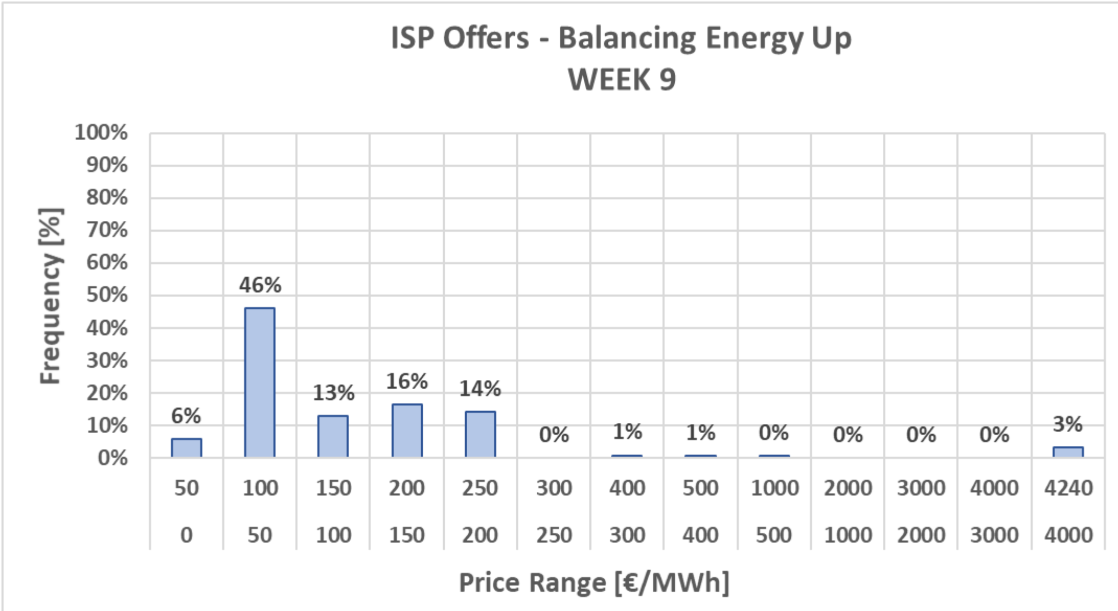


(a)

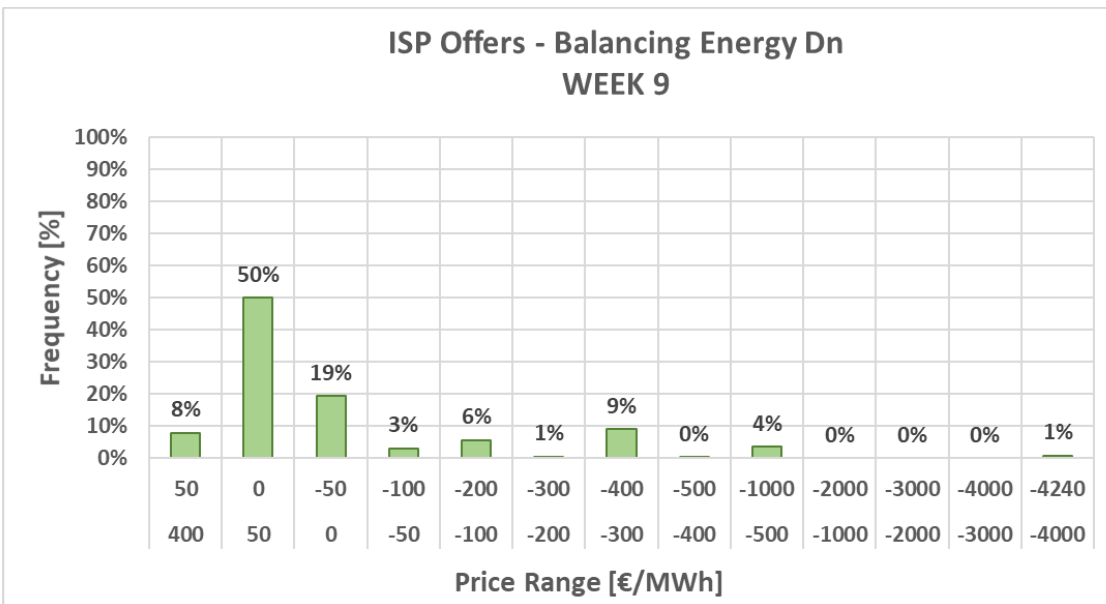


(b)

Figure 3.34. Week 8 – ISP Offers; (a) Balancing Energy Up; (b) Balancing Energy Down

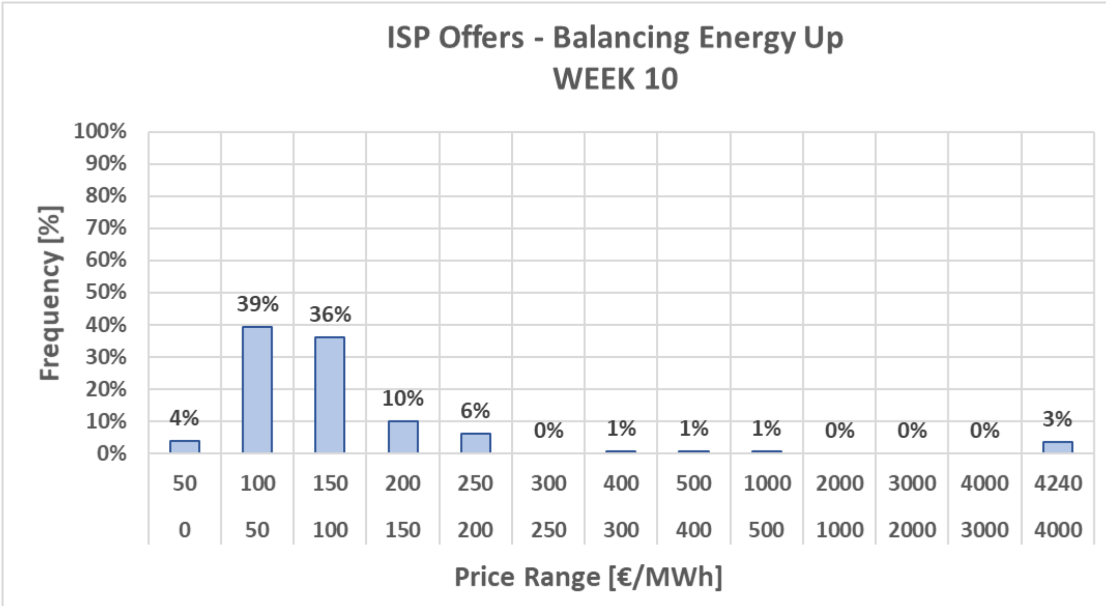


(a)

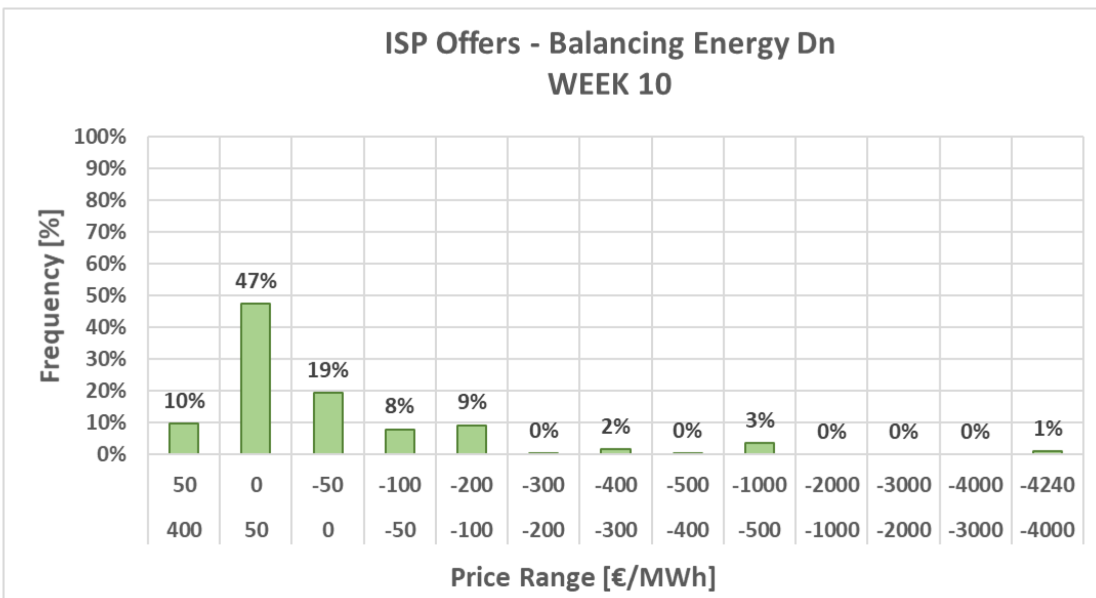


(b)

Figure 3.35. Week 9 – ISP Offers; (a) Balancing Energy Up; (b) Balancing Energy Down

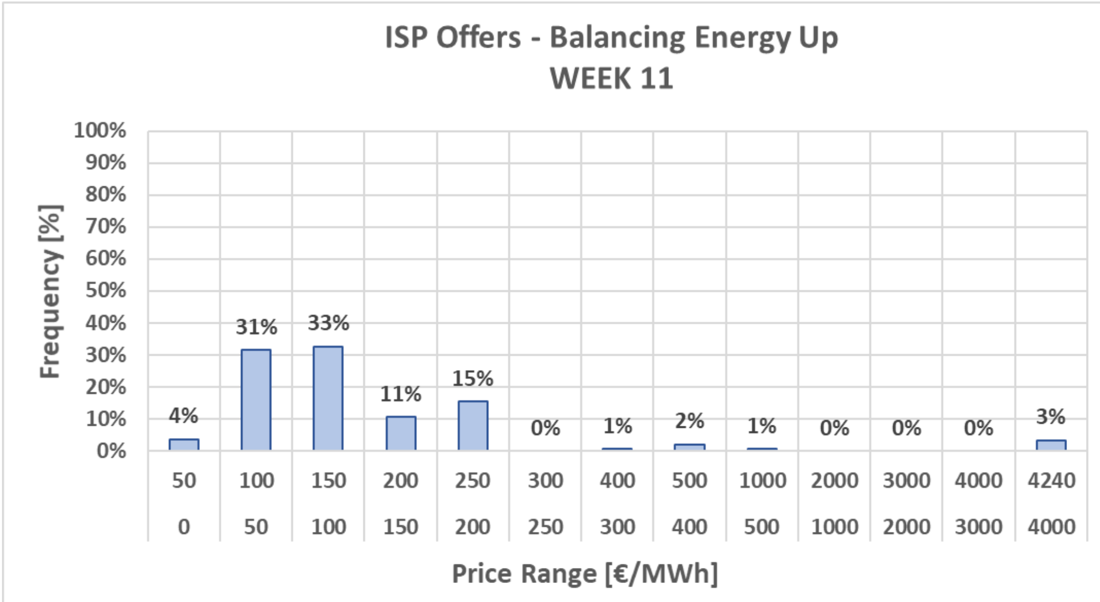


(a)

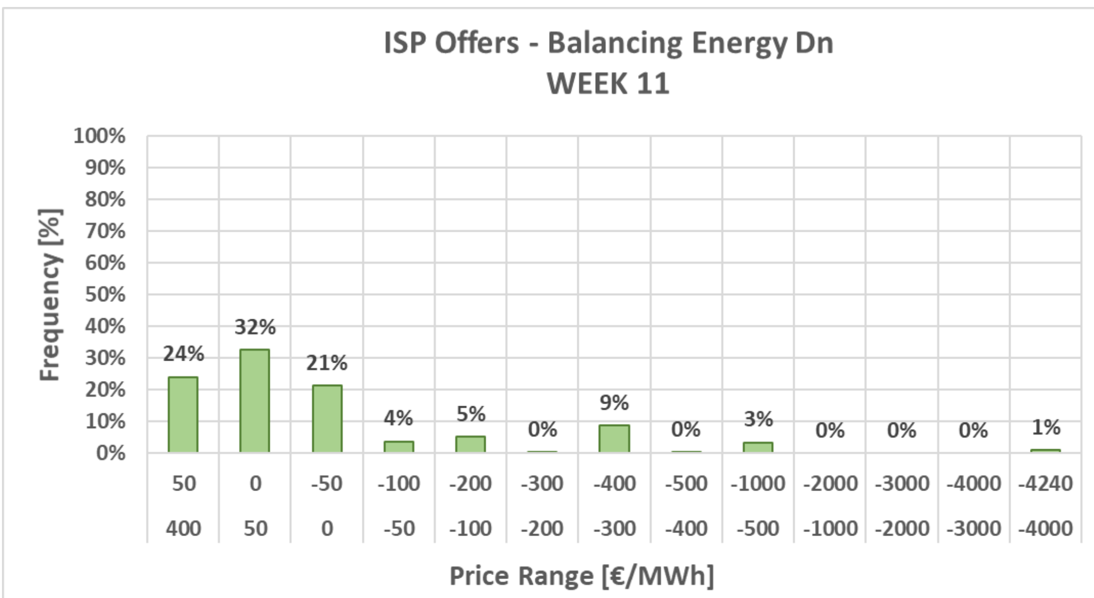


(b)

Figure 3.36. Week 10 – ISP Offers; (a) Balancing Energy Up; (b) Balancing Energy Down

