



– Deliverable D5.1 –

Modeling of VPPs for their Optimal Operation and Configuration

Authors:

Álvaro Ortega – *Universidad Pontificia Comillas, Instituto de Investigación Tecnológica (IIT)*

Oluwaseun Oladimeji – *Universidad Pontificia Comillas, Instituto de Investigación Tecnológica (IIT)*

Hadi Nemati – *Universidad Pontificia Comillas, Instituto de Investigación Tecnológica (IIT)*

Lukas Sigrist – *Universidad Pontificia Comillas, Instituto de Investigación Tecnológica (IIT)*

Pedro Sánchez-Martín - *Universidad Pontificia Comillas, Instituto de Investigación Tecnológica (IIT)*

Luis Rouco – *Universidad Pontificia Comillas, Instituto de Investigación Tecnológica (IIT)*

Enrique Lobato – *Universidad Pontificia Comillas, Instituto de Investigación Tecnológica (IIT)*

Mario Biencinto - *Centro de Investigaciones Energéticas, Medioambientales y Tecnológicas (CIEMAT)*

Ione López – *Iberdrola Clientes España (IBR)*



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Executive summary

This Deliverable, which is the major output of Task T5.1, proposes a novel Dynamic Virtual Power Plant (DVPP) planning model, that is composed, exclusively, by Renewable Energy Sources (including hydro, wind, solar PV, solar thermal and biomass), and flexible demands. The model considers the optimal configuration and operation of the DVPP for different business cases. The goal is to demonstrate that, by appropriately combining the features and efforts from RESs of different nature that are currently installed and operating in a power system, one can achieve higher economical and operational benefits than other solutions that imply the installation of large electrochemical (battery) energy storage systems (BESSs).

The DVPP model proposed in this document is the first stone that will pave the way towards a tool that is being developed in this WP that will provide system operators, aggregators, retailers and consumers with the instruments to operate RESs in a viable, competitive and reliable way.

To this aim, the DVPP optimization model includes features to account for the different characteristics of the DVPP itself, the electrical network to which it is connected, and the market mechanisms that can help the DVPP become economically efficient. Such characteristics include: i) the electrical network in the form of, e.g., nodal power balances and line active power flow limits; (ii) the DVPP components, such as generating units, demands, and RES-based storage units (pumped-hydro, solar thermal); (iii) the markets in which the DVPP may participate, such as energy markets and ancillary service markets; and (iv) the uncertainties that characterize several parameters of the model, such as stochastic energy sources (wind and sun), market prices, and demand behavior.

Different business models for the DVPP have been identified in the form of the electric energy and power markets that can be suitable for its participation. Among all market schemes currently implemented across Europe, the most relevant from the DVPP perspective are the day-ahead and intra-day markets from the energy perspective, and the secondary reserve market from the power (ancillary service) perspective. With this in mind, the DVPP manager could select the appropriate objective functions within the proposed model presented so that the DVPP can participate in one or more of such markets. Other markets with some potential for the DVPP (mainly other ancillary service markets) have also been identified and described in this document.

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Acronyms

AGC	Automatic Generation Control
aFRR	Automatic Frequency Restoration Reserve
ASM	Ancillary Service Market
BESS	Battery Energy Storage System
D-RES	Dispatchable Renewable Energy Source
ND-RES	Nondispatchable Renewable Energy Source
DAM	Day-Ahead Market
DER	Distributed Energy Resource
DNI	Direct Normal Irradiance
DoE	Department of Energy
DVPP	Dynamic Virtual Power Plant
ESS	Energy Storage System
EV	Electric Vehicle
FCR	Frequency Containment Reserve
FFR	Fast Frequency Response
FRR	Frequency Restoration Reserve
G2V	Grid-to-Vehicle
IDM	Intra-Day Market
mFRR	Manual Frequency Restoration Reserve
OMIE	Operador del Mercado Ibérico de Energía (Iberian Energy Market Operator)
OPF	Optimal Power Flow
PB	Power Block
PCC	Point of Common Coupling
PHES	Pumped Hydroelectric Energy Storage
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PV	Photovoltaic
REE	Red Eléctrica de España
RES	Renewable Energy Source
RO	Robust Optimization

RR	Replacement Reserve
SCADA	Supervisory Control and Data Acquisition
SO	System Operator
SoC	State-of-Charge
SOS-2	Special Ordered Set - Type 2
SRM	Secondary Reserve Market
STU	Solar Thermal Unit
TRM	Tertiary Reserve Market
TSO	Transmission System Operator
V2G	Vehicle-to-Grid
VPP	Virtual Power Plant
WP	Work Package

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1 Introduction

1.1 WP5 and Task 5.1 Overview

The main goal that is pursued in this Work Package (WP) is to investigate how to optimally configure and operate a Dynamic Virtual Power Plant (DVPP) composed of Renewable Energy Sources (RESs) - both dispatchable and nondispatchable - and flexible loads so that it can outperform, from the economical and operation points of view, solutions based on electrochemical battery energy storage systems (BESSs). With this aim, the first task T5.1 of this WP is focusing on the development and formulation of the model of the DVPP that will be later implemented and used to analyze the optimal operation and configuration of such a DVPP.

1.2 Objectives and Outline of the Deliverable

The optimization model of the DVPP needs to be general enough to account for all the features and particularities of (i) the electrical network, (ii) the DVPP components, (iii) the markets in which the DVPP may participate, (iv) the uncertainties that characterize several parameters of the model, and (v) the constraints regarding the close-to-real-time operation of the DVPP. However, to formulate such a model is an arduous task that needs to be meticulously performed. It is not viable to formulate the *complete* model as a whole, to be later implemented and tested all at once. Instead, such a formulation needs to be developed in a modular manner, and careful tests need to be carried out progressively to validate each feature that is being added into the model.

With this aim, this deliverable D5.1 presents and discusses the core of the DVPP model for its optimal operation and configuration. The model core includes:

- the business models of a DVPP participating in the electric energy markets (day-ahead and intra-day), and in the main ancillary service market that is currently implemented (secondary reserve market);
- the constraints that represent each of the assets that compose the DVPP, comprising several RES technologies (hydro, biomass, wind, solar photovoltaic (PV), concentrated solar plants), flexible demands (industrial, residential, and others), and storage devices (pumped hydro, solar thermal units with storage);
- the constraints that represent the electrochemical BESSs; and
- the constraints that represent the electric grid to which the DVPP is connected.

Although not explicitly formulated, the deliverable also thoroughly discusses relevant aspects related to the characterization of the uncertainties that characterize some of the parameters of the model, such as the stochastic profiles of wind speed and solar irradiation, the prices of the different markets, and the available flexibility from demands depending on their daily consumption profiles.

Future Tasks of this WP will focus on the formulation and implementation of other functionalities of the DVPP model such as the robustness against uncertainties, the close-to-real-time operation, and the possibility that the DVPP can participate in other, *a priori* less relevant

markets which nevertheless show some potential. Such functionalities will be gradually implemented and tested along with the model core presented in this document, and will be duly reported in future Deliverables of this WP.

1.3 Structure of the Deliverable

The remainder of this Deliverable is organized as follows.

Chapter 2 provides a general overview of the role of conventional Virtual Power Plants (VPPs) and the dynamic counterpart proposed in the POSYTYF project, the DVPP, in the electric energy trading business. The different energy market floors that are broadly implemented in most European countries, namely the day-ahead and intra-day markets, are also described.

Chapter 3 follows with a detailed description of the main ancillary service markets that are available to DVPPs based on the broad selection of ancillary services that an aggregation of RESs, flexible loads and storage devices can provide to an electric grid.

Chapter 4 presents and discusses the model core of the DVPP that will be used in subsequent Tasks of this WP. The optimization model proposed includes three objective functions, which can be chosen depending on the business case followed by the DVPP manager. The model also comprises all technical constraints of the different units that can be part of a DVPP. Finally, network constraints including nodal power balance, and active power flow limits, are also presented.

Chapter 5 discusses the characterization of the different parameters that define the DVPP model proposed in Chapter 4. The Chapter focuses particularly on parameters that insert a level of uncertainty into the problem, such as stochastic sources, market prices and demand profiles. Finally, the Chapter also introduces the approach chosen to cope with such uncertainties, namely the *robust optimization*, which will be duly addressed in Task T5.2 and reported in Deliverable D5.2.

Chapter 6 presents and discusses a series of examples and case studies that serve to illustrate and validate the model core presented in Chapter 4. The case considered is a DVPP in a region of South Spain, which participates in the Spanish day-ahead and intra-day markets.

Finally, Chapter 7 draws conclusions, and outlines future work directions in the WP.

2 DVPPs in Electricity Markets

2.1 DVPP Definition and Context

The initial concept of VPP germinated from the need of tackling the relatively low competitiveness of the back then emerging nondispatchable renewable energy sources (ND-RESs) such as wind and solar generation when compared with large, dispatchable conventional generation such as hydro and thermal power plants. To increase this competitiveness is clearly essential to pave the way to an eventual mass integration of such renewable sources. The concept of VPP has naturally brought (and still does) an enormous interest during the last two decades, and a huge number of new assets, applications, scenarios and business cases have been studied, tested, and to some extent, implemented in practice. However, the main idea behind the VPP concept remains the same, i.e., to combine a number of independent assets in order to provide a flexible and economic solution to utilities that otherwise could not.

An alternative to the VPP concept that is rapidly gaining interest is the installation of electrochemical BESSs due to their capability to provide both active and reactive power regulation with very short time responses (down to several tens of milliseconds) [1]. Moreover, the advances in the BESS technology and their modularity imply a remarkable flexibility that allows the installation of BESSs of up to 100 MW and over 100 MWh such as the lithium-ion BESS installed in Hornsdale, Australia, by Tesla Inc. in 2017. The potential of BESSs to provide a large number of ancillary services and to mitigate the impact of the stochastic nature of ND-RESs, together with the gradual decrease in the price per MW and MWh, justify their current popularity as a solution to increase the competitiveness of ND-RESs.

However, the main limitations of BESSs that prevent their massive integration in the power grids are their still high installation (capital) costs, their relatively short life span (up to 7 years, or a few thousands of cycles), their intrinsic self-discharge (up to two percentual digits per day of their state of charge (SoC)), the limited availability of the materials required in their construction, and their negative environmental impact at the time of their disposal.

This project proposes a new concept called Dynamic Virtual Power Plant (DVPP), which comprises exclusively RESs of different nature (both dispatchable and non-dispatchable), as well as flexible demands. They are selected with the aim to ensure safe and reliable grid operation by offering their combined flexibility (e.g., fast ramp-up/down capability for frequency control), the possibility of balancing internally the stochastic RES fluctuations, and selling their aggregate generation output in the wholesale market [2].

The RES-based DVPP proposed in this work thus appears as a promising approach to overcome the limitations of BESSs listed above, and as a competitive solution to increase the viability of non-dispatchable RESs. Note that the additional cost involved in the setting-up of a DVPP from already installed RESs and flexible loads reduces to the installation costs of the deployment of the communication infrastructure required to coordinate all assets. Moreover, by optimally operating all assets, the increase of non-dispatchable RES competitiveness may even surpass the benefits achieved with BESS solutions.

The remainder of this Chapter provides details of the main business frameworks that are available for DVPPs, i.e., the wholesale electricity markets.

2.2 Electric Energy Markets Suitable for DVPPs

The most widespread strategy used in electric energy trading relies on power and energy markets. This is so since the late 1990s, where a transition from optimal control strategies took place worldwide at a remarkable pace [3].

Long-term electricity trading is mostly based on bilateral contracts, whereas short-term trading is generally based on competitive auctions or pools. The latter represents over 75% of the total energy traded [4].

In this stage of the project, the main focus is on the short-term markets, since they are the most relevant for our studies given their competitive nature. Short-term electricity trading usually spans a time window of 24 hours, and different pools take place prior to the power delivery. Two main groups of participants are present in such pools, namely generation (electricity producers) and demand (retailers and large consumers). According to the quantity traded, short-term electricity markets can be also categorized into *energy markets*, in which the market operator gives/receives payments according to the amount of energy supplied to/consumed from the network. Other markets are based on, e.g., the trading of power (mostly active, although reactive power-based markets are starting to become relevant).

This Section focuses on the energy market pools, namely the day-ahead and the intra-day energy markets. The main features of these markets, and the impact of the different DVPP components presented later in Chapter 4, are discussed below.