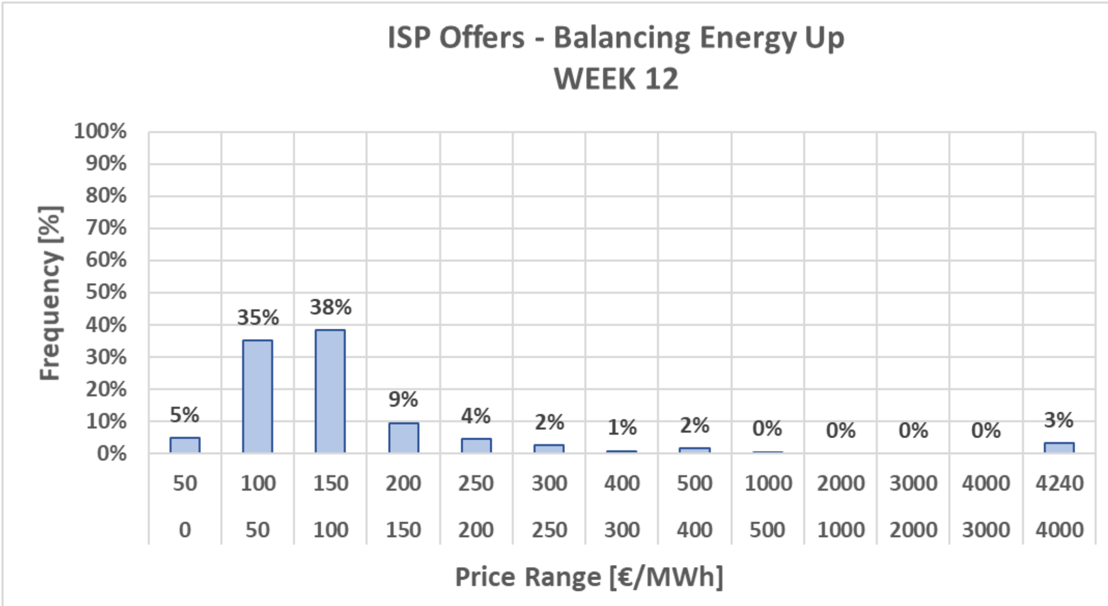


(a)

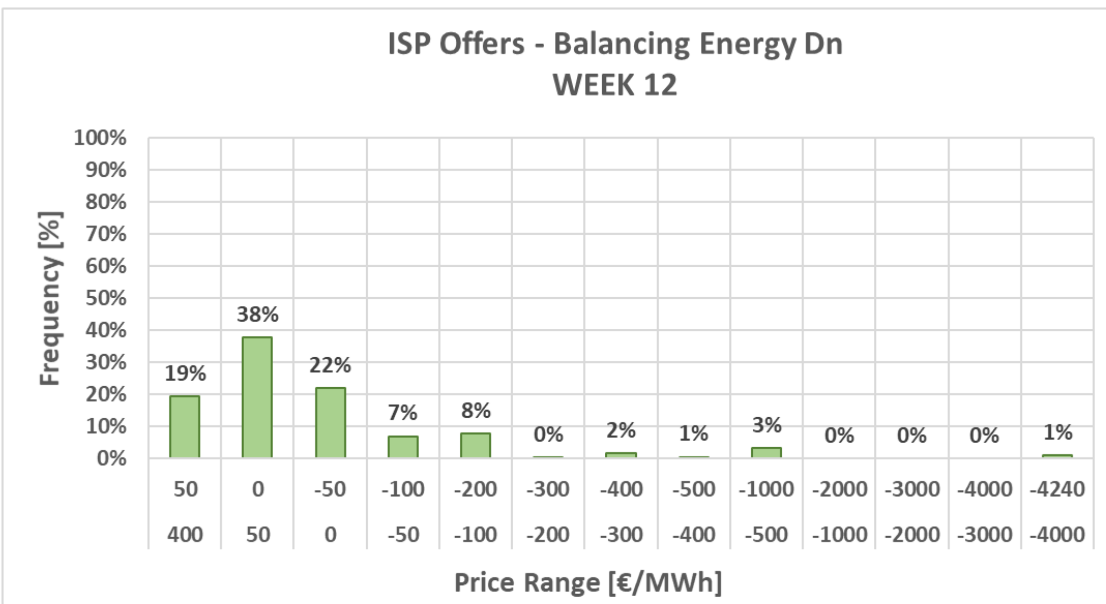


(b)

Figure 3.37. Week 11 – ISP Offers; (a) Balancing Energy Up; (b) Balancing Energy Down

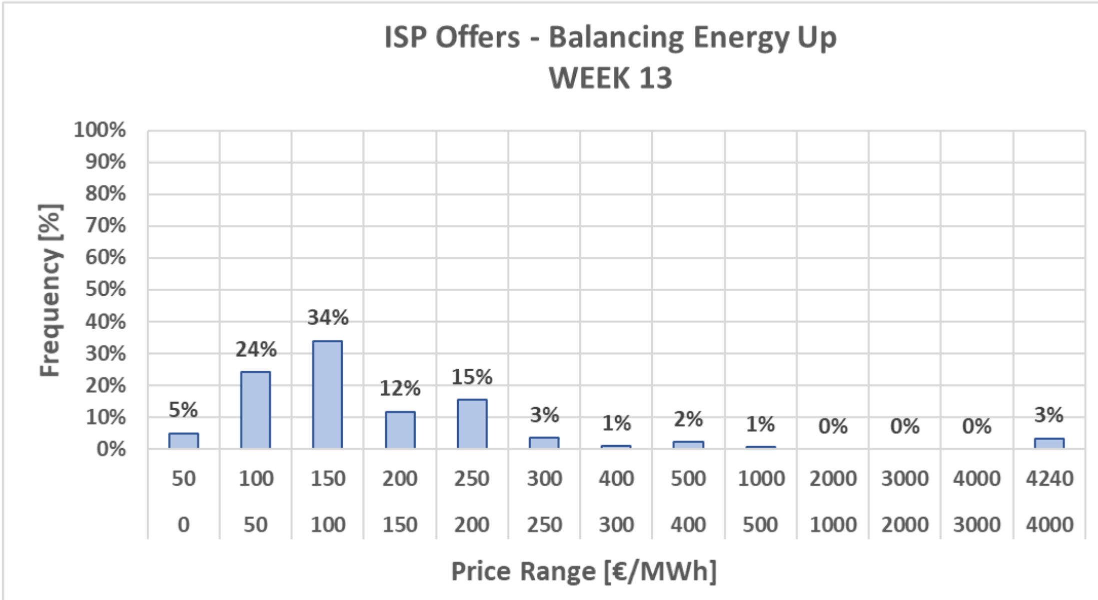


(a)

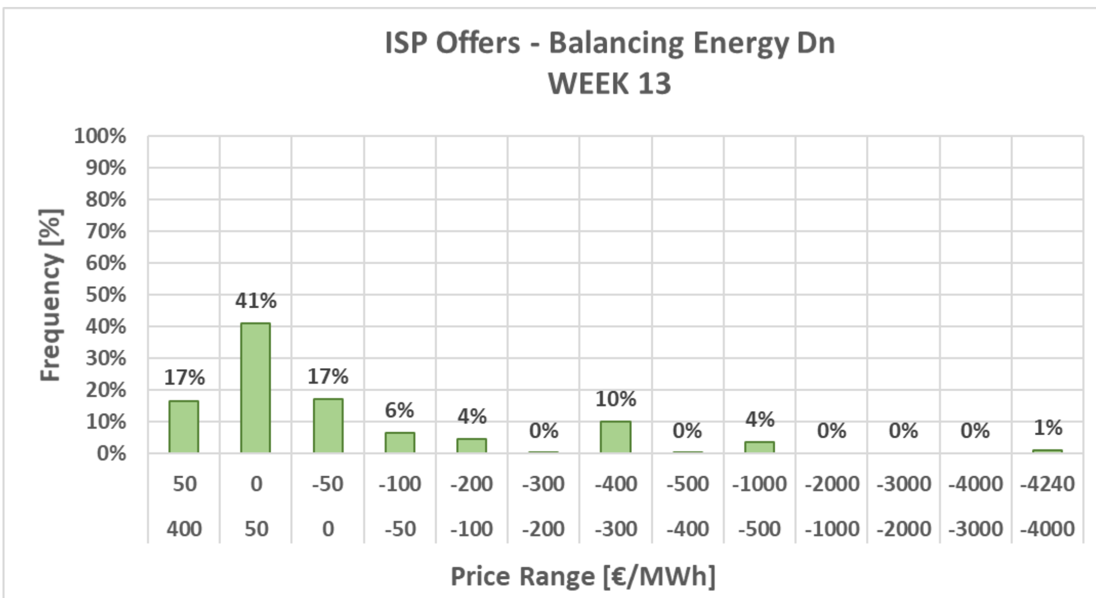


(b)

Figure 3.38. Week 12 – ISP Offers; (a) Balancing Energy Up; (b) Balancing Energy Down



(a)



(b)

Figure 3.39. Week 13 – ISP Offers; (a) Balancing Energy Up; (b) Balancing Energy Down

3.2.2 ISP Results

In the present section, the analysis is performed on the data as resulted from the ISP executions. The most valid and most recent ISP results are considered for each ISP period, as described in the Balancing Market Code [64], in order to formulate the respective binding schedules of the production units for each day. More specifically, for the binding schedule to be defined, for each day, the first 24 ISP periods are considered from the results of ISP2 and the last 24 ISP periods from the results of ISP3, as well as any possible Ad-hoc executions of the ISP according to the publication time of the Ad-hoc ISP results.

3.2.2.1 Activated Energy

In Figure 3.40 the total activated energy considering both directions, is presented as resulted from the ISP executions, in the same graph with the resulted total volumes of activated energy that settled in the Imbalance Settlement Procedure. As it can be seen from the respective Figure, the resulted ISP activated energy volumes are always lower than the ones that are awarded through the RTBM and ultimately settled in the Imbalance Settlement procedure. However, there is a strong correlation as the ISP activated energy volumes follow the trend of the settled volumes.

The highest volumes of ISP activated energy are resulted in week 5, the same as for the settled volumes, at 168,793MWh for ISP volumes and 209,848MWh for settled ones. Excluding from the present analysis the week 0, as it considers only one day, in week 3 the ISP weekly volumes are minimum at 78,788MWh and the settled volumes for week 3 are 148,604MWh. The minimum of settled volumes is resulted in week 10 at 116,223MWh with the respective ISP volumes being at 80,703MWh. As the ISP volumes of week 3 and week 10 do not have essential difference, the correlation between the ISP and the settled volumes remains.

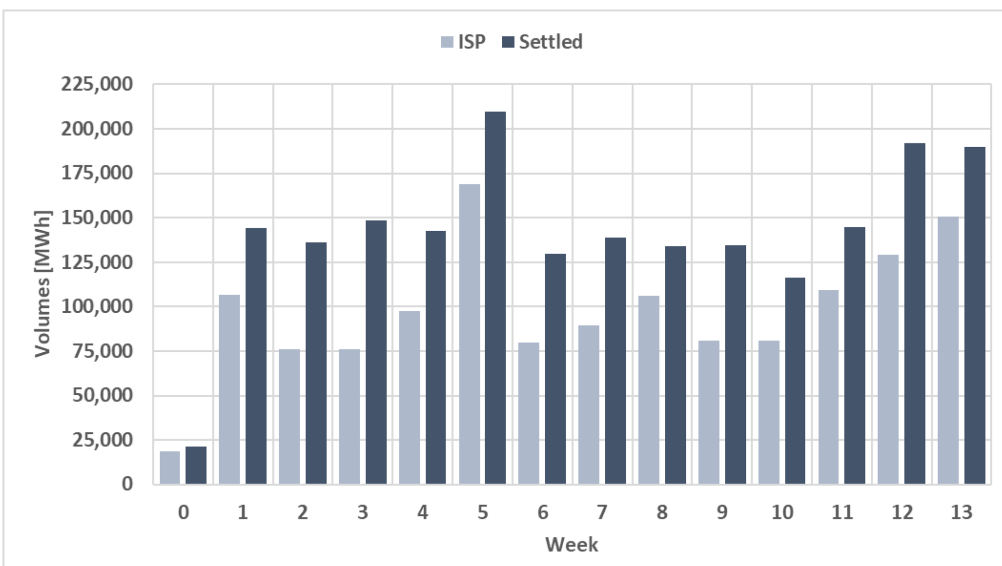
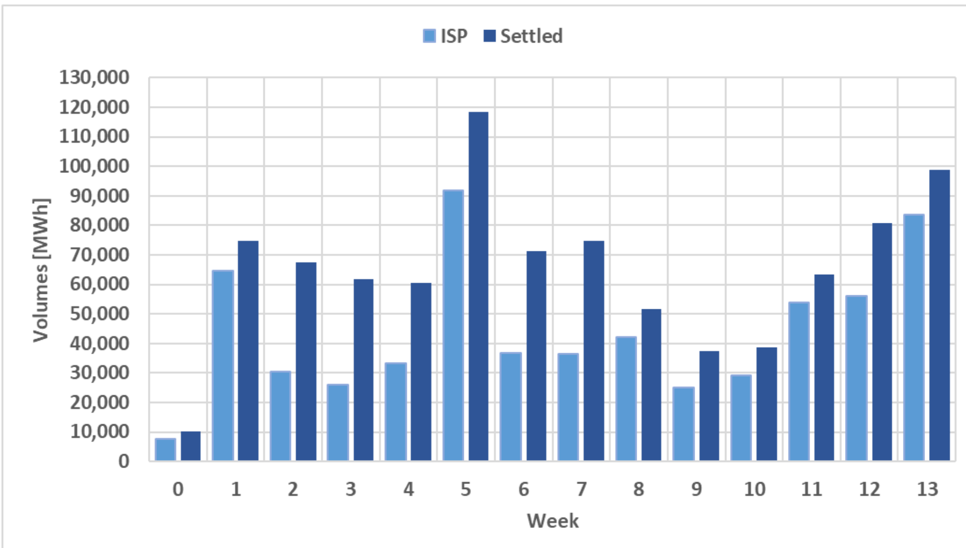
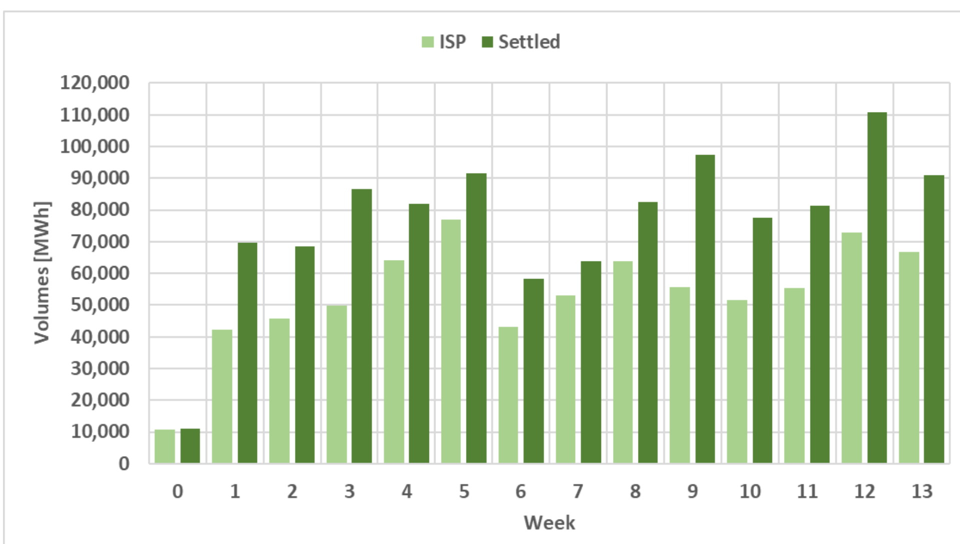


Figure 3.40. Correlation of weekly Total activated balancing energy

The analysis of the weekly activated volumes from the ISP results and the Imbalance Settlement Procedure, separately for upwards and downwards direction, is presented in Figures 3.41(a) and 3.41(b), respectively. As shown in Figure 3.42(a) the difference between the ISP volumes and the settled ones is larger in weeks 2, 3, 4, 6 and 7 and for the other weeks the respective differences are smaller. The correlation remains for the respective direction and the maximum of ISP volumes is in week 5 as in the case of the settled volumes. Regarding the downwards volumes as shown in Figure 3.42(b), there is also an obvious correlation, however the maximum of ISP volumes is resulted in week 5, whereas the maximum of settled downwards volumes is resulted in week 11.



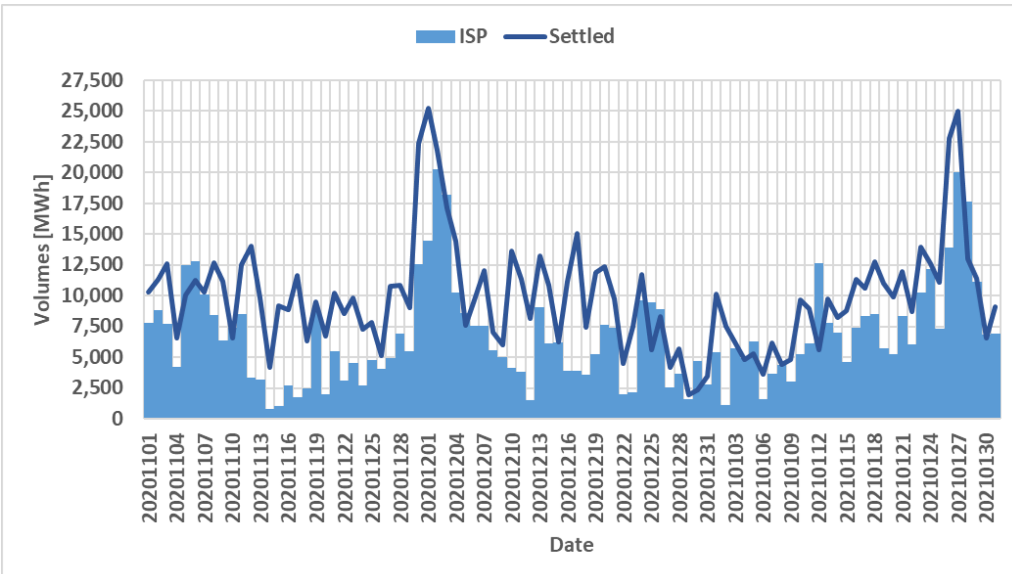
(a)



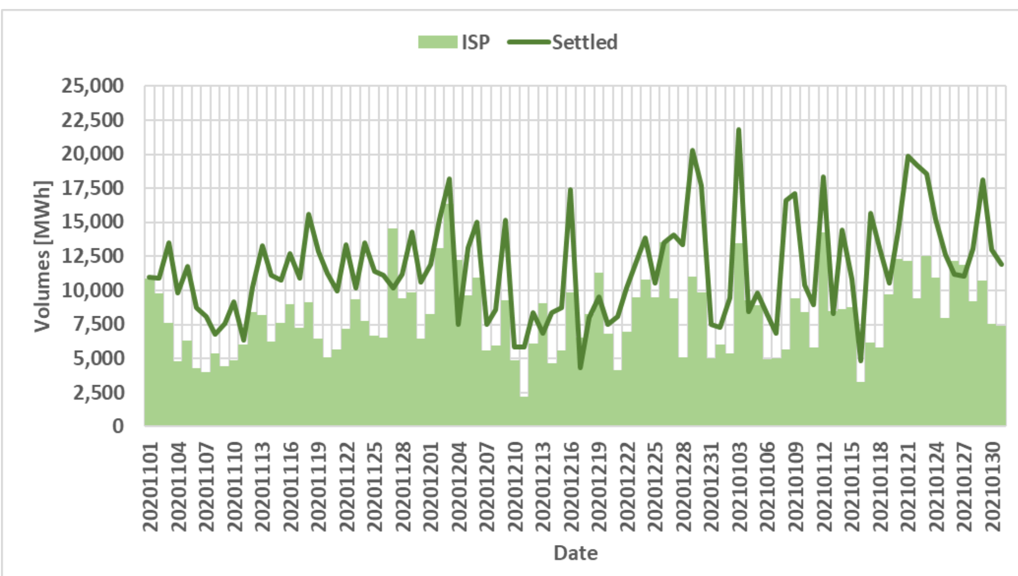
(b)

Figure 3.41. Correlation of weekly activated balancing energy; (a) upwards; (b) downwards

The analysis of the daily activated volumes from the ISP results and the Imbalance Settlement Procedure [62], separately for upwards and downwards direction, is presented in Figures 3.42(a) and 3.42(b), respectively. As shown in the respective Figures there is an obvious correlation between the ISP daily volumes and the respective settled ones, as the spikes in the resulted ISP volumes are followed by respective spikes of the settled volumes. The highest ISP volumes for the upwards activated energy were resulted on 02.12.2020 (20,227MWh), on 03.12.2020 (18,232MWh) and on 27.01.2020 (20,049MWh). The highest ISP volumes for the downwards activated energy were resulted on 27.11.2020 (14,568MWh), on 03.12.2020 (16,341MWh) and on 12.01.2020 (14,284MWh).



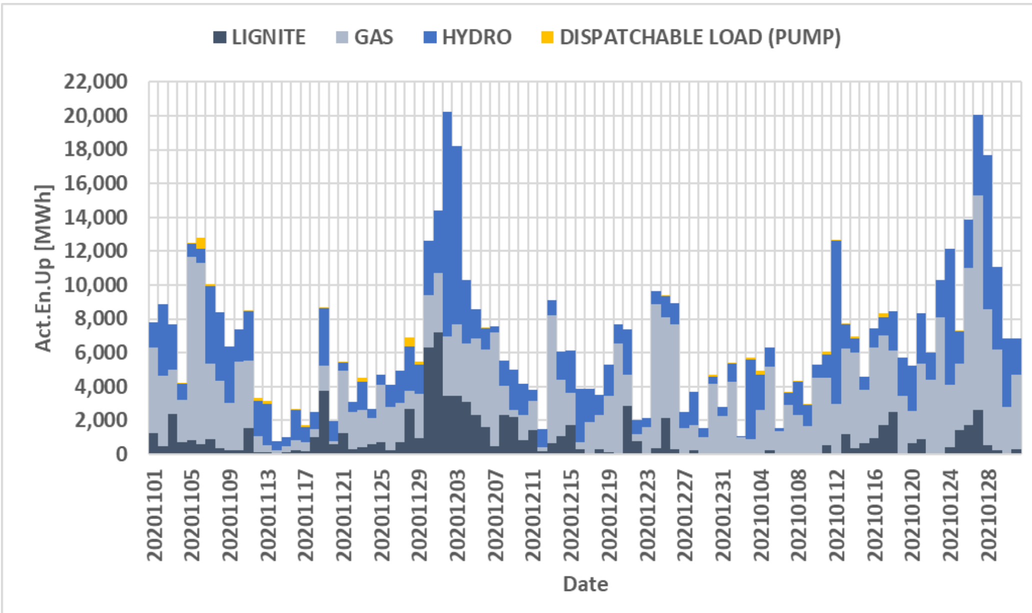
(a)



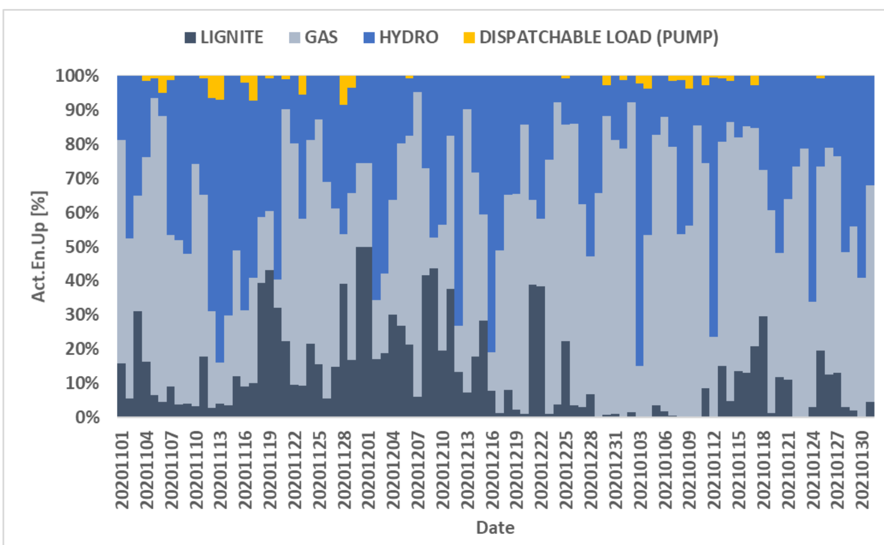
(b)

Figure 3.42 Correlation of daily activated balancing energy; (a) upwards; (b) downwards

A further analysis of the ISP volumes for the upwards balancing activated energy is illustrated in Figures 3.43(a) and 3.43(b), where the awarded volumes are presented per technology and respective shares. The eligible entities for the awarded balancing activated energy volumes are the Lignite, Gas and Hydro generation as well as, the pumping which is considered as dispatchable load. The highest shares of lignite are awarded on 30.11.2020 (6,294MWh – 50%) and 01.12.2020 (7,194MWh – 50%). The highest shares of natural gas are awarded on 05.11.2020 (10,869MWh – 87%), 06.11.2020 (10,712MWh – 84%) and 27.01.2021 (12,695MWh – 63%). The highest shares of Hydro are awarded on 02.12.2020 (13,281MWh – 66%) and 03.12.2020 (10,560MWh – 58%). The pumping is minimal compared to the other types.



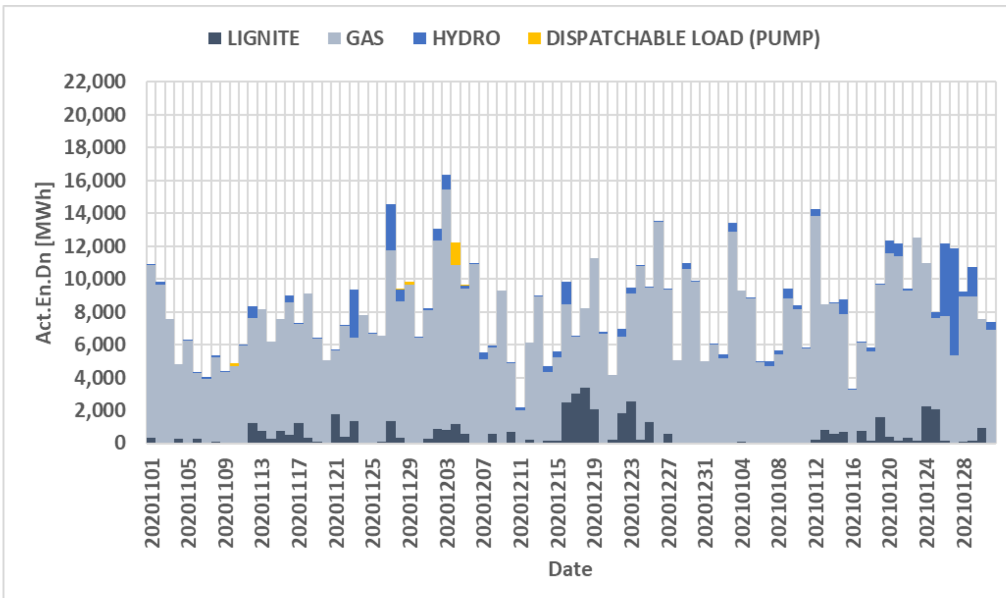
(a)



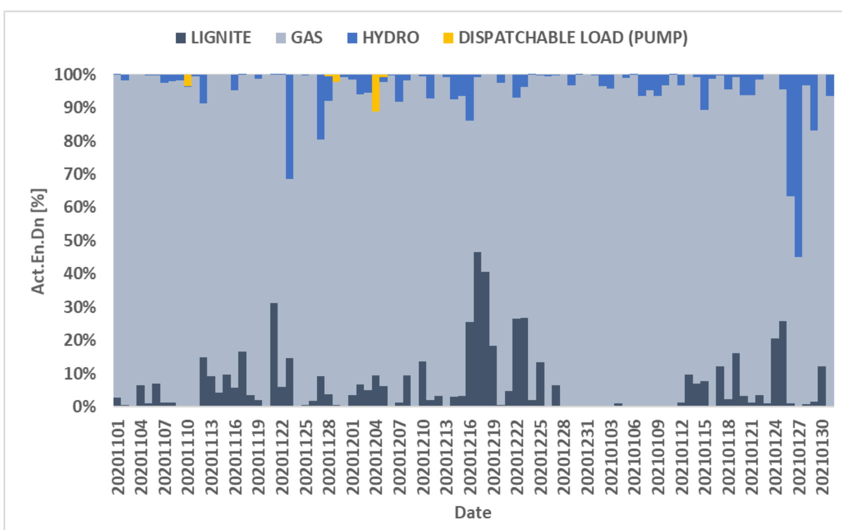
(b)

Figure 3.43. ISP Upwards Activated Energy (a) activated volumes; (b) share % per technology

A further analysis of the ISP volumes for the downwards balancing activated energy is illustrated in Figures 3.44(a) and 3.44(b), where the awarded volumes are presented per technology and respective shares. The eligible entities for the awarded balancing activated energy volumes are the Lignite, Gas and Hydro generation as well as, the pumping which is considered as dispatchable load. The highest shares of lignite are awarded on 17.12.2020 (3,030MWh – 47%) and on 18.12.2020 (3,360MWh – 41%). The highest shares of natural gas are awarded on 03.12.2020 (14,602MWh – 89%), 26.12.2020 (13,451MWh – 99%), 03.01.2021 (12,356MWh – 99%) and 23.01.2021 (12,356MWh – 99%). The highest shares of hydro are awarded on 26.01.2021 (4,447MWh – 37%) and 27.01.2021 (6,511,560MWh – 55%). The pumping is minimal compared to the other types.