2.2.1 Day-Ahead Market

The first pool that is cleared in the electric energy trading covers the whole 24-hour window, split evenly in 24 periods of one hour. This pool is commonly referred to as day-ahead market (DAM), although other terms can be found such as spot market (Europe) and forward market (USA). In this market, which is usually cleared 12 hours before the first period of power delivery of the covered market window, generation and demand participants submit selling offers and purchasing bids, respectively, for each and every period of such a window. Such offers/bids consist in individual blocks characterized by an amount of energy generators/demands are willing to sell/buy, and the corresponding price. The market is then cleared by the market operator by constructing the so-called sale/purchase curves by sorting the offering/bidding blocks according to their corresponding prices, from lower to higher, and whose intersection determines the electricity price² and the total energy traded. This wholesale price is then used to remunerate/charge all generation/demand units whose offers/bids prices were lower/higher than or equal to the cleared one, i.e., the generating/demand units with the highest/lowest prices are excluded from the trading.

This is graphically illustrated in Figure 2-1, where generic sale (offer)/purchase (bid) curves are represented for a given period t of the market window. Note that such curves are, purposely, monotonically increasing and decreasing, respectively. The cheapest generation units, i.e., the ones at the leftmost side of the offer curve, usually correspond to the renewable energy sources, both stochastic (mostly wind and solar generation) and dispatchable (hydroelectric generation), and that are characterized by nearly zero supply cost. In rather particular occasions, prices offered by such sources can even be negative.

² Note that, if no network constraints are considered, a single price is determined by the DAM, whereas if transmission network limits and losses are included, several locational marginal prices may result from market clearance.

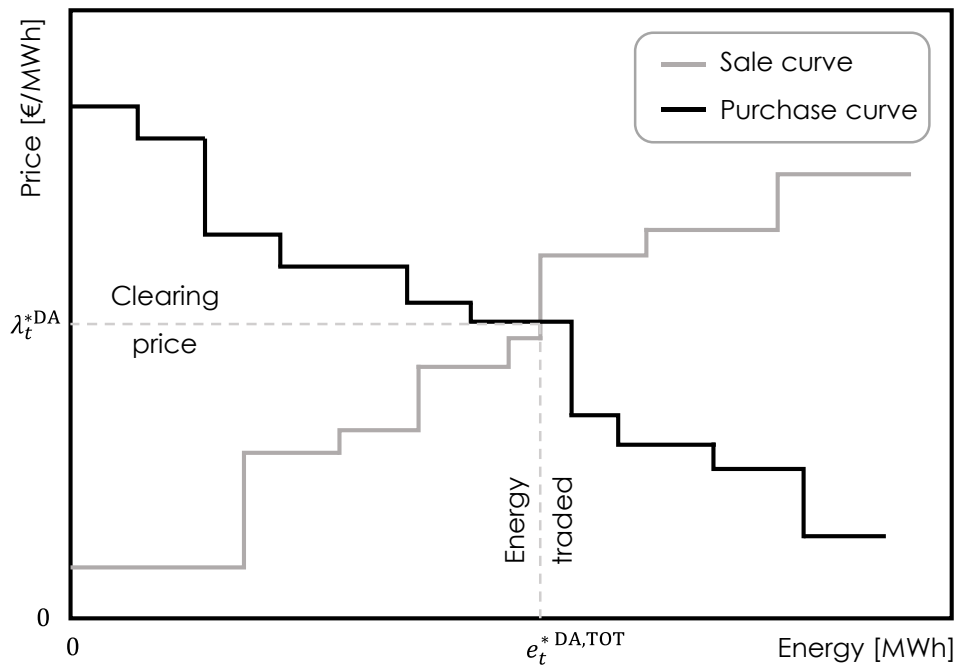


Figure 2-1 Example of sale/purchase curve used to clear each period of the day-ahead market.

Note that, as the share of *cheap* (renewable) generation units increase, the sale curve will be shifted to the right, thus increasing the amount of energy traded while decreasing its unit price. Conversely, if such share decreases, the offer curve is shifted do the left, thus decreasing the total traded energy, which is cleared at a higher price. This is illustrated in Figure 2-2.

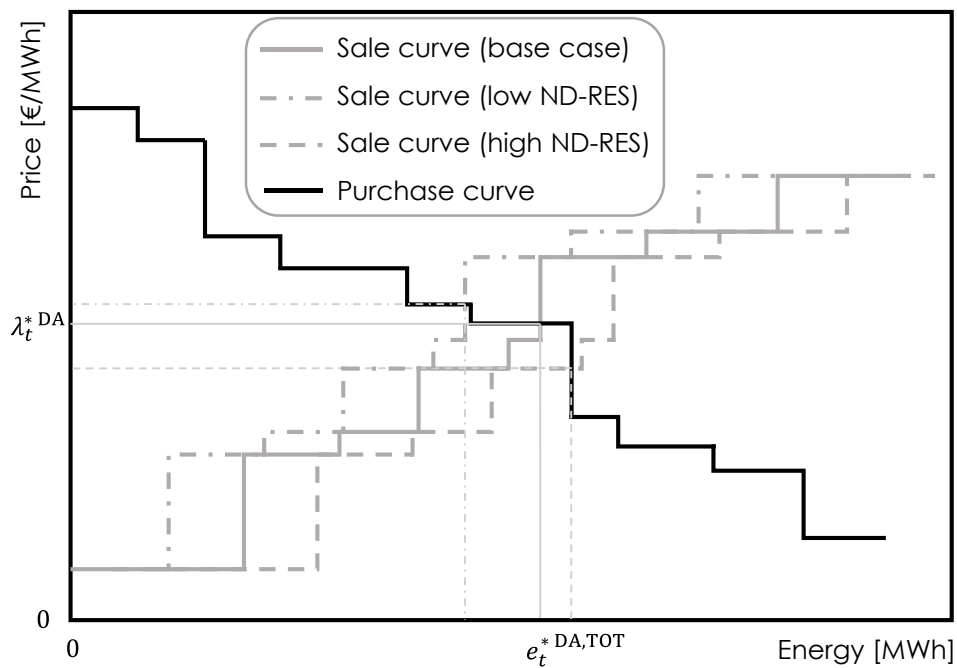


Figure 2-2 Example of market clearing results for different energy levels offered by renewable energy generation.

Another relevant feature of the DAM clearing process is that the cleared energy quantities and prices are not determined based on the actual realizations of the generation and consumption blocks offered/bid, but on their predicted values. In the past, where the vast majority of the electric energy was supplied by dispatchable power plants, such predictions were rather accurate at the time of offering/bidding prior the DAM clearing time (usually 12 hours before the start of the first delivery period). The main source of uncertainties was the load profile, for which good forecasting methods were available. However, with the advent of ND-RESs, DAM offer blocks show substantially higher uncertain profiles, even considering the highly sophisticated weather forecasting methods currently available. Such uncertainty aggravates as the forecast horizon increases, i.e., predictions for latest delivery periods (up to 35 hours in advance) are less accurate than those provided for the first periods (from 12 hours in advance) [5], [6].

However, despite the uncertainty that characterizes the predicted energy values of the offer blocks from ND-RESs, these are nevertheless prioritized over more accurate offer blocks from dispatchable generating units, and they are accepted first due to their low price (the so-called merit-order effect). However, one must carefully consider the implications of generation (and load) uncertainties in the clearing process with respect to their actual realizations. If during the period of energy delivery, there is more energy available from ND-RESs than predicted at the market clearance, the excess of energy needs to be curtailed, thus “wasting” cheap generation that could have been used to reduce the unit price of the energy. A potentially worse situation may occur in the opposite situation, i.e., when available ND-RES energy is lower than the amount cleared. In this case, two main solutions are available to maintain the power balance at all periods of the time horizon. On one hand, more expensive dispatchable units can be used to provide the deficit of energy, thus increasing the overall energy price. However, in the case where such energy cannot be delivered, e.g., if dispatchable units are not flexible enough (i.e., their ramp rates do not allow changing their power production fast enough), the alternative solution to maintain the power balance is to curtail load, which implies very high economic and societal costs.

For the reasons above, market operators apply different strategies of penalties to ND-RES owners if their forecasts are inaccurate, thus leading to mismatches between offered and generated energy. Moreover, the large number of incentives that were provided to ND-RES owners in the past are, for the most part, no longer available. ND-RESs are therefore compelled to participate in the DAM under the same market conditions as dispatchable generation units, and with the risk of penalization if forecasts are not accurate, placing ND-RESs at a disadvantage position.

To cope with the increasing number and volume of uncertainties in the DAM, both in offers and bids, operators have designed different market mechanisms that allow offer and bid units to (i) “update” their submitted energy volumes after the DAM has been cleared, and (ii) to compensate any unpredicted imbalance.

This set of solutions comprise additional market windows complementary to the DAM. In this regard, the most common one is the Intra-day Market (IDM) (see Section 2.2.2), which allows for updating the offer/bid blocks with more accurate weather/demand forecasts and is cleared after the DAM, up to several minutes before the start of the first delivery period of the time horizon, which uses a series of reserves, mainly from dispatchable units, scheduled in the DAM to compensate any unpredicted imbalance and is usually cleared a few minutes before the power delivery.

Note that other markets aside from DAM and IDM are available (see, e.g., the ancillary service markets described in Chapter 3). Most of such markets are based on the availability of certain

levels of power reserves that were adequately scheduled in advance. This is done in the DAM, where reserves and energy capacities are optimally cleared based on the offers/bids of generation/demand units. In this case, units need to submit two sets of capacity-price blocks, one for energy and another one for reserve. The optimal scheduling can be performed in two ways. One solution is to first schedule the traded energy as usual, and consecutively schedule the reserve capacity. The second strategy implies a simultaneous schedule of energy and reserve capacities. The latter is usually the preferred option, since it tends to minimize the overall costs from the operator's perspective without observing a significant increase in profits for generators.

In this WP, the optimization problem that provides the simultaneous scheduling of energy supply and reserve of the DVPP is formulated and implemented. Uncertainties of, e.g., intermittent generation, prices and load profiles are considered in the optimization problem by means of the Robust Optimization (RO) formulation that is described in Section 5.2, and whose main objective is to minimize the cost under the worst-case realization of the uncertain scenarios that will be addressed in the balancing stage.

The formulation of the simultaneous schedule of energy dispatch and reserves in the DAM under uncertainties by means of the RO from the system operator's perspective is conceptually summarized below [7].

Objective function:

Minimize *Day-ahead energy dispatch costs + Day-ahead reserve capacity costs*
 + *Worst-case energy redispatch (balancing stage) costs*

Constrains:

Power balance (day-ahead stage)

Reserve capacity determination

Energy and reserve capacity bounds

Power balance (worst-case scenario at balancing stage)

Network constrains (worst-case scenario at balancing stage)

Provided reserve determination (worst-case scenario at balancing stage)

Nonnegativity of pertinent variables

2.2.2 Intra-Day Market

We have seen in Section 2.2.1 how the *traditional* market structure of the DAM works in detriment to ND-RES owners despite their general prioritization over dispatchable generation in the pool. In the DAM, offers are submitted several hours before the delivery period based on predictions of available energy. Uncertainties in such predictions are not negligible, and cumulate over the delivery period. Risks and penalties associated to such uncertainties are thus the main aspects that limit the competitiveness of ND-RESs in the energy market.

Minimizing the uncertainties at the time of placing the offers is thus crucial for ND-RESs. This can be achieved by having a DAM clearing time closer to the actual delivery period, thus reducing the forecast horizon. However, this cannot be implemented in practice, as dispatchable generation units need to now the result of the schedule well in advance given their relatively low flexibility against changes in their generation. As an intermediate solution, *intra-day markets*, also referred to as *adjustment markets* have been developed and implemented. IDMs

are trading pools (usually more than one) that close between the DAM clearing time and the start of the delivery period (the last IDM usually clears 30 minutes or 1 hour before the delivery period). IDMs thus allow ND-REs and other market participants to “adjust” their offer/bid blocks according to updates on their predictions in weather/load profiles, which are characterized by higher certainty, and which usually imply higher profits with lower volatility.

IDMs are therefore essential for ND-REs, and thus, for the DVPP developed in the POSYTYF project, to increase their competitiveness and viability. Note that the formulation of the IDM as an optimization problem formally shares most of the characteristics of the DAM, and is thus not repeated here.

2.2.2.1 IDMs in Spain

To illustrate the participation of a DVPP in DAM and IDMs, the particular case of Spain is described below. The Spanish market has been considered due to the fact that it is particularly tailored to allow renewable energy sources to adjust, several times throughout the day, their energy volumes to be traded. Moreover, WP5 partners have deep knowledge of its market characteristics. WP5 industrial partners have also abundant historical data readily available to feed the DVPP model.

The Spanish market structure is illustrated in Figure 2-3. The market operator of the Spanish system (OMIE)³ is responsible for clearing the DAM and IDMs, which govern the day-to-day running of electricity provision and consumption in the Spanish system with some additional arrangements associated with ensuring reliability and secure operation of the energy system imposed by the Spanish transmission system operator, Red Eléctrica de España (REE)⁴ [8].