(a)



(b)

Figure 3.44. ISP Downwards Activated Energy (a) activated volumes; (b) share % per technology

3.2.2.2 Capacity Reserves (FCR, aFRR, mFRR)

In the present section the Balancing Capacity reserves are analyzed based on the ISP results. In Figure 3.45 is shown the development of the total capacity reserves requirements as defined from the TSO in a daily resolution [62]. As shown in the respective graph, the capacity needs of the system are declining, with the highest being on 06.11.2020 (40,875MWh) and the lowest were defined on 27.12.2020 (25,177MWh). It is noted that in the scope of the present section, the capacity reserves are presented in MWh.

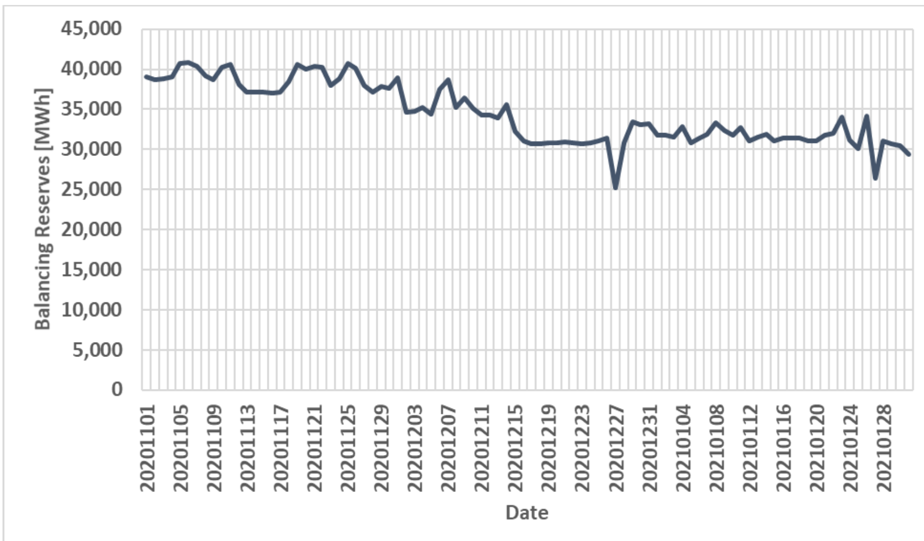
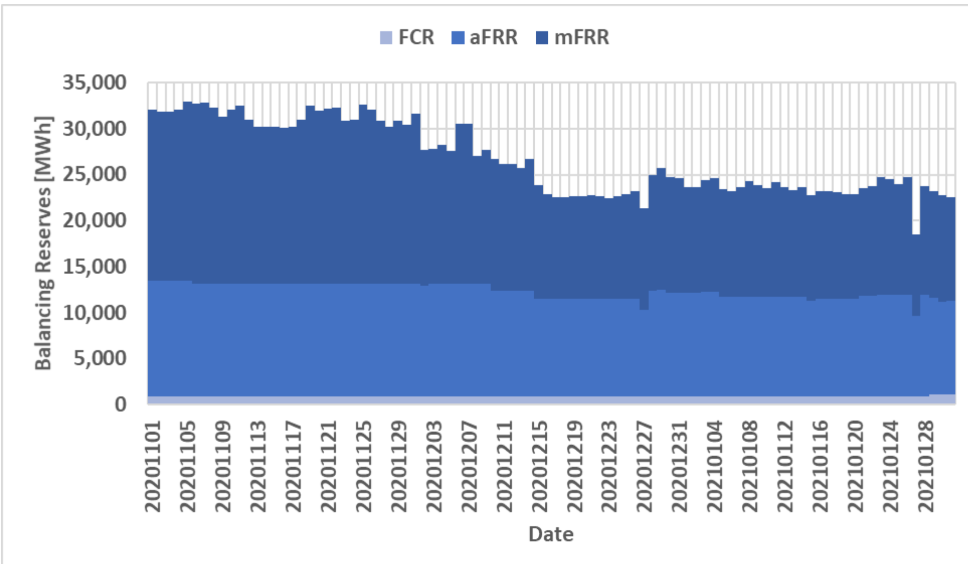


Figure 3.45. Total Capacity Reserves

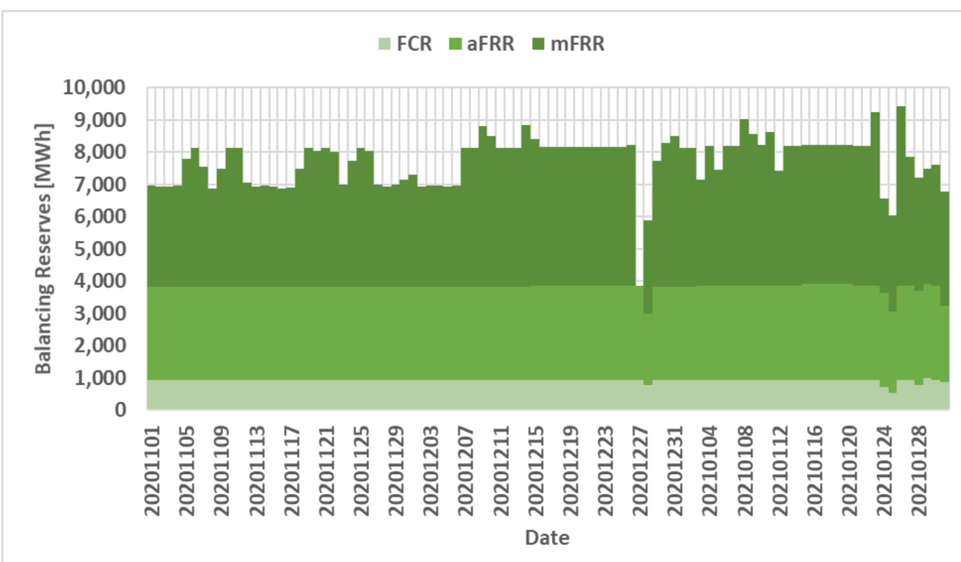
The assets that are eligible for the procurement of Balancing Capacity differ [62], according to the type of reserve product (i.e., FCR, aFRR, mFRR). In Figures 3.47(a) and 3.47(b) the total awarded capacity reserves are illustrated per reserve type, for upwards and downwards direction, respectively, in a daily resolution. As it can be seen for both directions, the majority of the capacity reserves corresponds to the mFRR capacity, the aFRR capacity reserves follow and the FCR products serve a smaller share of the total capacity reserves.

As shown in Figure 3.46(a) the highest upwards capacity reserve needs are defined on 05.11.2020 (32,984MWh) and the lowest total upwards capacity reserve needs are defined on 27.01.2021 (18,471MWh). More specifically, for FCR capacity reserve needs are equal to 936MWh for all days under study with the exception of days 29.01.2021-31.01.2021, where the respective needs are 1,128MWh. Also regarding aFRR capacity reserve needs, their fluctuation from day to day is minimal (10,115MWh-12,533MWh) with two exceptions on 27.12.2020 (9,385MWh) and 27.01.2021 (8,735MWh). Regarding mFRR capacity reserve needs, their daily fluctuation is defined in the range from 8,800MWh on 27.01.2021 and 19,674MWh on 07.11.2020. The daily average mFRR capacity needs for the period under study, are 14,360MWh.

As shown in Figure 3.46(b) the highest downwards capacity reserve needs are defined on 26.01.2021 (9,416MWh) and the lowest total upwards capacity reserve needs are defined on 27.12.2020 (3,846MWh). More specifically, for FCR capacity reserve needs are equal to 936MWh for all days under study with the exception of days 28.12.2020, 24.01.2021, 25.01.2021, 28.01.2021 and 31.01.2021, where the respective needs were lower (546MWh-877MWh) and the day of 29.01.2021 that defined higher at 1,008MWh. Also regarding aFRR capacity reserve needs, their fluctuation from day to day is minimal (2,235MWh-2,970MWh) with a daily average of 2885MWh. Regarding mFRR capacity reserve needs, their daily fluctuation is defined in the range from 0MWh on 27.12.2020 and 5,560MWh on 26.01.2021 with the daily average mFRR capacity needs for the period under study, defined at 3,924MWh.



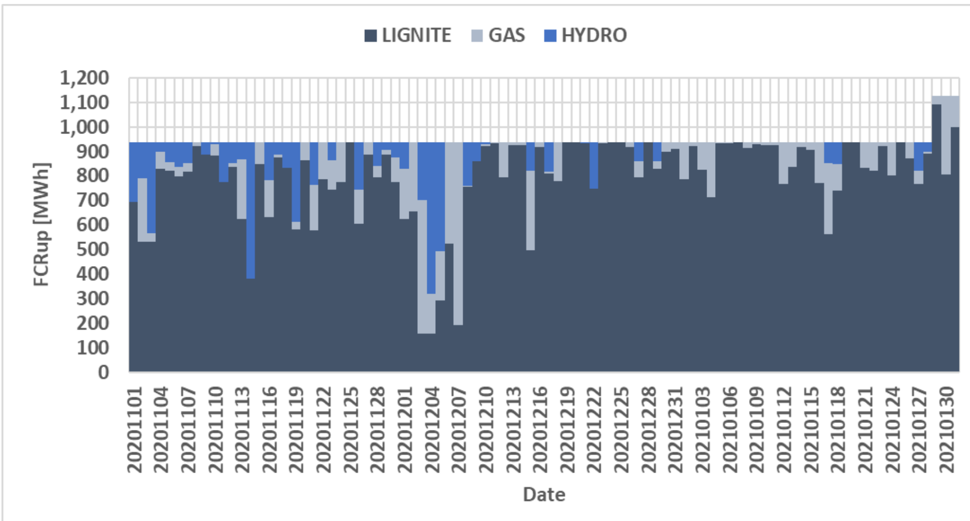
(a)



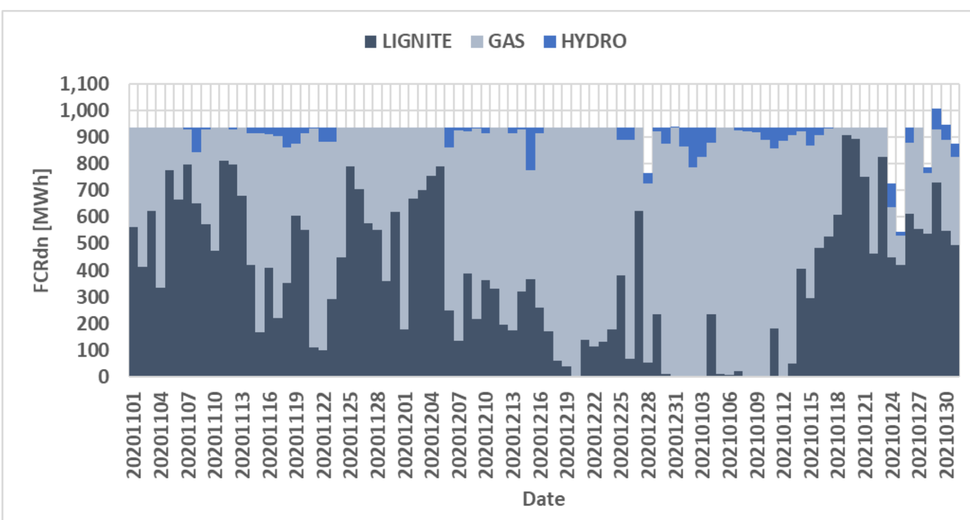
(b)

Figure 3.46. Total ISP reserves (a) upwards; (b) downwards

The FCR capacity reserves are further analyzed as shown in Figures 3.47(a) and 3.47(b), where the awarded capacities are illustrated per technology type in a daily resolution. The lignite upwards awarded FCR capacity spans from 156MWh – 17% on 03.12.2020 to 1,092MWh – 97% on 29.01.2021, with a daily average of 793MWh. The natural gas upwards awarded FCR capacity spans from 0MWh (on several days) to 742MWh – 79% on 07.12.2020, with a daily average of 86MWh. The Hydro upwards awarded FCR capacity spans from 0MWh (on several days) to 615MWh – 66% on 04.12.2020, with a daily average of 63MWh. The lignite downwards awarded FCR capacity spans from 0MWh (on several days) to 906MWh – 97% on 19.01.2021, with a daily average of 378MWh. The natural gas downwards awarded FCR capacity spans from 30MWh – 3% on 19.01.2021 to 936MWh – 100% on 20.12.2020, with a daily average of 525MWh. The Hydro downwards awarded FCR capacity spans from 0MWh (on several days) to 160MWh – 17% on 15.12.2020, with a daily average of 23MWh.



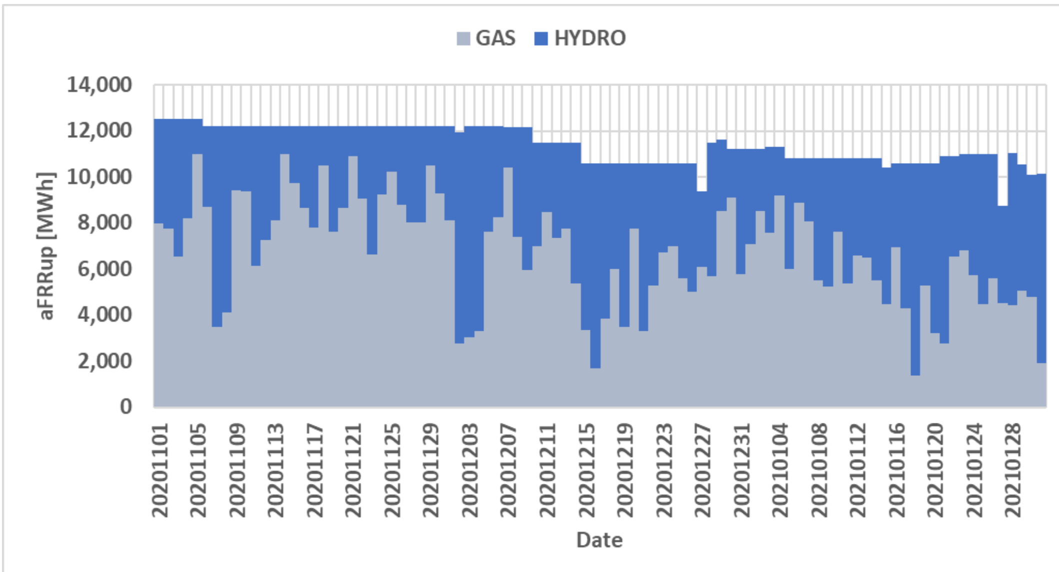
(a)



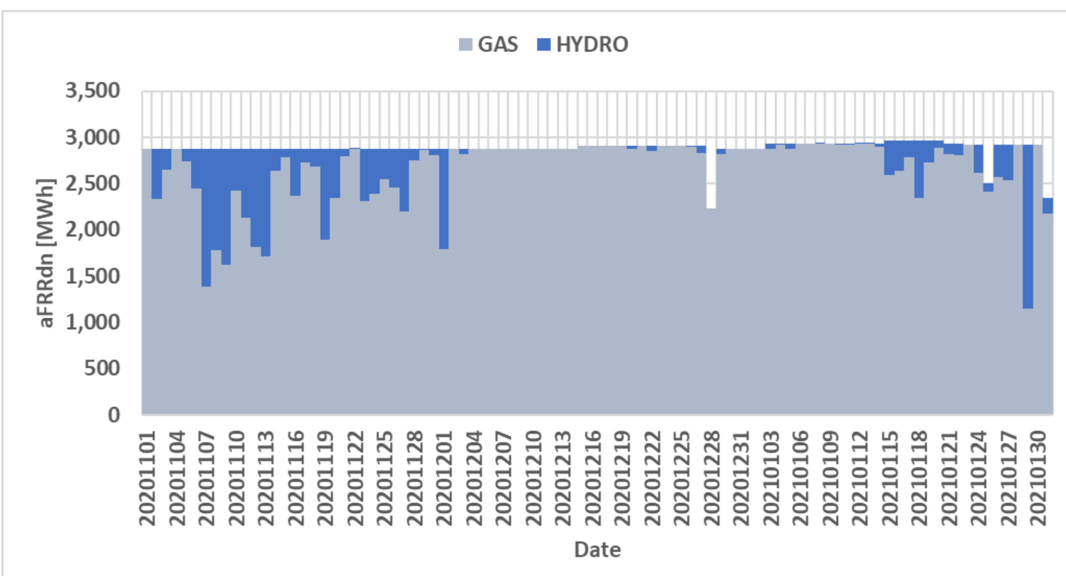
(b)

Figure 3.47. FCR ISP awarded reserves (a) upwards; (b) downwards

The aFRR capacity reserves are further analyzed as shown in Figures 3.48(a) and 3.48(b), where the awarded capacities are illustrated per technology type in a daily resolution. The natural gas upwards awarded aFRR capacity spans from 1,395MWh – 13% on 18.01.2021 to 10,991MWh – 90% on 14.11.2020, with a daily average of 6,693MWh. The Hydro upwards awarded aFRR capacity spans from 1,122MWh – 10% on 14.11.2020 to 9,205MWh – 87% on 18.01.2020, with a daily average of 4,719MWh. The natural gas downwards awarded aFRR capacity spans from 1,153MWh – 40% on 29.01.2021 to 2,935MWh – 100% on 09.01.2021, with a daily average of 2,657MWh. The Hydro downwards awarded aFRR capacity spans from 0 (on several days) to 1,762MWh – 60% on 29.01.2021, with a daily average of 227MWh.



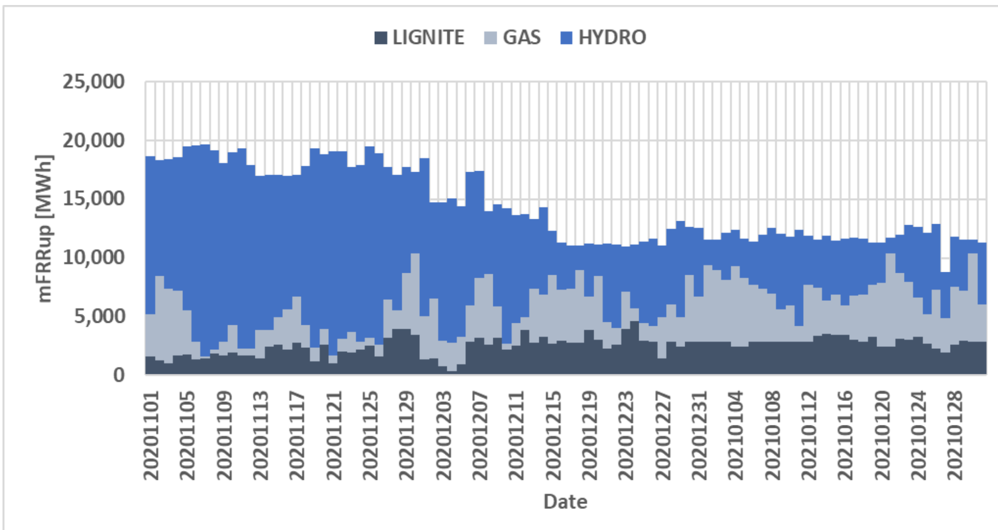
(a)



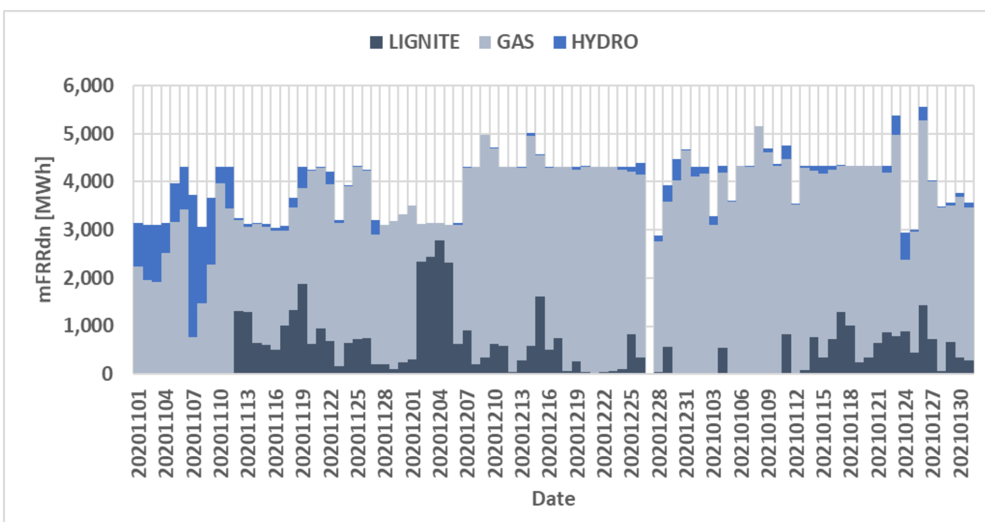
(b)

Figure 3.48. aFRR ISP awarded reserves (a) upwards; (b) downwards

The mFRR capacity reserves are further analyzed as shown in Figures 3.49(a) and 3.49(b), where the awarded capacities are illustrated per technology type in a daily resolution. The lignite upwards awarded mFRR capacity spans from 398MWh – 3% on 04.12.2020 to 4,610MWh – 41% on 24.12.2020, with a daily average of 2,537MWh. The natural gas upwards awarded mFRR capacity spans from 143MWh – 1% on 07.11.2020 to 7,990MWh – 68% on 21.01.2021, with a daily average of 3,421MWh. The Hydro upwards awarded mFRR capacity spans from 1,172MWh – 10% on 30.01.2021 to 18,078MWh – 92% on 07.11.2020, with a daily average of 8,403MWh. The lignite downwards awarded mFRR capacity spans from 0MWh (on several days) to 2,786Wh – 88% on 04.12.2020, with a daily average of 511MWh. The natural gas downwards awarded mFRR capacity spans from 0MWh on 27.12.2021 to 5,160MWh – 100% on 08.01.2021, with a daily average of 3,204MWh. The Hydro downwards awarded mFRR capacity spans from 0MWh (on several days) to 2,943MWh – 79% on 07.11.2020, with a daily average of 209MWh.



(a)



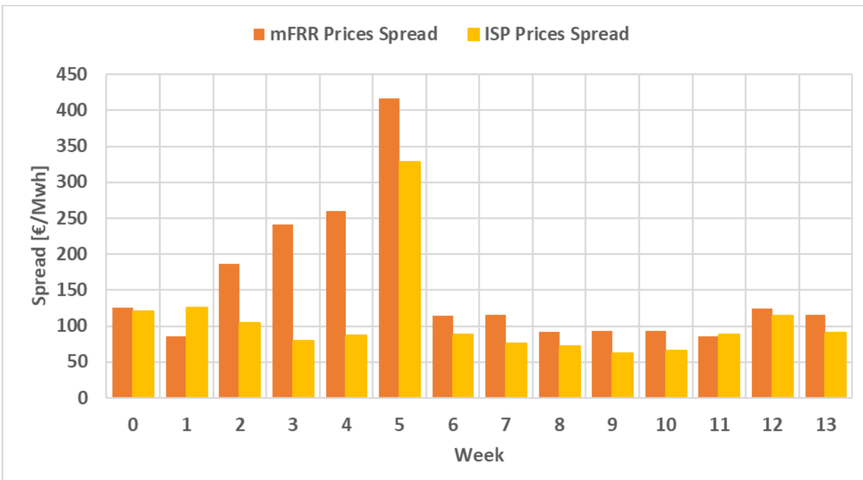
(b)

Figure 3.49. mFRR ISP awarded reserves (a) upwards; (b) downwards

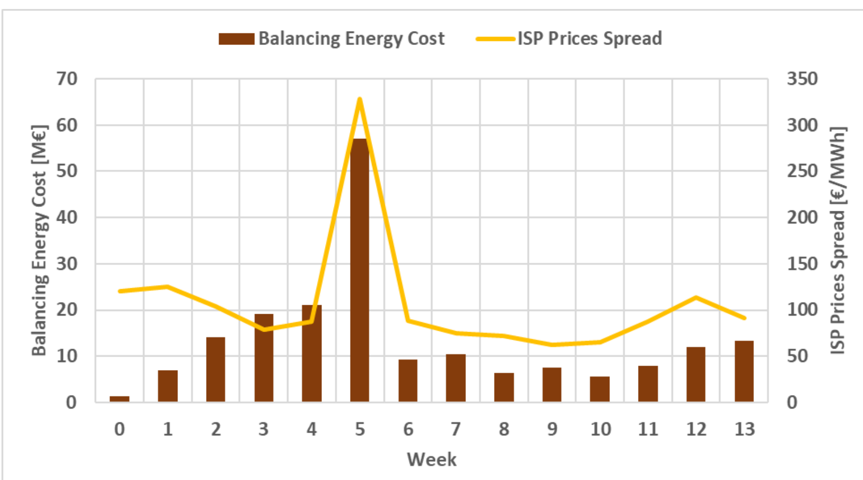
3.2.2.3 ISP Energy Clearing Prices

In the present section, the analysis is focused on the energy clearing prices as defined in the ISP results 62]. As aforementioned above, these prices are indicative and they are not used for the actual clearing of the market. However, the correlation between the spread of the ISP energy clearing prices and the mFRR marginal prices spread is investigated.

The weekly spread of the ISP clearing prices is defined according to equation (3.32) and the respective results are illustrated in Figures 3.50(a) and 3.50(b) in correlation with the mFRR marginal prices spread and the final Balancing Energy cost, respectively. As shown in the presented results, in most weeks the ISP spread is at lower levels than the mFRR spread, however, the correlation in the trend is strong. Accordingly, the ISP spread seem to give the right signals regarding the final Balancing Energy Cost as shown specifically in Figure 3.50(b).



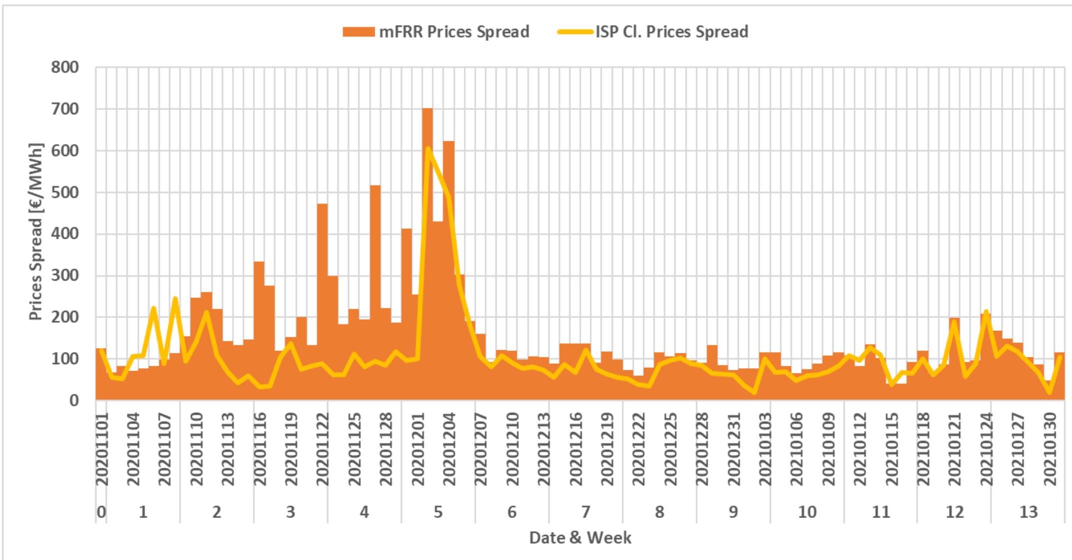
(a)



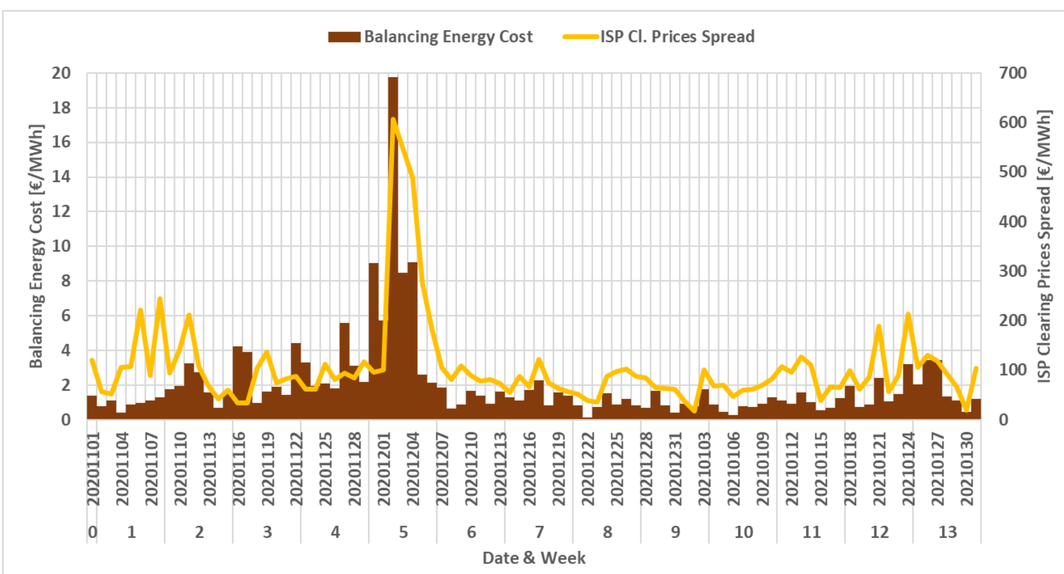
(b)

Figure 3.50. Weekly ISP Clearing Prices Spread Correlations

Accordingly, the daily spread of the ISP clearing prices is defined by applying the equations $(3.30) - (3.31)$ and the respective results are illustrated in Figures 3.51(a) and 3.51(b) in correlation with the mFRR daily marginal prices spread and the daily Balancing Energy cost, respectively. As shown in the presented results in most of the cases the ISP spread is slightly lower than the mFRR spread, with an exception of the period 10.11.2020-04.12.2020, where the mFRR spread resulted quite higher than the ISP spread. However, the correlation in the trend is strong. Accordingly, the ISP spread seem to give the right signals regarding the final Balancing Energy Cost as shown specifically in Figure 3.51(b), on a daily basis.