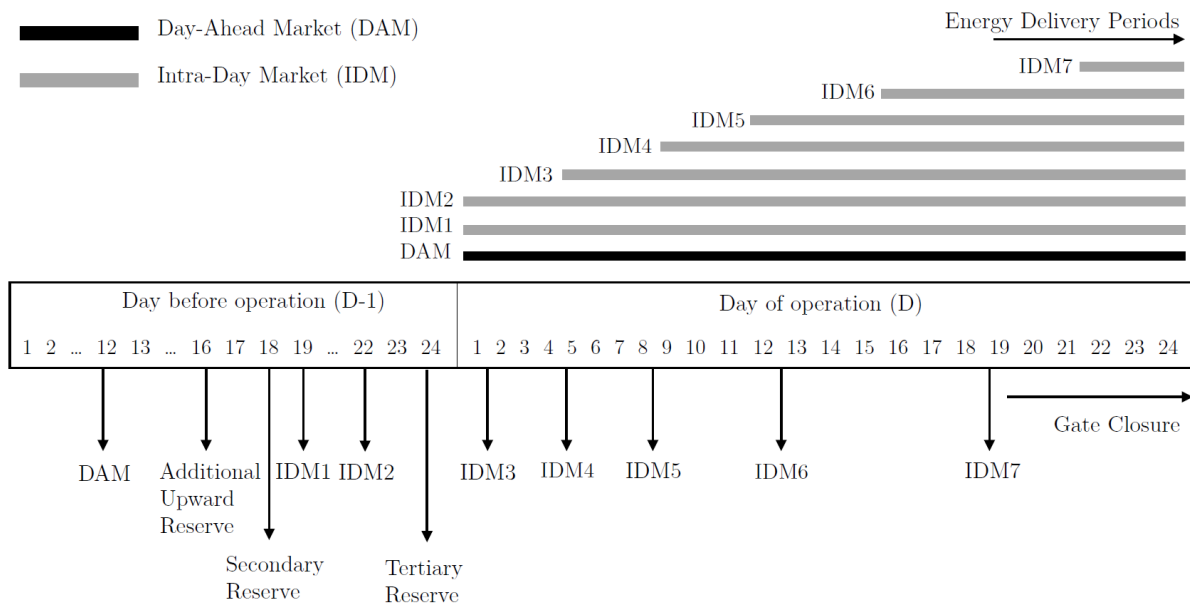


Figure 2-3 Sequence of Spanish Electric Energy Markets - adapted from [8].

After DAM clearance, secondary reserve market which is associated with automatic generation control is carried out (see Section 3.1.2). This is to ascertain the source of provision of the up and down regulation for the 24 hours of the operation day. Subsequently, IDMs are instantiated to adjust the DAM cleared bids and correct infeasible schedules. These

³ <https://www.omie.es/en>

⁴ <https://www.ree.es/en>

modifications or corrections can be due to unplanned shutdown of dispatchable sources of generation, changes in ND-RES outputs, demand changes and/or line faults. There are seven IDM sessions; the first and second cover 24 hours of the operation day while the remaining five sessions cover a receding subset of the 24 hours.

A consortium of generation and demand assets (i.e., a DVPP), participating in the Spanish energy market can thus capture the operational flexibility which the different energy market segments offer in order to maximize its revenue.

3 Ancillary Service Markets

Ancillary services are necessary control actions required to ensure the reliability and stability of the transmission system while balancing real time generation and demand, and they are gaining even more prominence as ND-RESs share increases. Depending on the system (country), some of these services can be procured competitively in so-called Ancillary Service Markets (ASMs), whereas some others are mandatory, and are imposed and supervised by the System Operator (SO).

Being system dependent, to provide a general taxonomy of the currently existing ancillary services which can be applicable in all systems is a convoluted matter. However, there is a general agreement on classifying, at a general level, the different services into three main families, depending on the *purpose* of such a service [9]. Such families are:

- i. *Frequency control services*, which, through active power support, are aimed at maintaining the active power balance between generation and consumption in the grid, thus keeping the system frequency as constant as possible around its reference value (50 Hz in Continental Europe);
- ii. *Voltage control services*, which, through reactive power support, help maintain voltage levels within acceptable bounds, thus ensuring secure and reliable operation; and
- iii. *Emergency services*, such as black-start services, required after severe events (e.g., blackouts).

A review of the current structure of different balancing markets in countries where such services are procured based on auctions or markets is developed in Task T1.3. In the remainder of this Section, a conceptual overview of each of the main ancillary service markets in which DVPPs can potentially participate is provided. When relevant, specific details of the market structure of each service in the Spanish system are also discussed. The reasons behind the selection of this system in particular are provided in Section 2.2.2.

3.1 Balancing Markets

Competitive auction markets employed in the procurement of the active power reserves used for frequency control services are known as balancing services. Depending on the response time of such services, they can be categorized as *Primary*, *Secondary* and *Tertiary Reserves*, for which different market auctions exist.

Reference [10] provides a recent review of the three European balancing markets above, and in which different categories have been developed with the aim to evaluate the “quality” of the markets in several European countries, as follows:

- access of emerging technologies to the balancing markets, where the entry barriers in terms of requirements such as the minimum bid size and aggregation possibilities are analyzed;
- measurement and prequalification requirements, where the goal is to understand whether such verification requirements act as a prohibitive barrier for new market participants;

- market segmentation and size, aimed at analyzing the health of the market based on several aspects such as the participants, capacities traded, diversity of technologies, etc.;
- transparency, where the detail and ease of access of the information provided by the system operator is studied; and
- upcoming changes of the current market design and legislation in terms of depth of change and timelines proposed.

The three balancing service markets are briefly summarized below.

3.1.1 Primary Reserve (FCR)

Also known as Frequency Containment Reserve (FCR), and is responsible for responding against power unbalances occurred in the system within few seconds after its detection, i.e., following the inertial response of synchronous generators (both conventional and *virtual*), preventing the frequency from deviating from its reference value. A key feature of conventional, fossil fuel-based power plants is their generally low ramping capability, which leads to slow primary response. RESs on the other hand show a much faster response times when required to change their power output as a response to changes in system load and/or generation [11]. This makes the RES-based DVPP proposed in the project a remarkably promising agent in this ASM. The Transmission System Operators (TSOs) from Austria, Belgium, the Netherlands, France, Germany, Switzerland, Slovenia and West Denmark currently procure their FCR in a common market.

3.1.1.1 FCR Market in Spain

Currently, there is no market structure developed for FCR in Spain. FCR is a non-remunerated service that is provided on a mandatory basis by every generator connected to the transmission network.

3.1.2 Secondary Reserve (FRR)

Also known as Frequency Restoration Reserve (FRR) and Automatic Generation control (AGC). Secondary ancillary service is used, automatically (aFRR) or manually (mFRR) after primary reserve has acted, and its main purpose is to bring the system frequency back to the reference value. To ensure stability, FRR time response is considerably slower than the FCR (usually from 30 seconds to 15 minutes) to avoid undesired *couplings* between regulators. For this reason, the system frequency is, for a substantial amount of time, different from the synchronous one [12], [13].

The power plants included in the FRR scheme are selected based on qualification tests, during which the units must be capable of deploying the required power, within a given response time, and for an unlimited period of time. Usually, hydroelectric and gas-fired combined-cycle power plants are the most suitable to provide this service, with nuclear and other thermal generators close behind. Regarding ND-RESs, which are based on stochastic sources, the response time requirement can be easily met (see Section 3.1.1 above). However, the requirement for providing the service for an unlimited time period is clearly limiting the possibility of ND-RESs to become FRR service providers by themselves.

Combining stochastic ND-RESs with dispatchable units such as hydro power plants, and with green storage systems such as pumped hydro and STUs in the form of a DVPP thus becomes

apparent. DVPPs would allow stochastic ND-RESs to compensate for their inherent power output variations, and meet the unlimited time provision requirement.

3.1.2.1 aFRR Market in Spain

The Spanish TSO, REE, is responsible for keeping the security of the Spanish power system [14], [15]. Unlike the energy markets (DAM and IDM), which are supervised by the Spanish Market Operator, OMIE, the balancing markets are settled by REE. In the case of power unbalances due to, e.g., equipment outages or sudden load increase, the FCR is the first one to act, and is responsible of bringing the frequency back to steady-state conditions. After a few tens of seconds, aFRR comes into play with the aim to bring back the frequency to its reference value, and maintain the area power interchange at the schedule point. The unit that wants to provide aFRR in the market needs to be qualified by REE. The main requirements are providing reserve for 15 min uninterruptedly in the resolution time of 1 hour and with a response time of 100 s.

The control underlying the Spanish aFRR, the AGC, is a hierarchical control, consisting of a central controller sending reference signals to zonal controllers. A zone comprises all qualified generating units of a generation company, which can be distributed across the overall system, and should not be understood as a specific geographic area. In real time, REE assigns the aFRR requirement for each zone of the Spanish system according to the cleared relative regulation band, and each zone sends commands to its units for providing reserve. Each zone has thus the responsibility for providing its determined reserve. Participants in the aFRR market receive the marginal price of the market (€/MW) and energy price (€/MWh) if REE activates aFRR in real-time.

We consider the DVPP is qualified for participation in the Secondary Reserve Market (SRM) as a balance responsible party. The current SRM market is a capacity market where individual generators bid capacity. The relation between up and down reserve is however guaranteed at a zonal level. Before the DAM is cleared, the DVPP owner can co-optimize the selling energy in the DAM, and the up/down capacity (single product and asymmetrical) and actual energy (very volatile and difficult to predict) in the SRM. At that stage, the DVPP owner only sends to the market operator the offers/bids of the share of energy related to the DAM at that time. Before the gate closure of the SRM, DVPP owner can optimize again up/down capacity of SRM considering the updated forecasts of uncertain parameters (e.g., SRM prices, and stochastic generation); the DAM bid/offer values that had already been assigned; and the first IDM session (IDM1). In the above optimization problem, it is possible to consider the IDM1 as an arbitrage opportunity because the gate closure time of IDM1 is very close to that of the SRM, and the predictions related to IDM1 in the gate closure of SRM are more accurate at that instant (compared to DAM). This way, the schedule of the DVPP is able to be updated in order to free up the capacity band.

The SRM has moderate liquidity (typical numbers are 700 MW for up and 500MW down reserve in 2012), and the payment can be higher than that of the DAM considering both capacity and energy. This is due to the reserve requirement in the system with high RES and the high demand during drought in some years. So, from the DVPP owner's perspective, it seems logical to co-optimize the SRM and DAM at a first stage to maximize the SRM benefit. In the SRM, the possibility of no settlement of the energy offer could also be considered. Thus, in this condition, REE only pays for capacity. This issue leads to the opportunity cost that DVPP owners should consider in the optimization problem (e.g., selling that energy in DAM or IDM). However, the DVPP elements can compensate, to some extent, the power surplus/shortage of each other so that the need for RES curtailment can be decreased. DVPP owner also needs to be ready to provide energy requirements if called by REE, since not satisfying the energy requirement or response criteria brings about penalization or dismissal from the market.

3.1.2.2 Application of PICASSO

The Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO) is the implementation project endorsed by all TSOs through the ENTSO-E Market Committee to establish the European platform for the exchange of balancing energy from aFRR.

The implementation of PICASSO will bring some modifications to the current SRM in Spain. The future SRM is executed every 15 minutes with market closing about 30 min before the instant of delivery. Balance service providers can bid different energy blocks with different prices instead of capacity. REE will assign the aFRR requirement according to the merit order of energy bids. This is different to the current scheme since in the current scheme all zones vary output according to relative size of the zonal regulation band, whereas in the future only those zones vary the output with energy bids at or below the aFRR requirement. Consequently, the bids will be cleared every 4 s (according to the activation of the ordered energy bids).

3.1.3 Tertiary Reserve (RR)

Also known as Replacement Reserve (RR). This is called if secondary service is exhausted, and generators (both spinning and non-spinning) connected to the transmission grid can provide this service. RR is activated manually when requested by the system. As the power unbalances can be negative or positive, the tertiary reserve is determined and activated for both the upward and downward regulation.

Generally, RR is slow, with small ramp-up rates and high start-up times. RR is thus provided generally by thermal power plants, which are notified with enough time whenever they will be required to change their power output.

Regarding the potential participation of the RES-based DVPP developed in this project in RR markets, same discussion as that provided in Section 3.1.2 for the FRR can be applied.

3.1.3.1 RR Market in Spain

The goal of the Tertiary Reserve Market (TRM) in Spain is to replace SRM if FRR cannot completely bring back frequency to its schedule value. Unlike FCR and aFRR, RR is manual, and it is mandatory.