(a)



(b)

Figure 3.51. Daily ISP Clearing Prices Correlations

The equations that are used to define the daily and weekly spread of the ISP energy clearing prices are the following:

$$ISP\_Cl\_pr\_spread_{ISP\_p} = ISP\_Cl\_pr^{Up}_{ISP\_p} - ISP\_Cl\_pr^{Dn}_{ISP\_p} \tag{3.30}$$

$$ISP\_Cl\_pr\_spread_{day} = \frac{1}{48}\sum_{ISP\_p=1}^{48} ISP\_Cl\_pr^{Up}_{ISP\_p} - ISP\_Cl\_pr^{Dn}_{ISP\_p} \tag{3.31}$$

$$ISP\_Cl\_pr\_spread_{week} = \frac{1}{doW * 48}\sum_{day=1}^{doW}\sum_{ISP\_p=1}^{48} ISP\_Cl\_pr^{Up}_{ISP\_p} - ISP\_Cl\_pr^{Dn}_{ISP\_p} \tag{3.32}$$

4 Spot Markets Liquidity

In the present chapter, the liquidity of the spot markets is estimated per market based on the total traded volumes and the economic inflows of thermal and hydro producers, in a monthly and daily resolution.

4.1 Traded Volumes of Energy

In the present sub-chapter, the liquidity of the three spot markets is estimated based on the traded volumes of energy in the respective market. The traded energy volumes for DAM and IDM [58] are calculated according to equation (4.1) and the traded energy volumes for BM [62] are calculated according to equation (4.2).

$$Volumes_{DAM\ or\ IDM}^{Total} = Volumes_{DAM\ or\ IDM}^{BUY} + Volumes_{DAM\ or\ IDM}^{SELL} \tag{4.1}$$

$$Volumes_{BM}^{Total} = Volumes_{BM}^{Act.En.Up} + Volumes_{BM}^{Act.En.Dn} \tag{4.2}$$

In Figure 4.1 the resulted traded volumes of energy are presented per market on a monthly resolution. It is obvious from the respective Figure, that the most liquid market is the DAM, the second liquid market corresponds to the BM and the least liquid market is the IDM. For all three markets, the traded volumes increased from month to month. Furthermore, the liquidity in BM accounts on average at 7.04% compared to the DAM, whereas the liquidity in IDM accounts for less than 2.00% compared to the DAM.

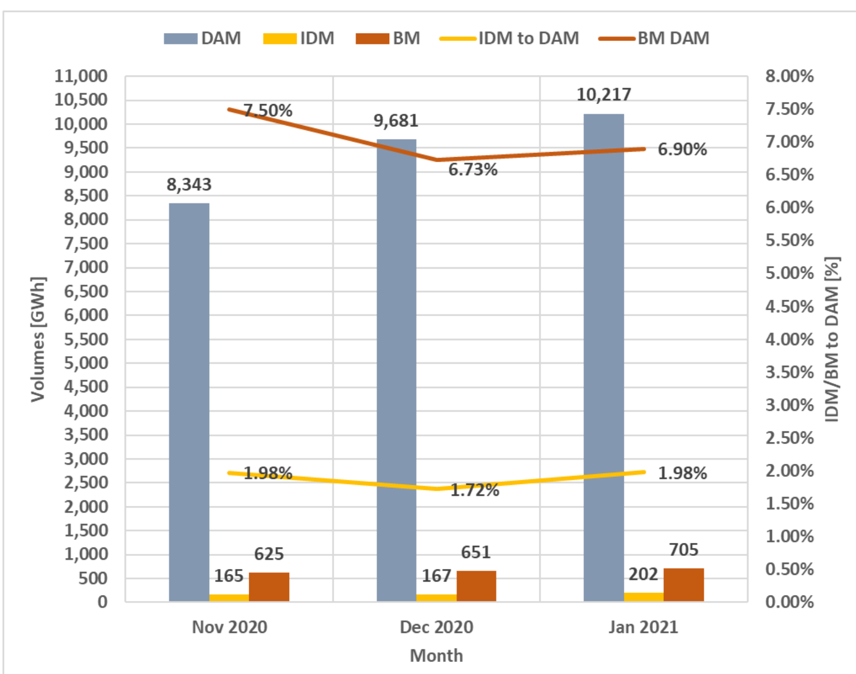


Figure 4.1. Spot Markets liquidity estimation based on traded energy volumes

4.2 Domestic Production Inflows

In the present sub-chapter, the liquidity of DAM and BM is estimated based on the economic inflows from each market, in a monthly resolution. The IDM is not considered in the present analysis since the traded volumes in IDM are less than 2.00% compared to DAM and the MCPs of LIDAs were relatively low compared to the BM prices, as presented in the previous sections of the study. Although, the liquidity in BM accounts also for a relatively small percentage of traded volumes compared to DAM (on average 7.04%) it is considered in the present analysis, since the BM marginal prices had a greater impact on the economic results of the respective market. Furthermore, the estimation of liquidity considers the market inflows from the thermal (Lignite & Natural Gas) and Hydro generation units. The focus is given in these technologies for comparison reasons, since they are the only dispatchable assets that participate in the BM apart from the DAM. Finally, also for comparison reasons between DAM and BM, the reference to BM inflows correspond to the inflows only from the Balancing Energy Market and not the Capacity Balancing Market.

The estimation of economic inflows per generation technology from the DAM is based on the equations $(4.3)-(4.4)$, where the volumes per mtu were estimated based on the ISP indicative market schedule and the ISP activated energy, and more specifically, by subtracting the activated energy from the indicative ISP market schedule. The resulted market schedule of the "reverse" calculation from ISP results [62], is assumed to be the market schedule of DAM, based on the assumption that in total the traded energy volumes in the IDM are essentially lower than DAM.

$$DAM\_Inflows_{asset}^{day} = \sum_{mtu=1}^{24} Volumes_{asset}^{mtu} * MTU_{mtu}^{day} \tag{4.3}$$

$$DAM\_Inflows_{technology}^{day} = \sum_{asset=1}^{noA} DAM\_Inflows_{asset}^{day} \tag{4.4}$$

Regarding the economic inflows from the BM, there are no respective data for the awarded volumes per production unit, that are eligible for remuneration. However, from the available public data [62], the economic inflows of all the Thermal and Hydro generation units can be considered as the total Balancing Energy Cost. The results of the economic inflows are shown in Figures 4.2 and 4.3 in a daily and monthly resolution, respectively.

More specifically, in Figure 4.2 the inflows are illustrated for the DAM by generation technology, where the Natural Gas generation units acquired the majority of the inflows from DAM, the Lignite generation follows and the least remunerated assets were the Hydro plants. Regarding the inflows from the BM, these cannot be presented per technology, however, as shown in the respective Figure, the total inflows of BM surpassed the total inflows of DAM on the dates: 11.11.2020 (+0.33M€), 22.11.2020 (+1.48M€), 30.11.2020 (+3.07M€), 02.12.2020 (+10.84M€) and 04.12.2020 (+0.75M€).

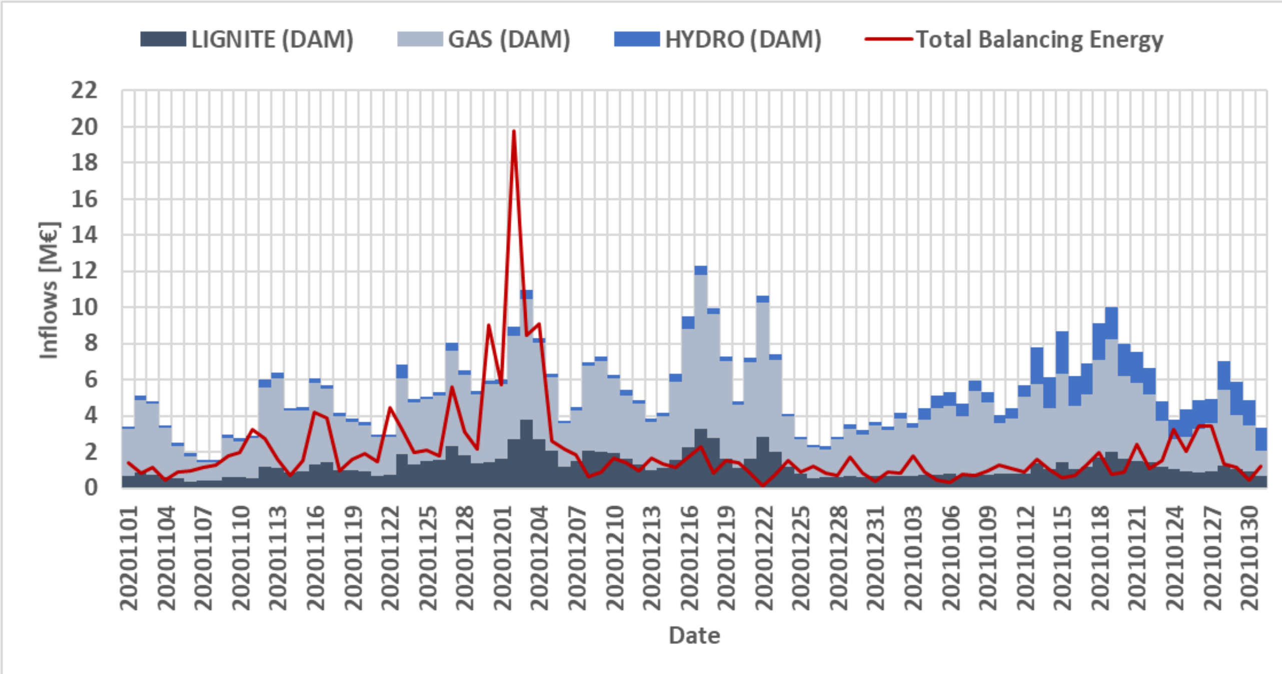


Figure 4.2. Daily economic inflows per market

As shown in Figure 4.3 the most liquid market is the DAM with economic inflows for the Thermal and Hydro producers at 132M€, 188M€ and 177M€ for November, December and January respectively, whereas the economic inflows from the BM for the respective months were 69M€, 77M€ and 41M€.

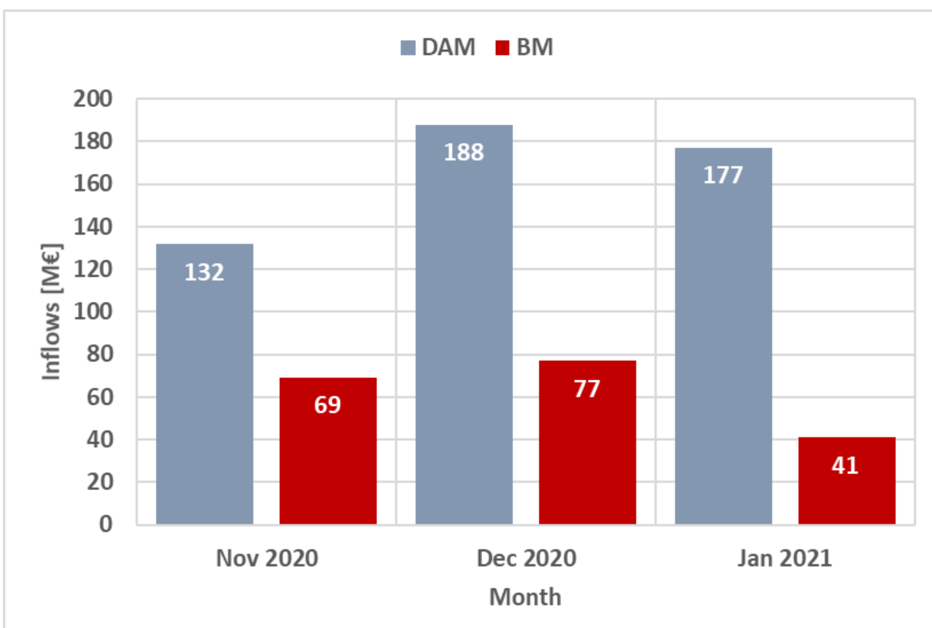


Figure 4.3. Monthly economic inflows per market

5 Historical Development of Wholesale Power Prices

In the present chapter, the development of the Day-Ahead Market prices is presented considering the previous recent years in the Greek Power Market, as well as the formation of the weighted average wholesale price, which is the main component of the final cost of energy on the retail power market.