There is no payment for capacity, and only there are energy payments at the marginal price (€/MWh) if the energy is required in real-time. Therefore, it seems logical that the DVPP owner does not consider this market before the DAM gate closure, as opposed to the co-optimization of SRM and DAM described in the previous Section. Thus, the DVPP only offers the remaining capacity after the second IDM session (IDM2) in the TRM. The DVPP owner should offer his remaining resources before the TRM gate closure to provide separate up and down reserve (without payment) and the actual energy of the TRM. As the gate closure of TRM is closer to real-time, the RES forecasts are more accurate, and if the market is called, the revenue of DVPP is characterized by a small degree of uncertainties.

3.2 Reactive Power / Voltage Control

Voltage is controlled in the grid by deploying reactive power resources. Reactive power/voltage control can be a mandatory or supplementary service. In case of mandatory services, service providers have to fulfil compulsory connections requirements according to the

voltage level at their connection point and the provider's capacity. The supplementary services refer to non-mandatory, additional reactive power/voltage control services.

Most countries in the EU make use of a mandatory scheme for reactive power/voltage control service⁵. In some countries, this service is remunerated and in others, it is not. Certain Distributed Energy Resources (DERs), depending on the size, have to provide voltage control as well.

3.2.1.1 Voltage Control Market in Spain

Currently, there is no market structure developed for voltage control in Spain. Voltage control is a non-remunerated service that is provided on a mandatory basis by every generator connected to the transmission network.

A partially obligatory, partially subject to payment based on performance evaluation scheme was proposed for the provision of voltage control service [16], [17]. According to this proposal, after the mandatory requirement, remaining capacity is remunerated at a fixed regulated price set by the transmission system operator. Providers of voltage control ancillary service are generally generating units greater than 30MW capacity of rated power and qualified consumers greater than 15MW. These generating units are directly connected to the transmission grid (i.e. 400kV and 220kV levels). Demands of this service are qualified consumers and distribution companies. In Spain, there are four offers differentiated by the power factor that represents them, as follows:

- A1 - valid for peak and plateau hours;
- A2 - Valid for peak hours;
- B1 - valid for valley and plateau hours; and
- B2 - valid for valley hours.

3.3 Fast Frequency Response

Fast frequency response (FFR) is a service aimed at providing fast active power responses to frequency variations in the time frame following the inertial response. Activation time is thus within a couple of seconds, being faster than the *conventional* FCR discussed in Section 3.1.1. Given their different time frames, FFR and FCR offers can be efficiently combined.

This service attempts to partially offset the problems caused by low system-inertia levels. Lower system-inertia levels affect the initial rate-of-change of frequency after an active power unbalance. For instance, in the Nordic power system, FFR needs are estimated according to the system inertia levels (there are higher needs during spring and summer and at night, but this also depends on the hydrological year). Note however that FFR is not equivalent to inertial response.

FFR assignment can be imposed by grid codes, through competitive auctions or through market sessions. For instance, Spanish operation procedures consider a voluntary inertia emulation by electric power modules of type B and C. HydroQuebec requires an inertia emulation to all wind farms connected to the transmission grid with a capacity larger than 10 MW.

⁵ See <https://doi.org/10.3390/en13040917>

In Ireland, UK and Italy, competitive auctions have been or will be used to assign the FFR to bidders. For the Enhanced Frequency Response in UK, competitive auctions have been held and service is remunerated according to the offered availability price, modified by performance-related penalties. A similar scheme has been used for Phase 1 of Stability Pathfinder in UK. Terna has also proposed an auction-based assignment with a price cap. Finally, competitive auctions have been foreseen in Ireland to determine the price, but regulated tariffs have been applied initially due to lack of market competition. Remuneration is thus done according to the regulated tariffs modified by a set of scalars.

Market-based solutions have been or will be implemented in Finland and Denmark. In Denmark, monthly capacity auctions for FFR are run with a remuneration according to pay-as-cleared. In the future, a daily market with hourly bids will be implemented with a pay-as-cleared remuneration. In Finland, a daily market with hourly bids has been implemented with a pay-as-cleared remuneration.

4 DVPP Objective Functions and Components – Description, Characterization and Modeling

A proper formulation of the DVPP model that is being developed in this task T5.1 is crucial for an adequate analysis in subsequent tasks within this WP. This model should be detailed enough to cover all relevant aspects that can have an impact on the optimal operation and configuration of a DVPP that participates in the markets listed in Chapters 2 and 3. However, a compromise of such level of detail must be met in order to prevent the optimization algorithm from becoming too cumbersome and computationally too demanding. The model should also be able to represent all key components of the DVPP, as well as all functionalities and scenarios identified, and for a set of business models that will be defined.

To ensure the tractability of the problem of formulating the DVPP model, a modular design of the model itself is being developed. In this regard, the first main objective is to develop the **core** of the model which will represent all DVPP components, and a set of key features that is representative of the first group of scenarios that will be considered for analysis. Then, the modular structure of the model would allow the subsequent implementation of complementary features and functionalities to cover all aspects to be studied within this WP.

The model core will thus include the models of the DVPP components such as dispatchable (D-RES) and nondispatchable (ND-RES) renewable energy sources; flexible demands including interruptible loads, "continuous" regulating loads (e.g., thermostatically controlled loads) and electric-vehicle (EV) fleets (grid-to-vehicle, or G2V); and conventional, nonelectrochemical energy storage systems (ESSs) such as pumped hydroelectric energy storage (PHES) and solar-thermal units (STU) with storage capability.

The model core will consider one main business case for the DVPP, namely the so-called Power Generation Business, and whose objective function is to maximize the profit from the participation of the DVPP in the DAM and IDM, and the SRM. In future stages of the development, other components could be included such as vehicle-to-grid (V2G) EV fleets, or other converter-interfaced storage technologies such as flywheel-, ultracapacitor- or compressed air-based solutions. Other market windows such as the remaining balancing markets (FCR and mFRR), the voltage control market, and FFR market would also be considered.

Given the nature of the business case considered, the model core will thus cover active power transfers between the DVPP and the main grid, modeling the network power flow constraints with the well-known DC-optimal power flow (DC-OPF). Future stages of the development will include network constraints also for reactive power transfers (AC-OPF).

4.1 Notation

This section presents and describes the notation used to formulate the DVPP model proposed in this deliverable. In the remainder of this document, uppercase Latin letters indicate *parameters*; lowercase Latin letters represent indexes of sets when used as subscripts, and variables when they are not; and script Latin letters represent sets of, e.g., buses, specific devices, lines and time periods. Uppercase and lowercase Greek letters are seldom used for very specific sets, parameters and variables based on their commonly-used notation (e.g., δ for angles, Δ for increments), and they are duly described when required.

4.1.1 Indexes and Sets

$b \in \mathcal{B}/\mathcal{B}_m$	Network buses / network buses connected to the main grid
$c \in \mathcal{C}/\mathcal{C}_b$	Conventional D-RESs / D-RESs connected to bus b
$d \in \mathcal{D}/\mathcal{D}_b$	Demands / demands connected to bus b
$i(\ell)/j(\ell)$	Sending- / receiving-end bus of line ℓ
$k \in \mathcal{K}$	IDM session
$\ell \in \mathcal{L}/\mathcal{L}_b/\mathcal{L}_m$	Network lines / network lines connected to bus b/m
$p \in \mathcal{P}$	Load profiles
$r \in \mathcal{R}/\mathcal{R}_b$	Stochastic ND-RESs / ND-RESs connected to bus b
$s \in \mathcal{S}/\mathcal{S}_b$	ESSs / ESSs connected to bus b
$t \in \mathcal{T}$	Time periods
$v, v' \in \mathcal{V}$	SRM calls on condition by DVPP operator
$\theta \in \Theta/\Theta_b$	STUs / STUs connected to bus b
$\psi \in \Psi$	Set of all D-RESs, ND-RESs, ESSs, demands and STUs
$\Xi^{\text{DA}}/\Xi^{\text{ID}}/\Xi^{\text{SR}}$	Set of decision variables of DAM / IDM / SRM

4.1.2 Parameters

C_c^0/C_c^1	Shut-down / start-up cost of D-RES c	[€]
C_c^V	Variable production cost of D-RES c	[€/MWh]
DO_c/UP_c	Number of periods D-RES c has been offline / online prior to the first period	[hour]
DT_c/UT_c	Minimum down / up time of DRES c	[hour]
$N_c^{\text{off}}/N_c^{\text{on}}$	Number of initial periods during which D-RES c must be offline / online	[hour]

$\bar{P}_c / \underline{P}_c$	Maximum / minimum power production of D-RES c	[MW]
$\bar{R}_c / \underline{R}_c$	Up / down ramping limit of D-RES c	[MW/h]
R_c^1 / R_c^0	Start-up / shut-down ramping limit of D-RES c	[MW/h]
$\bar{R}_c^{SR} / \underline{R}_c^{SR}$	Up / down ramping limit of D-RES c	[MW/min]
$U_{c,0}$	Initial commitment status of D-RES c (1 if it is generating electricity, 0 otherwise)	[0/1]
$C_{d,p}$	Cost of load profile p of demand d	[€]
E_d	Minimum energy consumption of demand d throughout the planning horizon	[MWh]
$\underline{P}_{d,t}$	Lower bound of the power consumption of demand d in time period t	[MW]
$\bar{P}_{d,t}$	Upper bound of the power consumption of demand d in time period t	[MW]
$P_{d,p,t}$	Maximum hourly consumption of profile p of demands	[MW]
$\bar{R}_d / \underline{R}_d$	Up / down ramping limit of demand d	[MW/h]
$\bar{R}_d^{SR} / \underline{R}_d^{SR}$	SRM up / down ramping limit of demand d	[MW/min]
C_r	Operation and maintenance costs of ND-RESs	[€]
$\hat{P}_{r,t}$	Available production level of ND-RES r in time period t	[MW]
$\underline{P}_{r,t}$	Minimum power production of ND-RES r in time period t	[MW]
$\bar{R}_r^{SR} / \underline{R}_r^{SR}$	SRM up / down ramping limit of ND-RES r	[MW/min]
C_s	Total BESS unit cost, including installation and expected operational costs	[€]
$\bar{E}_{s,t}$	Energy capacity of ESS s	[MWh]
$\bar{E}_{s,t} / \underline{E}_{s,t}$	Upper / lower bound of the energy stored in ESS s in time period t	[MWh]
M_s	Slope of the linear approximation of the expected life of BESS s as a function of the cycles	[-]
$\bar{P}_s^+ / \underline{P}_s^+$	Upper / lower bound of charging capacity of ESS s	[MW]
$\bar{P}_s^- / \underline{P}_s^-$	Upper / lower bound of discharging capacity of ESS s	[MW]
$\bar{R}_s^{SR} / \underline{R}_s^{SR}$	SRM up / down ramping limit of ESS s	[MW/min]
$\bar{\alpha}_s / \underline{\alpha}_s$	Upper / lower bound multiplier of ESS s at last period in schedule	[-]
γ_s	Self-discharge rate of BESS s over a 24-hour period	[%]
η_s^+ / η_s^-	Charging / discharging efficiency of ESS s	[%]

DO_{θ}/UP_{θ}	Number of periods STU θ has been offline / online prior to the first period	[hour]
DT_{θ}/UT_{θ}	Minimum down/up time of STU θ	[hour]
K_{θ}	Output multiplier at startup of STU θ	[-]
$N_{\theta}^{\text{off}}/N_{\theta}^{\text{on}}$	Number of initial periods during which STU θ must be offline / online	[hour]
$\bar{P}_{\theta}/\underline{P}_{\theta}$	Maximum / minimum power production of STU θ	[MW]
$\bar{P}_{\theta}^{+}/\underline{P}_{\theta}^{+}$	Upper / lower bound of charging capacity of STU θ thermal storage	[MW]
$\bar{P}_{\theta}^{-}/\underline{P}_{\theta}^{-}$	Upper/ lower bound of discharging capacity of STU θ thermal storage	[MW]
P_{θ}^N	Power thresholds delimiting the linear segments $N \in \{1,2,3,4\}$ for the power conversion in the power block of STU θ	[MW]
$P_{\theta,n}^{\text{PB}}$	Bound defined in each piece-wise linear function n of the power block of STU θ	[MW]
$\hat{P}_{\theta,t}$	Available production level of STU θ in time period t	[MW]
$\bar{R}_{\theta}^{\text{SR}}/\underline{R}_{\theta}^{\text{SR}}$	SRM up / down ramping limit of STU θ	[MW/min]
$\eta_{\theta}^{+}/\eta_{\theta}^{-}$	Charging / discharging efficiency of STU θ thermal storage	[%]
$\eta_{\theta,n}$	Conversion factor between thermal and electrical power in each piece-wise function n of the power block of STU θ	[%]