5.1 Day-Ahead Wholesale Price Development

In the present sub-chapter, the development of the Day-Ahead Market price is presented and analyzed for the recent previous years and more specifically, for the years 2016 – 2020 [58, 60]. It is noted that the wholesale day-ahead prices prior to the implementation of EU Target Model framework in the Greek Power Market - until October 2020-, were set through the Day-Ahead Scheduling (DAS) procedure, which was the model for the organization and operation of the domestic wholesale market, and through which all electricity generated, shipped, and consumed in the country for the next day was traded. In this model, the determination of the price (System Marginal Price - SMP) was the result of a complex algorithmic application (objective function optimization) that seeks to minimize the allocation cost of production units, based on technical data governing their operation as well as System's operation. In the scope of EU Target Model, the resulted wholesale Day-Ahead prices is called Market Clearing Price (MCP) and the determination of MCP does not consider other components, as the system constraints or the capacity reserves. Hence, the MCP does not reflect the same costs as the SMP, nevertheless, the MCP continuous to constitute the most robust signal in the domestic power market.

In Figure 5.1 the development of the wholesale Day-Ahead prices is presented from January 2016 to January 2021.

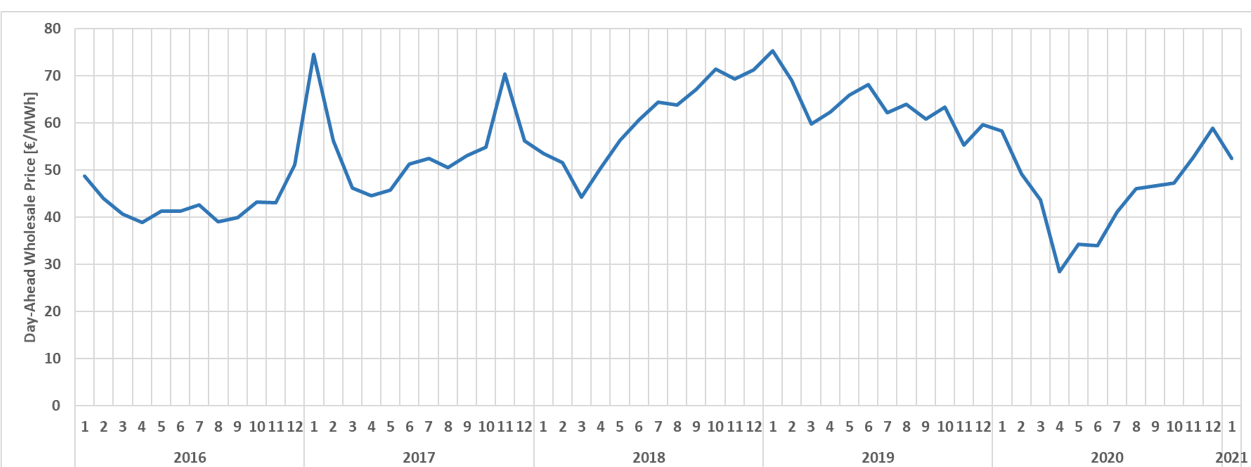


Figure 5.1. Day-Ahead Wholesale price development of the Greek Power Market (01/2016-01/2021)

The illustration of the historical data of the day-Ahead wholesale prices [58] is presented in Figure 5.2, for the years 2016 to 2020, in a monthly resolution, in order to show the seasonality. Regarding the year 2020 the line is distinguished between the DAS and DAM periods. The year with the lowest prices is 2016, excluding from the analysis the low prices from March 2020 to August 2020, as they resulted due to the Covid-19 crisis. Focusing on November 2020 and December 2020, the prices are lower from all the other years included in the graph, with the exception of 2016 and 2017.

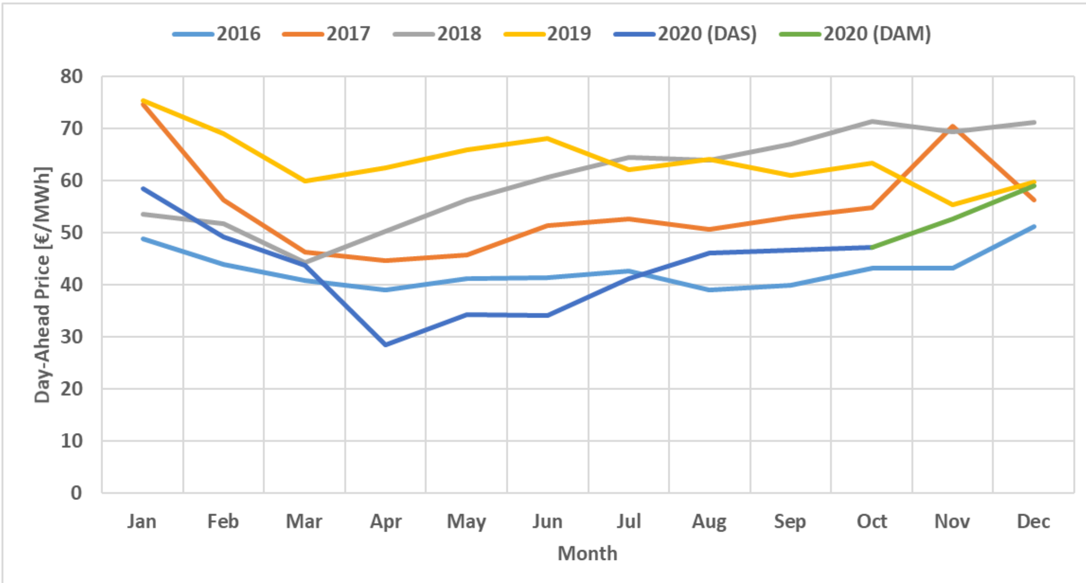
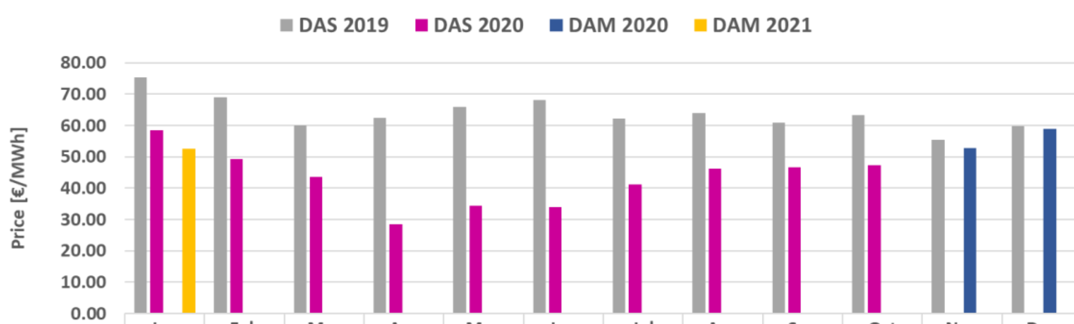


Figure 5.2. Day-Ahead Wholesale price development of the Greek Power Market (01/2016-12/2020)

Another illustration of the Day-Ahead wholesale prices is presented in Figure 5.3 focusing on the years 2019 and 2020. As it shown the average day-ahead monthly prices for the three months under study (i.e., November, December, January), are lower than the corresponding months in 2019. The price of January 2021 is also lower than the price in January 2020.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
DAS 2019	75.28	69.01	59.87	62.40	65.91	68.14	62.14	64.02	60.91	63.33	55.35	59.68
DAS 2020	58.38	49.23	43.66	28.51	34.27	34.03	41.13	46.13	46.62	47.23		
DAM 2020											52.66	58.93
DAM 2021	52.52											

Figure 5.3. Day-Ahead Wholesale price development of the Greek Power Market (01/2019-01/2021)

In Figure 5.5 the development of the Greek Day-Ahead wholesale price is presented in comparison with the European average of the Day-Ahead wholesale prices for the period from 11/2019 to 01/2021. As shown in the respective Figure, Greece's average monthly Day-Ahead wholesale price for January 2021 was lower than the corresponding European average [63].

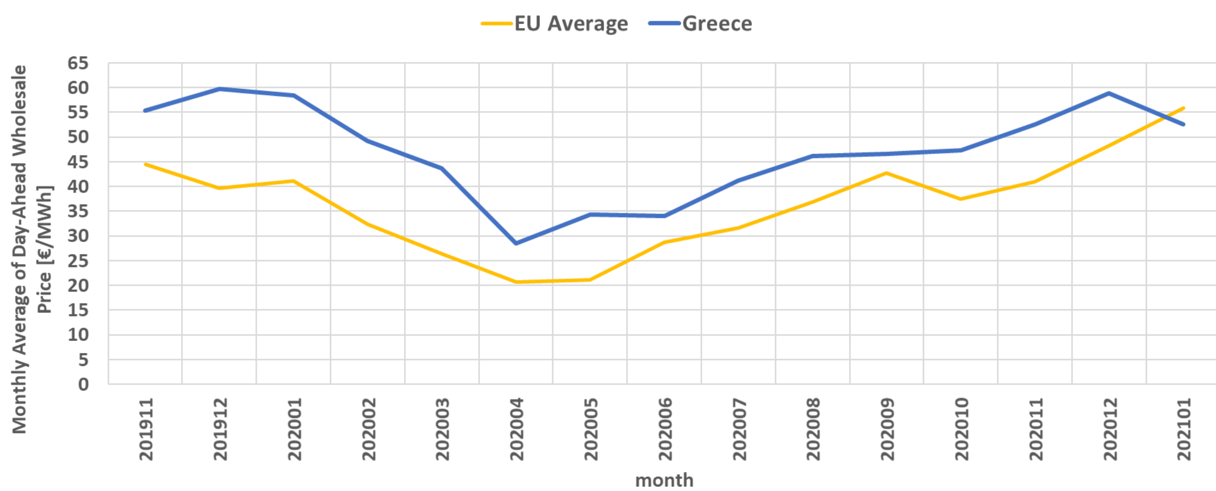


Figure 5.4. Greek Day-Ahead prices development compared to EU Average (11/2019-01/2021)

5.2 Weighted Average Wholesale Market Price

In the current sub-chapter, the weighted average wholesale market price is analyzed, which refers to the cost of wholesale market that a supplier faces and its fluctuations may be reflected ultimately to the end customers. The suppliers may impose clauses to their end-customers in order to recover part of the unforeseen increase of their wholesale cost. The total weighted average wholesale market price may include additional components in addition to the Day-Ahead prices. These components may refer to costs related to State-Aid support, as the “RES Aid” that supports the RES development and the Capacity Remuneration Mechanisms (CRMs) that contribute to the missing money problem of the power producers. According to the EU regulation 943/2019, the state-aid schemes should be a last resort measure due to the fact that they result market distortion and hinder the formation of the right market signals. Other additional components to the total wholesale cost, may refer to the structure of the market and the clearing procedures of the Market Participants, as the Imbalance costs (IMB), the Uplift Accounts Cost (UA) and the yearly Account Clearing cost.

In Figures 5.5 the total weighted average market price is illustrated, as well as the analytical corresponding components [65], additional to the Day-Ahead wholesale prices, from January 2019 to January 2021, in a monthly basis. As shown in the respective Figure the Uplift Accounts cost has the largest share in the additional component’s costs for the majority of the illustrated months.

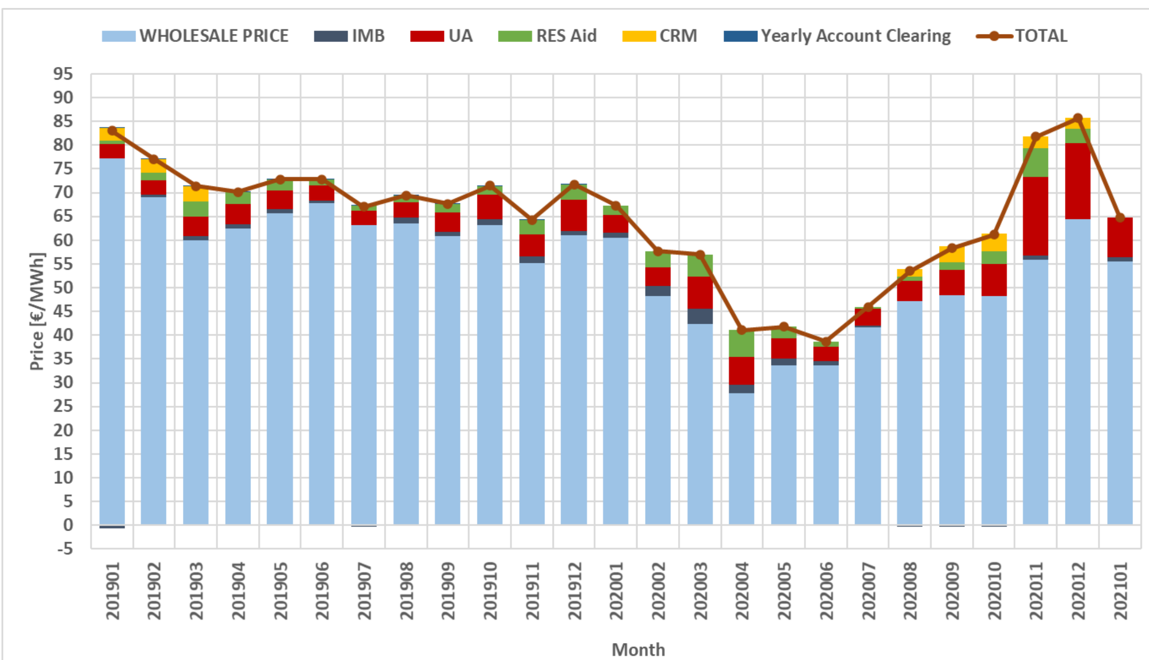


Figure 5.5. Greek Power Market Wholesale Cost Components (01/2019-01/2021)

For a more consice illustration of the additional components' costs, in Figure 5.6 are presented the shares of the total monthly wholesale market prices, that correspond to the the day-Ahead prices and the total cost of the additional components. For the months under study (11/2020-01/2021) the additional components' costs account for 32% in November, 25% in December and 14% in January. The afroementioned shares correspond to the Uplift Accounts costs as resulted from the Balancing Market in the transitional months -November 2020 and December 2020-, as well as due to the RES State-Aid support cost that was passed on to the suppliers. However, the Greek Power Market, is rapidly maturing under the EU Target Model framework, as the Uplift Accounts cost is essentially decreased in January 2021, as well as the state aid support schemes are no longer applicable, complying to the Euroepean legislative framework, that dictates that the inflows and outflows of the Market Participants should be handled by the efficient operation of the market itself.