B_{ℓ}	Susceptance of line ℓ	$[\Omega^{-1}]$
$\bar{P}_{\ell}$	Capacity of network line ℓ	[MW]
$\bar{P}_b^m$	Maximum power that can be traded with the main grid at bus b	[MW]
S^B	System power base	[MVA]
X_{ℓ}	Reactance of network line ℓ	$[\Omega]$

F^{SR}	Maximum SRM calls on duration time divided by the duration of a whole period	[-]
T	Last period of schedule	[-]
T^{SR}	Required time for SRM action	[min]
Δt	Duration of time periods	[h], [min]
$\lambda_{k,t}^{\text{ID}}$	Price of IDM session k in time period t	[€/MWh]
$\lambda_{k,t}^{\text{DA}}$	Price of DAM in time period t	[€/MWh]
$\lambda_{k,t}^{\text{SR},\uparrow}/\lambda_{k,t}^{\text{SR},\downarrow}$	Price of up / down SRM in time period t	[€/MW]

4.1.3 Variables

4.1.3.1 Continuous Variables

$c_{c,t}^1/c_{c,t}^0$	Auxiliary variable used to linearize the start-up cost of D-RES c in time period t	[€]
$p_{c,t}$	Active power generation of D-RES c in time period t	[MW]
$r_{v,c,t}^{SR,\uparrow}/r_{v,c,t}^{SR,\downarrow}$	Up / down aFRR provided by D-RESs in time period t of SRM for calls on condition v by DVPP operator	[MW]
$p_{d,t}$	Active power consumption of demand d in time period t	[MW]
$r_{v,d,t}^{SR,\uparrow}/r_{v,d,t}^{SR,\downarrow}$	Up / down aFRR provided by demand d in time period t of SRM for calls on condition v by DVPP operator	[MW]
$p_{r,t}$	Active power generation of ND-RES r in time period t	[MW]
$r_{v,r,t}^{SR,\uparrow}/r_{v,r,t}^{SR,\downarrow}$	Up / down aFRR provided by ND-RES r in time period t of SRM for calls on condition v by DVPP operator	[MW]
c_s^{deg}	Degradation cost per cycle of ESS s	[€]
$e_{s,t}$	Energy stored in ESS s in time period t	[MWh]
$p_{s,t}$	Active power output of ESS s in time period t (positive if discharging)	[MW]
$p_{s,t}^+/p_{s,t}^-$	Charging / discharging power level of ESS s in time period t	[MW]
$r_{v,s,t}^{SR,\uparrow}/r_{v,s,t}^{SR,\downarrow}$	Final up / down aFRR provided by ESS s in time period t of SRM for calls on condition v by DVPP operator	[MW]
$r_{v,s,t}^{SR,+,\uparrow}/r_{v,s,t}^{SR,+,\downarrow}$	Up / down aFRR provided by ESS s when in charging state in time period t of SRM for calls on condition v by DVPP operator	[MW]
$r_{v,s,t}^{SR,-,\uparrow}/r_{v,s,t}^{SR,-,\downarrow}$	Up / down aFRR provided by ESS s when in discharging state in time period t of SRM for calls on condition v by DVPP operator	[MW]
$u_{s,t}$	Binary variable used to prevent the simultaneous charging and discharging of ESS s in time period t	[–]
$\sigma_s^{SR,\uparrow}/\sigma_s^{SR,\downarrow}$	Share of ESS s energy capacity allocated to provide up / down aFRR	[%]
$e_{\theta,t}$	Energy stored in the thermal storage of STU θ in time period t	[MWh]
$p_{\theta,t}$	Active power output of STU θ in time period t	[MW]
$p_{\theta,t}^{\text{PB}}$	Active power sent to the power block of STU θ in time period t	[MW]
$p_{\theta,t}^{\text{SF}}$	Active power output of the solar field of STU θ in time period t	[MW]

$p_{\theta,t}^+ / p_{\theta,t}^-$	Charging / discharging power level of STU θ thermal storage in time period t	[MW]
$r_{v,\theta,t}^{SR,\uparrow} / r_{v,\theta,t}^{SR,\downarrow}$	Final up / down aFRR provided by STU θ in time period t of SRM for calls on condition v by DVPP operator	[MW]
$r_{v,\theta,t}^{SR,+,\uparrow} / r_{v,\theta,t}^{SR,+,\downarrow}$	Up / down aFRR provided by STU θ when in charging state in time period t of SRM for calls on condition v by DVPP operator	[MW]
$r_{v,\theta,t}^{SR,-,\uparrow} / r_{v,\theta,t}^{SR,-,\downarrow}$	Up / down aFRR provided by STU θ when in discharging state in time period t of SRM for calls on condition v by DVPP operator	[MW]
$x_{\theta,t,n}$	Non-negative continuous variable to write SOS-2 constraints for STU θ in time period t	[-]

$p_{\ell,t}$	Active power flow through line ℓ in time period t	[MW]
$p_{v,\ell,t}$	Active power flow through line ℓ in time period t for calls on condition v by DVPP operator	[MW]
$\delta_{b,t}$	Voltage angle at bus b in time period t	[rad]
$\delta_{v,b,t}$	Voltage angle at bus b in time period t for calls on condition by DVPP operator	[rad]

$p_{b,t}^m$	Active power scheduled to be bought from (+)/sold to (-) the DAM and IDM markets at bus b in time period t	[MW]
$r_{b,t}^{SR,\uparrow} / r_{b,t}^{SR,\downarrow}$	Up / down aFRR provided by DVPP at main grid buses in time period t	[MW]
$r_t^{SR,\uparrow} / r_t^{SR,\downarrow}$	Total up / down aFRR traded in the SRM in time period t	[MW]
$r_{v,b,t}^{SR}$	SR provided by DVPP at main grid buses in time period t for calls on condition v by DVPP operator	[MW]
p_t^{DA}	Total power traded in the DAM in time period t	[MW]
p_t^{ID}	Total power traded in the IDM in time period t	[MW]

4.1.3.2 Binary Variables

$u_{c,t}$	Binary variable that is 1 if D-RES c is generating electricity in time period t , and 0 otherwise.	[0/1]
$u_{v,c,t}^{SR}$	Binary variable used to prevent the simultaneous provision of up and down aFRR by D-RES c in time period t for calls on condition v by DVPP operator	[0/1]
$v_{c,t}^0 / v_{c,t}^1$	Binary variable that is 1 if D-RES c is shut down / started up in time period t , and 0 otherwise.	[0/1]

$u_{d,p}$	Binary variable to select profile p of demand d	[0/1]
$u_{v,d,t}^{SR}$	Binary variable used to prevent the simultaneous provision of up and down aFRR by demand d in time period t for calls on condition v by DVPP operator	[0/1]

$u_{v,r,t}$	Binary variable to turn off the ND-RES r in time period t for calls on condition v by DVPP operator	[0/1]
$u_{v,r,t}^{SR}$	Binary variable used to prevent the simultaneous provision of up and down aFRR by ND-RES r in time period t for calls on condition v by DVPP operator	[0/1]
$u_{s,t}$	Binary variable used to prevent the simultaneous charging and discharging of ESS s in time period t	[0/1]
$u_{v,s,t}^{SR,+} / u_{v,s,t}^{SR,-}$	Binary variable used to prevent the simultaneous provision of up and down aFRR by ESS s in time period t for calls on condition v by DVPP operator for charging / discharging state	[0/1]
$u_{\theta,t}^+$	Binary variable that is 1 if STU θ thermal storage is charging in time period t , and 0 otherwise.	[0/1]
$u_{v,\theta,t}^{SR,+} / u_{v,\theta,t}^{SR,-}$	Binary variable used to prevent the simultaneous provision of up and down aFRR by STU θ in time period t for calls on condition v by DVPP operator for charging / discharging state	[0/1]
$v_{\theta,t}^1$	Binary variable that is 1 if power block of STU θ is shut down / started up in time period t , and 0 otherwise.	[0/1]
$u_{v,\ell,t}^{SR}$	Binary variable used to prevent the simultaneous up and down aFRR flow of line ℓ in time period t for calls on condition v by DVPP operator	[0/1]
$y_{\theta,t,n}$	Binary variable to write the SOS-2 constraints	[0/1]

4.2 DVPP Objective Functions – Business Models

The objective functions of the DVPP that wants to participate in a sequence of markets (Power Generation Business), including DAM, SRM, and IDMs, are formalized in this section.

4.2.1 DAM Objective Function

The DVPP objective function (4.1) in the DAM maximizes the benefits that the DVPP can obtain by selling energy in the DAM and selling up/down reserve in the SRM minus costs. The costs include the operation cost of D-RES, maintenance and operation costs of ND-RES, the BESS degradation cost⁶, and the cost of selecting a particular load profile. The DVPP offers the energy obtained by (4.1) before the gate closure of the DAM, but the value of up/down SR is not offered in the DAM and will be reoptimized before the SRM gate closure.

⁶ Note that BESSs are not part of the DVPP presented in this document. However, to have a *model core* general enough to be able to simulate all possible scenarios, BESS characteristics are also included, and can be enabled/disabled in the model when required.

$$\begin{aligned} \max_{\varepsilon^{\text{DA}}} \sum_{t \in \mathcal{T}} & \left[\lambda_t^{\text{DA}} p_t^{\text{DA}} \Delta t + \lambda_t^{\text{SR}, \uparrow} r_t^{\text{SR}, \uparrow} + \lambda_t^{\text{SR}, \downarrow} r_t^{\text{SR}, \downarrow} - \sum_{c \in \mathcal{C}} (C_c^V(p_{c,t}^{\text{DA}}) \Delta t + c_{c,t}^0 + c_{c,t}^1) \right. \\ & \left. - \sum_{r \in \mathcal{R}} (C_r^R(p_{r,t}^{\text{DA}}) \Delta t) \right] - \sum_{s \in \mathcal{S}} c_s^{\text{deg}} - \sum_{d \in \mathcal{D}} \sum_{p \in \mathcal{P}} C_{d,p} u_{d,p} \end{aligned} \quad (4.1)$$

4.2.2 SRM Objective Function

Before the SRM gate closure, the DVPP maximizes the benefits of selling up/down reserve in the SRM and energy in the first IDM (IDM1). The costs are the rescheduling operation costs of D-RES and ND-RES in the IDM1 and the BESS degradation cost (if considered). The objective function (4.2) provides the possibility to consider the arbitrage opportunity between the SRM and IDM1. The DVPP offers the up/down reserve obtained by (4.2) before the gate closure of the SRM, but the value related to IDM1 energy is not offered before the SRM gate closure and will be kept for the IDM1. In (4.2), we only consider the IDM1 and ignore other sessions. This is due to the fact that IDM1 gate-closer is closer to the SRM rather than other sessions, which enhances the possibility for more accurate forecast. Besides, the IDM1 has more liquidity compared to others.

$$\begin{aligned} \max_{\varepsilon^{\text{SR}}} \sum_{t \in \mathcal{T}} & \left[\lambda_t^{\text{SR}, \uparrow} r_t^{\text{SR}, \uparrow} + \lambda_t^{\text{SR}, \downarrow} r_t^{\text{SR}, \downarrow} + \lambda_{(k=1),t}^{\text{ID}} p_{(k=1),t}^{\text{ID}} \Delta t - \sum_{c \in \mathcal{C}} (C_c^V(p_{(k=1),c,t}^{\text{ID}}) \Delta t + c_{c,t}^0 + c_{c,t}^1) \right. \\ & \left. - \sum_{r \in \mathcal{R}} (C_r^R(p_{(k=1),r,t}^{\text{ID}}) \Delta t) \right] - \sum_{s \in \mathcal{S}} c_s^{\text{deg}} \end{aligned} \quad (4.2)$$

4.2.3 IDMs Objective Functions

The objective function of the DVPP for each of the seven sessions of Spanish IDM is calculated based on (4.3). In each IDM session, the DVPP maximizes the benefits of selling energy minus the D-RES and ND-RES operations costs and the battery degradation cost.

$$\max_{\varepsilon_k^{\text{ID}}} \sum_{t \geq \tau} \left[\lambda_{k,t}^{\text{ID}} p_{k,t}^{\text{ID}} \Delta t - \sum_{c \in \mathcal{C}} (C_c^V(p_{k,c,t}^{\text{ID}}) \Delta t + c_{k,c,t}^0 + c_{k,c,t}^1) - \sum_{r \in \mathcal{R}} (C_r^R(p_{k,r,t}^{\text{ID}}) \Delta t) \right] - \sum_{s \in \mathcal{S}} c_s^{\text{deg}}, \quad \forall k \in \mathcal{K} \quad (4.3)$$

4.3 Network

Each and every asset that composes the DVPP is necessarily connected to the main power grid at a specific bus or node. The set of buses to which DVPP components are connected, and the lines that link such buses among them and with the grid compose an electrical network, and as such, needs to meet specific constraints related to power balance (buses) and power flows (lines). This section presents the equations that model the network constraints, and discusses the assumptions made in their formulation.

Such equations represent constraints of the optimization algorithm that is being developed in this Task. For convenience in the implementation in the optimization software tools, and to facilitate the retrieval of the solution of the problem, all constraints are formulated as either equalities or lower-than inequalities. This rationale applies also to the model of the DVPP assets described in subsequent Sections. A brief description of each equation is also provided.

4.3.1 DAM Supply-Demand Balancing Constraints

Constraints (4.4) and (4.5) enforce the supply-demand balancing for the DVPP units considering both energy and up/down aFRR for the main grid buses and other buses, respectively. We consider the DVPP as a balance responsible party that can asymmetrically provide up/down SRM. No matter the TSO calls for the up or down aFRR, the DVPP can exploit its units' up or down aFRR. We consider three states for each of the constraints (4.4) and (4.5). When $v = 0$, the supply-demand balancing constraints are only held for the DAM power. Alternatively, if $v = 1$ or $v = 2$, the supply-demand balancing constraints are held for the DAM power and up SRM, or power and down SRM, respectively. The three states above keep the power balance equations for all possible SRM situations in real-time (i.e., the aFRR not called on, and up or/and down reserve called on). The goal is not to schedule the units according to the actual realization of the reserve, as it is impossible to predict the aFRR activation sign and value accurately. Instead, the logic behind these states is to assign power and aFRR boundaries (according to delivery time possibilities) for offering the optimal amounts of energy and reserve to the market. Constraint (4.6) enforces the up/down reserve of DVPP units to be zero for state $v = 0$. Constraints (4.7)-(4.9) assign the aFRR offered by the main buses to the market equals zero, the up aFRR, and down aFRR for the states $v = 0, 1$, and 2 , respectively.

$$\begin{aligned} & \sum_{c \in \mathcal{C}_b} (p_{c,t} + r_{v,c,t}^{\text{SR},\uparrow} - r_{v,c,t}^{\text{SR},\downarrow}) + \sum_{r \in \mathcal{R}_b} (p_{r,t} + r_{v,r,t}^{\text{SR},\uparrow} - r_{v,r,t}^{\text{SR},\downarrow}) + \sum_{s \in \mathcal{S}_b} (p_{s,t} + r_{v,s,t}^{\text{SR},\uparrow} - r_{v,s,t}^{\text{SR},\downarrow}) \\ & + \sum_{\theta \in \Theta_b} (p_{\theta,t} + r_{v,\theta,t}^{\text{SR},\uparrow} - r_{v,\theta,t}^{\text{SR},\downarrow}) - \sum_{\ell | i(\ell)=b} p_{v,\ell,t} + \sum_{\ell | j(\ell)=b} p_{v,\ell,t} \\ & = p_{b,t} + r_{v,b,t}^{\text{SR}} + \sum_{d \in \mathcal{D}_b} (p_{d,t} - r_{v,d,t}^{\text{SR},\uparrow} + r_{v,d,t}^{\text{SR},\downarrow}), \quad \forall v \in \mathcal{V}, \forall b \in \mathcal{B}_m, \forall t \in \mathcal{T} \end{aligned} \quad (4.4)$$

$$\begin{aligned} & \sum_{c \in \mathcal{C}_b} (p_{c,t} + r_{v,c,t}^{\text{SR},\uparrow} - r_{v,c,t}^{\text{SR},\downarrow}) + \sum_{r \in \mathcal{R}_b} (p_{r,t} + r_{v,r,t}^{\text{SR},\uparrow} - r_{v,r,t}^{\text{SR},\downarrow}) + \sum_{s \in \mathcal{S}_b} (p_{s,t} + r_{v,s,t}^{\text{SR},\uparrow} - r_{v,s,t}^{\text{SR},\downarrow}) \\ & + \sum_{\theta \in \Theta_b} (p_{\theta,t} + r_{v,\theta,t}^{\text{SR},\uparrow} - r_{v,\theta,t}^{\text{SR},\downarrow}) - \sum_{\ell | i(\ell)=b} p_{v,\ell,t} + \sum_{\ell | j(\ell)=b} p_{v,\ell,t} \\ & = \sum_{d \in \mathcal{D}_b} (p_{d,t} - r_{v,d,t}^{\text{SR},\uparrow} + r_{v,d,t}^{\text{SR},\downarrow}), \quad \forall v \in \mathcal{V}, \forall b \in \mathcal{B}/\mathcal{B}_m, \forall t \in \mathcal{T} \end{aligned} \quad (4.5)$$

$$r_{(v=0),\psi,t}^{\text{SR},\uparrow} = r_{(v=0),\psi,t}^{\text{SR},\downarrow} = 0, \quad \forall \psi \in \Psi, \forall t \in \mathcal{T} \quad (4.6)$$

$$r_{(v=0),b,t}^{\text{SR}} = 0, \quad \forall b \in \mathcal{B}_m, \forall t \in \mathcal{T} \quad (4.7)$$

$$r_{(v=1),b,t}^{\text{SR}} = r_{b,t}^{\text{SR},\uparrow}, \quad \forall b \in \mathcal{B}_m, \forall t \in \mathcal{T} \quad (4.8)$$

$$r_{(v=2),b,t}^{\text{SR}} = r_{b,t}^{\text{SR},\downarrow}, \quad \forall b \in \mathcal{B}_m, \forall t \in \mathcal{T} \quad (4.9)$$

4.3.2 SRM Supply-Demand Balancing Constraints

The constraints (4.10)-(4.12) are very similar to (4.4)-(4.9). The difference is that the power related to units and selling power by main buses in the DAM are fixed at their obtained values from solving the DAM optimization problem. In addition to the above change, the IDM1 traded power is added to (4.10) and (4.11) for considering the arbitrage opportunity between SRM and IDM1.

$$\begin{aligned}
 & \sum_{c \in \mathcal{C}_b} (p_{c,t}^* + p_{(k=1),c,t}^{\text{ID}} + r_{v,c,t}^{\text{SR},\uparrow} - r_{v,c,t}^{\text{SR},\downarrow}) + \sum_{r \in \mathcal{R}_b} (p_{r,t}^* + p_{(k=1),r,t}^{\text{ID}} + r_{v,r,t}^{\text{SR},\uparrow} - r_{v,r,t}^{\text{SR},\downarrow}) \\
 & + \sum_{s \in \mathcal{S}_b} (p_{s,t}^* + p_{(k=1),s,t}^{\text{ID}} + r_{v,s,t}^{\text{SR},\uparrow} - r_{v,s,t}^{\text{SR},\downarrow}) \\
 & + \sum_{\theta \in \mathcal{O}_b} (p_{\theta,t}^* + p_{(k=1),\theta,t}^{\text{ID}} + r_{v,\theta,t}^{\text{SR},\uparrow} - r_{v,\theta,t}^{\text{SR},\downarrow}) - \sum_{\ell | i(\ell)=b} p_{v,\ell,t} + \sum_{\ell | j(\ell)=b} p_{v,\ell,t} \\
 & = p_{b,t}^* + p_{(k=1),b,t}^{\text{ID}} + r_{v,b,t}^{\text{SR}} + \sum_{d \in \mathcal{D}_b} (p_{d,t}^* + p_{(k=1),d,t}^{\text{ID}} - r_{v,d,t}^{\text{SR},\uparrow} + r_{v,d,t}^{\text{SR},\downarrow}), \\
 & \forall v \in \mathcal{V}, \forall b \in \mathcal{B}_m, \forall t \in \mathcal{T}
 \end{aligned} \tag{4.10}$$

$$\begin{aligned}
 & \sum_{c \in \mathcal{C}_b} (p_{c,t}^* + p_{(k=1),c,t}^{\text{ID}} + r_{v,c,t}^{\text{SR},\uparrow} - r_{v,c,t}^{\text{SR},\downarrow}) + \sum_{r \in \mathcal{R}_b} (p_{r,t}^* + p_{(k=1),r,t}^{\text{ID}} + r_{v,r,t}^{\text{SR},\uparrow} - r_{v,r,t}^{\text{SR},\downarrow}) \\
 & + \sum_{s \in \mathcal{S}_b} (p_{s,t}^* + p_{(k=1),s,t}^{\text{ID}} + r_{v,s,t}^{\text{SR},\uparrow} - r_{v,s,t}^{\text{SR},\downarrow}) \\
 & + \sum_{\theta \in \mathcal{O}_b} (p_{\theta,t}^* + p_{(k=1),\theta,t}^{\text{ID}} + r_{v,\theta,t}^{\text{SR},\uparrow} - r_{v,\theta,t}^{\text{SR},\downarrow}) - \sum_{\ell | i(\ell)=b} p_{v,\ell,t} + \sum_{\ell | j(\ell)=b} p_{v,\ell,t} \\
 & = \sum_{d \in \mathcal{D}_b} (p_{d,t}^* + p_{(k=1),d,t}^{\text{ID}} - r_{v,d,t}^{\text{SR},\uparrow} + r_{v,d,t}^{\text{SR},\downarrow}), \quad v \in \mathcal{V}, \forall b \in \mathcal{B}/\mathcal{B}_m, \forall t \in \mathcal{T}
 \end{aligned} \tag{4.11}$$

$$(4.6)-(4.9) \tag{4.12}$$

4.3.3 IDMs Supply-Demand Balancing Constraints

In the case of IDMs, the power resulted from DAM settlement, up/down reserve capacities resulted from SRM settlement, and the power of previous IDMs are fixed in the supply-demand constraints (4.13) and (4.14).

$$\begin{aligned}
 & \sum_{c \in \mathcal{C}_b} \left(p_{c,t}^* + \sum_{k=1}^{k-1} p_{k,c,t}^{\text{ID},*} + p_{k,c,t}^{\text{ID}} + r_{v,c,t}^{\text{SR},\uparrow,*} - r_{v,c,t}^{\text{SR},\downarrow,*} \right) \\
 & + \sum_{r \in \mathcal{R}_b} \left(p_{r,t}^* + \sum_{k=1}^{k-1} p_{k,r,t}^{\text{ID},*} + p_{k,r,t}^{\text{ID}} + r_{v,r,t}^{\text{SR},\uparrow,*} - r_{v,r,t}^{\text{SR},\downarrow,*} \right) \\
 & + \sum_{s \in \mathcal{S}_b} \left(p_{s,t}^* + \sum_{k=1}^{k-1} p_{k,s,t}^{\text{ID},*} + p_{k,s,t}^{\text{ID}} + r_{v,s,t}^{\text{SR},\uparrow,*} - r_{v,s,t}^{\text{SR},\downarrow,*} \right) \\
 & + \sum_{\theta \in \mathcal{O}_b} \left(p_{\theta,t}^* + \sum_{k=1}^{k-1} p_{k,\theta,t}^{\text{ID},*} + p_{k,\theta,t}^{\text{ID}} + r_{v,\theta,t}^{\text{SR},\uparrow,*} - r_{v,\theta,t}^{\text{SR},\downarrow,*} \right) - \sum_{\ell | i(\ell)=b} p_{v,\ell,t} \\
 & + \sum_{\ell | j(\ell)=b} p_{v,\ell,t} \\
 & = p_{b,t}^* + \sum_{k=1}^{k-1} p_{k,b,t}^{\text{ID},*} + p_{k,b,t}^{\text{ID}} + r_{v,b,t}^{\text{SR},*} \\
 & + \sum_{d \in \mathcal{D}_b} \left(p_{d,t}^* + \sum_{k=1}^{k-1} p_{k,d,t}^{\text{ID},*} + p_{k,d,t}^{\text{ID}} - r_{v,d,t}^{\text{SR},\uparrow,*} + r_{v,d,t}^{\text{SR},\downarrow,*} \right), \\
 & \forall v \in \mathcal{V}, \forall b \in \mathcal{B}_m, \forall t \geq \tau
 \end{aligned} \tag{4.13}$$

$$\begin{aligned}
& \sum_{c \in \mathcal{C}_b} \left(p_{c,t}^* + \sum_{k=1}^{k-1} p_{k,c,t}^{\text{ID},*} + p_{k,c,t}^{\text{ID}} + r_{v,c,t}^{\text{SR},\uparrow,*} - r_{v,c,t}^{\text{SR},\downarrow,*} \right) \\
& + \sum_{r \in \mathcal{R}_b} \left(p_{r,t}^* + \sum_{k=1}^{k-1} p_{k,r,t}^{\text{ID},*} + p_{k,r,t}^{\text{ID}} + r_{v,r,t}^{\text{SR},\uparrow,*} - r_{v,r,t}^{\text{SR},\downarrow,*} \right) \\
& + \sum_{s \in \mathcal{S}_b} \left(p_{s,t}^* + \sum_{k=1}^{k-1} p_{k,s,t}^{\text{ID},*} + p_{k,s,t}^{\text{ID}} + r_{v,s,t}^{\text{SR},\uparrow,*} - r_{v,s,t}^{\text{SR},\downarrow,*} \right) \\
& + \sum_{\theta \in \mathcal{O}_b} \left(p_{\theta,t}^* + \sum_{k=1}^{k-1} p_{k,\theta,t}^{\text{ID},*} + p_{k,\theta,t}^{\text{ID}} + r_{v,\theta,t}^{\text{SR},\uparrow,*} - r_{v,\theta,t}^{\text{SR},\downarrow,*} \right) - \sum_{\ell | i(\ell)=b} p_{v,\ell,t} \\
& + \sum_{\ell | j(\ell)=b} p_{v,\ell,t} = \sum_{d \in \mathcal{D}_b} \left(p_{d,t}^* + \sum_{k=1}^{k-1} p_{k,d,t}^{\text{ID},*} + p_{k,d,t}^{\text{ID}} - r_{v,d,t}^{\text{SR},\uparrow,*} + r_{v,d,t}^{\text{SR},\downarrow,*} \right), \\
& v \in \mathcal{V}, \forall b \in \mathcal{B}/\mathcal{B}_m, \forall t \geq \tau
\end{aligned} \tag{4.14}$$