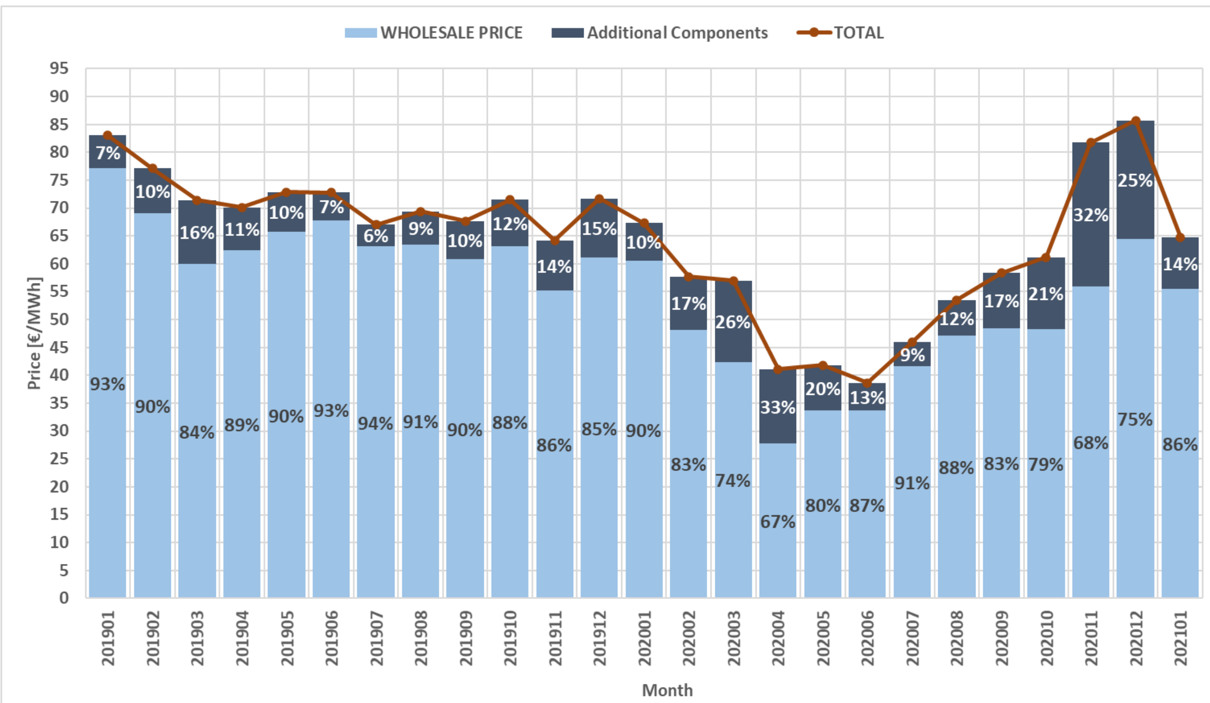


Figure 5.6. Greek Power Market Wholesale Cost monthly development (01/2016-01/2021)

Conclusions

The realization of a sustainable future in Europe is characterized by a decarbonized economy, where the Renewable Energy Sources play a central role. However, the renewable generation is inherently intermittent as it is highly affected by weather conditions. Thus, the increasing penetration of RES in the generation mix is a challenge for the energy sector as a whole, in terms of system reliability and increased flexibility needs in order to ensure the efficient continuity of supply of clean and affordable energy to the end customers. The market framework in which the RES participate in, plays a crucial role in managing the intermittency of generation. The EU Target Model framework enables the harmonization of the market rules in a European-wide scale towards the realization of a single Internal Energy Market (IEM).

The Greek Power Market is re-organized as of 1st of November 2020, according to the EU Target Model framework and four successive markets are provisioned. The Forward Market (FM), Day-Ahead Market (DAM), the Intra-Day Market (IDM) and the Balancing Market (BM). The present Thesis is an attempt to interpret and present the real market data as resulted from the first three months of the EU Target Model implementation in the Greek Power Market, focusing on the three Spot Markets (i.e., DAM, IDM, BM). The Implementation of the EU Target Model serves the better participation of RES in the market. In Greek power market the RES are not yet acting as BRPs, however, the first three months of EU Target Model implementation are analyzed in order to evaluate the conditions of the market towards the steps forward.

Regarding the MCP results for DAM, the average monthly MCP was resulted at 52.66€/MWh for November, 58.93€/MWh for December and 52.52€/MWh for January, with the average daily spread at 46.98€/MWh for November, 56.99€/MWh for December and 49.38€/MWh for January, which shows that December was the most expensive month with the highest volatility.

Regarding the MCP results for LIDA1, the average monthly MCP was resulted at 53.21€/MWh for November, 60.26€/MWh for December and 53.57€/MWh for January, with the average daily spread at 56.00€/MWh for November, 64.68€/MWh for December and 59.68€/MWh for January, which shows that December was the most expensive month with the highest volatility as well as DAM.

Regarding the MCP results for LIDA2, the average monthly MCP was resulted at 51.84€/MWh for November, 59.09€/MWh for December and 49.90€/MWh for January, with the average daily spread at 50.50€/MWh for November, 73.08€/MWh for December and 61.92€/MWh for January, which shows that December was the most expensive month with the highest volatility as well as DAM.

Regarding the MCP results for LIDA3, the average monthly MCP was resulted at 56.03€/MWh for November, 54.98€/MWh for December and 48.07€/MWh for January, with the average daily spread at 53.31€/MWh for November, 63.77€/MWh for December and 49.94€/MWh for January, which shows that November was the most expensive month and the month with the highest volatility was December.

Regarding the DAM energy mix, the natural gas generation resulted the highest share in all three months (38%-42%), followed by RES (24%-32%). In January the Hydro generation increased to 13% instead of 2% in November and December. The Lignite generation was increased in December at a share of 16% in oppose to November (13%) and January (12%). That explains also the increased MCP in December. On the other hand, as shown from the analysis, in days with increased RES penetration and Hydro generation the MCP was decreased.

Regarding the DAM demand mix, the LV Load accounts for the “steady” 57% of the total demand for all three months under study. The MV Load range between 15% and 19% and the HV Load between 14% and 16%. The exports increased in December at 10% compared to 5% in November and in January resulted at a higher percentage of 12%. The increase of imports in January is associated with the increased RES and Hydro production in the same month, which resulted low MCP for the respective days. Regarding the load profiles, the HV Load is higher on weekends instead of the weekdays, MV Load is quite lower in weekends in comparison to the weekdays and LV Load’s deviation between weekdays and weekends is relatively minimal.

Regarding Cross-Border Trading, for the period under study (01.11.2020-31.01.2021), total imports were scheduled at 1,793.24GWh and total exports at 1,279.96GWh. More specifically, the majority of the imported quantities correspond to the Bulgarian border with 619.01GWh and the Italian border with 433.84GWh. The North Macedonian border’s imports were 311.07GWh, the Albanian border’s imports 246.54GWh and the minimum imports correspond to the Turkish border at 182.77GWh. The highest exporting quantities correspond to the Italian border with 446.68GWh and the North Macedonian border with 358.87GWh. The exports to Albania were 244.94GWh, to Bulgaria 208.07GWh and to Turkey 21.40GWh. The Greece was a net importer in November and December and net exporter in January.

Regarding the Balancing Market, the total Balancing Market cost comprises of the Balancing energy cost and the Balancing Capacity cost. The total Balancing Energy Cost constitutes on average the 89% of the total BM cost in comparison to the Balancing Capacity cost that accounts on average the rest 11% of the total BM cost. Statistically, the maximum Balancing Energy cost resulted on week 5 at 57.15M€ and more specifically, the days with increased BM cost were 30.11.2020 (9.04M€), 02.12.2020 (19.74M€), 03.12.2020 (8.47M€) and 04.12.2020 (9.06M€). The reason of the resulted costs is the scarcity market conditions that took place in the aforementioned period. This is justified by considering the offered prices of the respective week (Figure 3.31), and especially considering the mFRR marginal prices (Figure 3.16), where the majority of the prices were allocated in lower levels and only a small percentage of the prices was allocated in higher levels. Regarding the ISP offers, the number of records that are included in the relevant order book, affects the mFRR marginal prices and subsequently the Balancing Energy cost as shown in Figure 3.25.

The resulted cost corresponds to the activated volumes and more specifically, it corresponds to the absolute sum of activated volumes in both directions. Moreover, the introduced index of net to total activated energy volumes ratio, shows that the balancing energy cost is lower as the respective index gets higher. Furthermore, the total balancing cost corresponds also to the mFRR marginal prices. The mFRR marginal prices spread constitutes an index that models the prices fluctuations and subsequently provides a signal for the Balancing Energy cost as depicted from Figure 3.10.

Regarding the activated balancing energy, the ISP resulted volumes are always lower in comparison to the finally settled activated energy volumes in both directions. The total settled activated balancing energy for the period under study accounts for 909.89GWh in the upwards direction and 1,071.71GWh in the downwards direction, whereas the ISP results indicate 617.26GWh and 751.95GWh respectively. Focusing on the ISP resulted volumes, for the period under study, the upwards activated balancing energy volumes are awarded to Lignite at 86.80GWh – 14.06%, Natural Gas at 320.26GWh – 51.89%, Hydro at 205.66GWh – 33.37% and Pumping at 4.20GWh – 0.68%. The downwards activated balancing energy volumes are awarded to Lignite at 47.04GWh – 6.26%, Natural Gas at 668.53GWh – 88.91%, Hydro at 34.51GWh – 4.59% and Pumping at 1.87GWh – 0.25%.

Regarding the capacity reserves, for the period under study, the biggest share for the upwards FCR was awarded to Lignite generation, while regarding the downwards FCR the biggest share was awarded to Natural Gas generation. More specifically, for upwards FCR the shares resulted as follows: Lignite 73.00GWh, Natural Gas 7.93GWh and Hydro 5.76GWh. Respectively, for downwards FCR the shares were: Lignite 34.77GWh, Natural Gas 48.30GWh and Hydro 2.15GWh. For both direction of aFRR capacity reserves the majority was awarded to Natural Gas. More analytically for the upwards aFRR the Natural Gas was awarded with 616GWh and the Hydros were awarded with 434GWh, whereas for downwards aFRR capacity reserves the shares correspond to Natural Gas equal to 244GWh and for Hydros equal to 21GWh. Regarding the mFRR upwards capacity reserves, the majority was awarded to Hydros and the shares were analytically awarded as follows: Lignite 233GWh, Natural Gas 315GWh and Hydro 773GWh, whereas for downwards mFRR capacity reserves the majority was awarded to Natural Gas and the analytical shares correspond to: Lignite 47GWh, Natural Gas 295GWh and for Hydro 19GWh.

The ISP Energy Clearing prices spread is highly correlated with the mFRR marginal prices spread. For the vast majority of the cases the ISP prices spread is lower than the corresponding mFRR prices spread, with an exception of week 0, 1 and 11, as shown in Figure 3.51. However, the ISP Energy Clearing prices spread constitutes a valuable signal regarding the estimation of the Balancing Energy cost.

Regarding the liquidity evaluation of the spot markets, DAM is the most liquid market in terms of traded volumes, as well as regarding the economic inflows of the domestic Thermal and Hydro producers. The second more liquid market is the Balancing Market, where the traded volumes in BM correspond on average to 7.04% of the corresponding traded volume in DAM. The IDM is the least liquid market, where the traded volumes in IDM correspond on average, to less than 2.00% of the corresponding volumes of DAM. Furthermore, in terms of producers' economic inflows, the BM corresponds to 187M€ in comparison to the 497M€ of DAM, considering the three months under study. More specifically, the producers' economic inflows from BM as a percentage of the DAM's respective inflows were 52.27% for November, 40.96% for December and 23.16% for January.

Considering also the historical data of the Day-Ahead prices, in the months under study, the corresponding prices were lower compared to the recent previous years. More specifically, the monthly average price of November 2020 was the lowest price of month November since 2017, the monthly average price of December 2020 was the lowest price of month December since 2018, and the monthly average price of January 2021 was the lowest price of month January since 2017. It is in fact underlined that in January, the Greek Power System resulted lower Day-Ahead Price compared to the European average, on a monthly basis.

The largest component of the weighted average wholesale market price is the Day-Ahead wholesale price which constitutes on average the 85% of the total wholesale market price, considering the period from 01/2019 to 01/2021. The residual 15% corresponds to other additional components, of which 8% corresponds on average to the Uplift Accounts cost. More specifically, for the three months under study the share of the additional components in the total wholesale market price is 32%, 25% and 14% for November, December and January respectively, with the Uplift Accounts cost being 20% 19% and 13% respectively.

In conclusion, as it is admitted from the results of the present study, the implementation of the EU Target Model in the Greek Power Market has passed through a transitional period, especially focusing on December 2020, where there were resulted high costs on both Day-Ahead Market and the Balancing Market. However, the analyzed data of January 2021 show a strong evidence that the market is rapidly maturing and becomes capable of handling its own dynamics. More specifically, the MCP in DAM, which constitutes the strongest market signal, resulted at a lower price than the previous months under study, but also resulted lower from the corresponding months in the previous years, as well as against the European average in 2021. Furthermore, the maturity of the market is admitted through the TSO actions, where the total capacity reserves requirements are gradually decreasing and the simultaneous activation of upwards and downwards balancing energy is better handled, according to the net to total ratio index. The Market Participants are also shown to adopt the new landscape as the offered prices for their participation in the BM are de-escalated, which shows that they follow more competitive strategies that ultimately are reflected on the reduced BM cost. Subsequently, the weighted average market price that the suppliers and ultimately the end-customers experience, is also reduced in January 2021 and more specifically, the additional components of state-aid support are no longer applicable, as derived from the compliance of Greece to the relative European regulatory and legislative framework, and furthermore the remaining largest component which is the Uplift Accounts cost, was essentially reduced compared to November 2020 (-49%) and compared to December 2020 (-48%). So, it is clear that the Greek Power Market has successfully made a step forward, and this is also validated based on the market statistics. The implementation of the Target Model is the first major step for Greece towards the Internal Energy Market, where the benefits of increased RES penetration and free power flow between the European countries will be fully revealed and reflected to better life standards in a European-wide scale. The EU Target Model is a strong step towards sustainability.

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