4.3.4 DAM Power Traded Constraints

The DAM power traded to the main grid's constraints are explained in this section. The equations (4.15) and (4.16) limit the maximum and minimum power and reserve to be traded in the market, respectively. The constraints (4.17)-(4.19) define the total power, the up reserve, and the down reserve traded to the market according to the variables related to the main buses of the network. Equations (4.20) and (4.21) set the maximum and minimum power traded to the market for the transmission line or power transformer connected to the main buses of the network, respectively.

$$p_t^{\text{DA}} + r_t^{\text{SR},\uparrow} \leq \sum_{c \in \mathcal{C}} \bar{p}_c + \sum_{r \in \mathcal{R}} \bar{p}_r + \sum_{\theta \in \mathcal{O}} \bar{p}_\theta + \sum_{s \in \mathcal{S}} \bar{p}_s^-, \quad \forall t \in \mathcal{T} \tag{4.15}$$

$$-\left(\sum_{d \in \mathcal{D}} \bar{p}_d + \sum_{s \in \mathcal{S}} \bar{p}_s^+ \right) \leq p_t^{\text{DA}} - r_t^{\text{SR},\downarrow}, \quad \forall t \in \mathcal{T} \tag{4.16}$$

$$p_t^{\text{DA}} = \sum_{b \in \mathcal{B}_m} p_{b,t}, \quad \forall t \in \mathcal{T} \tag{4.17}$$

$$r_t^{\text{SR},\uparrow} = \sum_{b \in \mathcal{B}_m} r_{b,t}^{\text{SR},\uparrow}, \quad \forall t \in \mathcal{T} \tag{4.18}$$

$$r_t^{\text{SR},\downarrow} = \sum_{b \in \mathcal{B}_m} r_{b,t}^{\text{SR},\downarrow}, \quad \forall t \in \mathcal{T} \tag{4.19}$$

$$p_{b,t} + r_{b,t}^{\text{SR},\uparrow} \leq \bar{p}_b, \quad \forall b \in \mathcal{B}_m, \forall t \in \mathcal{T} \tag{4.20}$$

$$-\bar{p}_b \leq p_{b,t} - r_{b,t}^{\text{SR},\downarrow}, \quad \forall b \in \mathcal{B}_m, \forall t \in \mathcal{T} \tag{4.21}$$

4.3.5 SRM Power Traded Constraints

The SRM constraints (4.22)-(4.27) are similar to the DAM version. However, there are some differences. First, the power that had already traded in the DAM is fixed in these constraints. Second, the IDM1 power is added to these constraints, and its value is assigned by summation on IDM1 power of all main grid buses in (4.24).

$$p_t^{\text{DA},*} + p_{(k=1),t}^{\text{ID}} + r_t^{\text{SR},\uparrow} \leq \sum_{c \in \mathcal{C}} \bar{P}_c + \sum_{r \in \mathcal{R}} \bar{P}_{r,t} + \sum_{\theta \in \Theta} \bar{P}_\theta + \sum_{s \in \mathcal{S}} \bar{P}_s^-, \quad \forall t \in \mathcal{T} \quad (4.22)$$

$$-\left(\sum_{d \in \mathcal{D}} \bar{P}_{d,t} + \sum_{s \in \mathcal{S}} \bar{P}_s^+ \right) \leq p_t^{\text{DA},*} + p_{(k=1),t}^{\text{ID}} - r_t^{\text{SR},\downarrow}, \quad \forall t \in \mathcal{T} \quad (4.23)$$

$$p_{(k=1),t}^{\text{ID}} = \sum_{b \in \mathcal{B}_m} p_{(k=1),b,t}^{\text{ID}}, \quad \forall t \in \mathcal{T} \quad (4.24)$$

$$p_{b,t}^* + p_{(k=1),b,t}^{\text{ID}} + r_{b,t}^{\text{SR},\uparrow} \leq \bar{P}_b, \quad \forall b \in \mathcal{B}_m, \forall t \in \mathcal{T} \quad (4.25)$$

$$-\bar{P}_b \leq p_{b,t}^* + p_{(k=1),b,t}^{\text{ID}} - r_{b,t}^{\text{SR},\downarrow}, \quad \forall b \in \mathcal{B}_m, \forall t \in \mathcal{T} \quad (4.26)$$

$$(4.25)-(4.26) \quad (4.27)$$

4.3.6 IDMs Power Traded Constraints

The IDMs power traded in each session is calculating according to (4.28)-(4.32). The DAM power, the up and down reserve, and the power related to previous IDMs, which had already been assigned in the previous markets, are fixed in these equations.

$$p_t^{\text{DA},*} + \sum_{k=1}^{k-1} p_{k,t}^{\text{ID},*} + p_{k,t}^{\text{ID}} + r_t^{\text{SR},\uparrow,*} \leq \sum_{c \in \mathcal{C}} \bar{P}_c + \sum_{r \in \mathcal{R}} \bar{P}_{r,t} + \sum_{\theta \in \Theta} \bar{P}_\theta + \sum_{s \in \mathcal{S}} \bar{P}_s^-, \quad \forall k \in \mathcal{K}, \forall t \geq \tau \quad (4.28)$$

$$-\left(\sum_{d \in \mathcal{D}} \bar{P}_{d,t} + \sum_{s \in \mathcal{S}} \bar{P}_s^+ \right) \leq p_t^{\text{DA},*} + \sum_{k=1}^{k-1} p_{k,t}^{\text{ID},*} + p_{k,t}^{\text{ID}} - r_t^{\text{SR},\downarrow,*}, \quad \forall k \in \mathcal{K}, \forall t \geq \tau \quad (4.29)$$

$$p_{k,t}^{\text{ID}} = \sum_{b \in \mathcal{B}_m} p_{k,b,t}^{\text{ID}}, \quad \forall k \in \mathcal{K}, \forall t \geq \tau \quad (4.30)$$

$$p_{b,t}^* + \sum_{k=1}^{k-1} p_{k,b,t}^{\text{ID},*} + p_{k,b,t}^{\text{ID}} + r_{b,t}^{\text{SR},\uparrow,*} \leq \bar{P}_b, \quad \forall k \in \mathcal{K}, \forall b \in \mathcal{B}_m, \forall t \in \mathcal{T} \quad (4.31)$$

$$-\bar{P}_b \leq p_{b,t}^* + \sum_{k=1}^{k-1} p_{k,b,t}^{\text{ID},*} + p_{k,b,t}^{\text{ID}} - r_{b,t}^{\text{SR},\downarrow,*}, \quad \forall b \in \mathcal{B}_m, \forall t \in \mathcal{T} \quad (4.32)$$

4.3.7 DC Power Flow Constraints

The equations for a DC, lossless power flow used for active power trading in DAM and SRM are presented below. Note that, for IDMs participation, the time periods vary from $\forall t \in \mathcal{T}$ to $\forall t \geq \tau$. The active power flow through line ℓ is represented in (4.33), whereas the bounds of active power flow through line ℓ are imposed by (4.34). Finally, the voltage angle reference and angle limits are set by (4.35) and (4.36), respectively.

$$\frac{p_{v,\ell,t}}{S^B} = \frac{1}{X_\ell} (\delta_{v,i(\ell),t} - \delta_{v,j(\ell),t}), \quad \forall v \in \mathcal{V}, \forall \ell \in \mathcal{L}, \forall t \in \mathcal{T} \quad (4.33)$$

$$-\bar{P}_\ell \leq p_{v,\ell,t} \leq \bar{P}_\ell, \quad \forall v \in \mathcal{V}, \forall \ell \in \mathcal{L}, \forall t \in \mathcal{T} \quad (4.34)$$

$$\delta_{v,b,t} = 0, \quad b : \text{ref.}, \forall v \in \mathcal{V}, \forall t \in \mathcal{T} \quad (4.35)$$

$$-\pi \leq \delta_{v,b,t} \leq \pi, \quad \forall b \in \mathcal{B} \setminus b : \text{ref.}, \forall v \in \mathcal{V}, \forall t \in \mathcal{T} \quad (4.36)$$

4.4 Dispatchable Renewable Energy Sources

The first group of DVPP components discussed in this Section is the conventional, synchronous, dispatchable RESs such as hydroelectric and biomass generation. These systems, specially the hydro generation, have been present in market pools since the establishment of the electric energy market. They are characterized by usually large power and energy capacities, relatively high ramp rates and low *fuel* costs, and long lifetime.

These features make large-scale D-RESs highly competitive in the energy markets as individual offerors. However, their relevance to participate in such markets jointly with other assets is apparent. On one hand, smaller-scale D-RESs can improve their competitiveness by joining "efforts" among them, as well as with components of other nature such as ND-RESs and ESSs. Moreover, large-scale D-RESs can largely increase the competitiveness and improve the operation of stochastic ND-RESs if working jointly as a DVPP, in lieu of slightly worsening their individual market position.

The equations that model a set of D-RESs belonging to a DVPP are listed below.

4.4.1 D-RES Constraints in the DAM

Constraints (4.37)-(4.38) define the commitment status of D-RES. Constraints (4.39)-(4.40) limit the maximum and minimum production of each D-RES. In (4.41)-(4.42), the ramp-up/down rates of each D-RES are restricted considering the worst cases of reserve activation. For example, the worst case for the ramp-up constraint is when D-RES activates the down reserve in the last minutes of $(t - 1)$ period and the up reserve in the first minutes of t period, respectively. The alias indices v' (same as indices v) are used here to show all combinations for providing up/down reserve in two sequential time periods. There are four possibilities, since when the DVPP requests for up reserve, D-RES can provide the up or down reserve. In the opposite condition, when DVPP requests for down reserve, D-RES can offer either up or down reserve. Constraints (4.43)-(4.44) restrict the up/down reserve of D-RES considering the activation time of reserve and SR ramp rate capabilities of D-RES. Besides, the binary variable $u_{v,c,t}^{SR}$ does not allow that a D-RES provides up and down reserve at the same time. Constraints (4.45)-(4.46) illustrate the start-up and shut-down costs of D-RES as a linearized function.

Minimum up and down time of D-RESs are illustrated in (4.47)-(4.52) and adopted from [18]. The parameters $N_c^{on} = \text{Min}\{T, (UT_c - UP_c^0)U_c^0\}$ and $N_c^{off} = \text{Min}\{T, (DT_c - DO_c^0)(1 - U_c^0)\}$ are the number of initial periods during which D-RESs must be online/offline, respectively. Equation (4.47) defines the initial status of D-RESs as defined by N_c^{on} . Constraint (4.48) restricts the minimum up time during all combination of the subsequent periods UT_c . Constraint (4.49) defines the minimum up time for the final periods $UT_c - 1$. Constraints (4.50)-(4.52) are the minimum down time version of (4.47)-(4.49). Constraints (4.53)-(4.54) impose that the start-up and shut-down costs of D-RES are positive. Finally, constraint (4.55) shows the nature of binary variables.

$$u_{c,t} - u_{c,(t-1)} = v_{c,t}^1 - v_{c,t}^0, \quad \forall c \in \mathcal{C}, \forall t \in \mathcal{T} \quad (4.37)$$

$$v_{c,t}^1 + v_{c,t}^0 \leq 1, \quad \forall c \in \mathcal{C}, \forall t \in \mathcal{T} \quad (4.38)$$

$$p_{c,t} + r_{v,c,t}^{SR,\uparrow} \leq \bar{P}_c u_{c,t}, \quad \forall v \geq 1, \forall c \in \mathcal{C}, \forall t \in \mathcal{T} \quad (4.39)$$

$$\underline{P}_c u_{c,t} \leq p_{c,t} - r_{v,c,t}^{SR,\downarrow}, \quad \forall c \in \mathcal{C}, \forall t \in \mathcal{T} \quad (4.40)$$

$$\begin{aligned} (p_{c,t} + r_{v',c,t}^{\text{SR},\uparrow}) - (p_{c,(t-1)} - r_{v,c,(t-1)}^{\text{SR},\downarrow}) &\leq (\bar{R}_c u_{c,(t-1)} + R_c^1 v_{c,t}^1) \Delta t, \\ \forall v \geq 1, \forall v' \geq 1, \forall c \in \mathcal{C}, \forall t \in \mathcal{T} \end{aligned} \quad (4.41)$$

$$\begin{aligned} (p_{c,(t-1)} + r_{v',c,(t-1)}^{\text{SR},\uparrow}) - (p_{c,t} - r_{v,c,t}^{\text{SR},\downarrow}) &\leq (\underline{R}_c u_{c,t} + R_c^0 v_{c,t}^0) \Delta t, \\ \forall v \geq 1, \forall v' \geq 1, \forall c \in \mathcal{C}, \forall t \in \mathcal{T} \end{aligned} \quad (4.42)$$

$$r_{v,c,t}^{\text{SR},\uparrow} \leq T^{\text{SR}} \bar{R}_c^{\text{SR}} u_{v,c,t}^{\text{SR}}, \quad \forall v \geq 1, \forall c \in \mathcal{C}, \forall t \in \mathcal{T} \quad (4.43)$$

$$r_{v,c,t}^{\text{SR},\downarrow} \leq T^{\text{SR}} \underline{R}_c^{\text{SR}} (1 - u_{v,c,t}^{\text{SR}}), \quad \forall v \geq 1, \forall c \in \mathcal{C}, \forall t \in \mathcal{T} \quad (4.44)$$

$$C_c^1(u_{c,t} - u_{c,(t-1)}) \leq c_{c,t}^1, \quad \forall c \in \mathcal{C}, \forall t \in \mathcal{T} \quad (4.45)$$

$$C_c^0(u_{c,(t-1)} - u_{c,t}) \leq c_{c,t}^0, \quad \forall c \in \mathcal{C}, \forall t \in \mathcal{T} \quad (4.46)$$

$$\sum_{t=1}^{N_c^{\text{On}}} (1 - u_{c,t}) = 0, \quad \forall c \in \mathcal{C} \quad (4.47)$$

$$UT_c(u_{c,t} - u_{c,(t-1)}) \leq \sum_{t'=t}^{t+UT_c-1} u_{c,t'}, \quad \forall c \in \mathcal{C}, \forall t = N_c^{\text{On}} + 1, \dots, T - UT_c + 1 \quad (4.48)$$

$$0 \leq \sum_{t'=t}^T [u_{c,t'} - (u_{c,t} - u_{c,(t-1)})], \quad \forall c \in \mathcal{C}, \forall t = T - UT_c + 2, \dots, T \quad (4.49)$$

$$\sum_{t=1}^{N_c^{\text{Off}}} u_{c,t} = 0, \quad \forall c \in \mathcal{C} \quad (4.50)$$

$$DT_c(u_{c,(t-1)} - u_{c,t}) \leq \sum_{t'=t}^{t+DT_c-1} (1 - u_{c,t'}), \quad \forall c \in \mathcal{C}, \forall t = N_c^{\text{Off}} + 1, \dots, T - DT_c + 1 \quad (4.51)$$

$$0 \leq \sum_{t'=t}^T [1 - u_{c,t'} - (u_{c,(t-1)} - u_{c,t})], \quad \forall c \in \mathcal{C}, \forall t = T - DT_c + 2, \dots, T \quad (4.52)$$

$$0 \leq c_{c,t}^1, \quad \forall c \in \mathcal{C}, \forall t \in \mathcal{T} \quad (4.53)$$

$$0 \leq c_{c,t}^0, \quad \forall c \in \mathcal{C}, \forall t \in \mathcal{T} \quad (4.54)$$

$$u_{v,c,t}^{\text{SR}}, u_{c,t}, v_{c,t}^0, v_{c,t}^1 \in \{0,1\}, \quad \forall v \geq 1, \forall c \in \mathcal{C}, \forall t \in \mathcal{T} \quad (4.55)$$

4.4.2 D-RES Constraints in the SRM

The SRM constraints of D-RES are shown in equations (4.56)-(4.60). These constraints are similar to the DAM version, but the power of DAM is fixed. On the other hand, the power related to the IDM1 is added to the D-RES constraints when necessary.

$$p_{c,t}^* + r_{v,c,t}^{\text{SR},\uparrow} + p_{(k=1),c,t}^{\text{ID}} \leq \bar{P}_c u_{c,t}, \quad \forall v \geq 1, \forall c \in \mathcal{C}, \forall t \in \mathcal{T} \quad (4.56)$$

$$\underline{P}_c u_{c,t} \leq p_{c,t}^* + p_{(k=1),c,t}^{\text{ID}} - r_{v,c,t}^{\text{SR},\downarrow}, \quad \forall v \geq 1, \forall c \in \mathcal{C}, \forall t \in \mathcal{T} \quad (4.57)$$

$$\left(p_{c,t}^* + p_{(k=1),c,t}^{\text{ID}} + r_{v',c,t}^{\text{SR},\uparrow}\right) - \left(p_{c,(t-1)}^* + p_{(k=1),c,t}^{\text{ID}} - r_{v,c,(t-1)}^{\text{SR},\downarrow}\right) \leq (\bar{R}_c u_{c,(t-1)} + R_c^1 v_{c,t}^1) \Delta t, \quad (4.58)$$

$$\forall v \geq 1, \forall v' \geq 1, \forall c \in \mathcal{C}, \forall t \in \mathcal{T}$$

$$\left(p_{c,(t-1)}^* + p_{(k=1),c,(t-1)}^{\text{ID}} + r_{v',c,(t-1)}^{\text{SR},\uparrow}\right) - \left(p_{c,t}^* + p_{(k=1),c,t}^{\text{ID}} - r_{v,c,t}^{\text{SR},\downarrow}\right) \leq (\underline{R}_c u_{c,t} + R_c^0 v_{c,t}^0) \Delta t, \quad (4.59)$$

$$\forall v \geq 1, \forall v' \geq 1, \forall c \in \mathcal{C}, \forall t \in \mathcal{T}$$

$$(4.37) - (4.38), (4.43) - (4.55) \quad (4.60)$$

4.4.3 D-RES Constraints in the IDM

The constraints of D-RES in the IDMs are depicted in (4.61)-(4.77). The DAM power, the up and down reserve, and the power related to previous IDMs, which had already been assigned in the previous markets, are fixed in these equations. Besides, in (4.63)-(4.65) the maximum value between D-RES assigned reserve in the SRM when DVPP calls for up and down reserve is selected to assure the worst cases. The minimum up and down time in (4.69)-(4.74) are changed by considering each IDM session's beginning. Therefore, the parameters $N_{k,c}^{\text{on}} = \text{Min}\{T - \tau, (UT_c - UP_{k,c}^0)U_{k,c}^0\}$ and $N_{k,c}^{\text{off}} = \text{Min}\{T - \tau, (DT_c - DP_{k,c}^0)(1 - U_{k,c}^0)\}$ are modified accordingly.

$$u_{c,t} - u_{c,(t-1)} = v_{c,t}^1 - v_{c,t}^0, \quad \forall c \in \mathcal{C}, \forall t \in \mathcal{T} \quad (4.61)$$

$$v_{c,t}^1 + v_{c,t}^0 \leq 1, \quad \forall c \in \mathcal{C}, \forall t \in \mathcal{T} \quad (4.62)$$

$$p_{c,t}^* + \max(r_{(v=1),c,t}^{\text{SR},\uparrow,*}, r_{(v=2),c,t}^{\text{SR},\uparrow,*}) + \sum_{k=1}^{k-1} p_{k,c,t}^{\text{ID},*} + p_{k,c,t}^{\text{ID}} \leq \bar{P}_c u_{c,t}, \quad \forall k \in \mathcal{K}, \forall c \in \mathcal{C}, \forall t \geq \tau \quad (4.63)$$

$$\underline{P}_c u_{c,t} \leq p_{c,t}^* + \sum_{k=1}^{k-1} p_{k,c,t}^{\text{ID},*} + p_{k,c,t}^{\text{ID}} - \max(r_{(v=1),c,t}^{\text{SR},\downarrow,*}, r_{(v=2),c,t}^{\text{SR},\downarrow,*}), \quad \forall k \in \mathcal{K}, \forall c \in \mathcal{C}, \forall t \geq \tau \quad (4.64)$$

$$\left(p_{c,t}^* + \sum_{k=1}^{k-1} p_{k,c,t}^{\text{ID},*} + p_{k,c,t}^{\text{ID}} + \max(r_{(v=1),c,t}^{\text{SR},\uparrow,*}, r_{(v=2),c,t}^{\text{SR},\uparrow,*})\right) \quad (4.65)$$

$$- \left(p_{c,(t-1)}^* + \sum_{k=1}^{k-1} p_{k,c,(t-1)}^{\text{ID},*} + p_{k,c,(t-1)}^{\text{ID}} - \max(r_{(v=1),c,(t-1)}^{\text{SR},\downarrow,*}, r_{(v=2),c,(t-1)}^{\text{SR},\downarrow,*})\right)$$

$$\leq (\bar{R}_c u_{c,(t-1)} + R_c^1 v_{c,t}^1) \Delta t, \quad \forall k \in \mathcal{K}, \forall c \in \mathcal{C}, \forall t \geq \tau$$

$$\left(p_{c,(t-1)}^* + \sum_{k=1}^{k-1} p_{k,c,(t-1)}^{\text{ID},*} + p_{k,c,(t-1)}^{\text{ID}} + \max(r_{(v=1),c,(t-1)}^{\text{SR},\uparrow,*}, r_{(v=2),c,(t-1)}^{\text{SR},\uparrow,*})\right) \quad (4.66)$$

$$- \left(p_{c,t}^* + \sum_{k=1}^{k-1} p_{k,c,t}^{\text{ID},*} + p_{k,c,t}^{\text{ID}} - \max(r_{(v=1),c,t}^{\text{SR},\downarrow,*}, r_{(v=2),c,t}^{\text{SR},\downarrow,*})\right)$$

$$\leq (\underline{R}_c u_{c,t} + R_c^0 v_{c,t}^0) \Delta t, \quad \forall k \in \mathcal{K}, \forall c \in \mathcal{C}, \forall t \geq \tau$$

$$C_c^1(u_{c,t} - u_{c,(t-1)}) \leq c_{k,c,t}^1, \quad \forall k \in \mathcal{K}, \forall c \in \mathcal{C}, \forall t \geq \tau \quad (4.67)$$

$$C_c^0(u_{c,(t-1)} - u_{c,t}) \leq c_{k,c,t}^0, \quad \forall k \in \mathcal{K}, \forall c \in \mathcal{C}, \forall t \geq \tau \quad (4.68)$$

$$\sum_{t=1}^{\tau-1+N_{k,c}^{\text{on}}} (1 - u_{c,t}) = 0, \quad \forall k \in \mathcal{K}, \forall c \in \mathcal{C} \quad (4.69)$$

$$UT_c(u_{c,t} - u_{c,(t-1)}) \leq \sum_{t'=t}^{t+UT_c-1} u_{c,t'}, \forall k \in \mathcal{K}, \forall c \in \mathcal{C}, \forall t = \tau + N_{k,c}^{\text{on}}, \dots, T - UT_c + 1 \quad (4.70)$$

$$0 \leq \sum_{t'=t}^T [u_{c,t'} - (u_{c,t} - u_{c,(t-1)})], \quad \forall c \in \mathcal{C}, \forall t = T - UT_c + 2, \dots, T \quad (4.71)$$

$$\sum_{t=\tau}^{\tau-1+N_{k,c}^{\text{off}}} u_{c,t} = 0, \quad \forall k \in \mathcal{K}, \forall c \in \mathcal{C} \quad (4.72)$$

$$DT_c(u_{c,(t-1)} - u_{c,t}) \leq \sum_{t'=t}^{t+DT_c-1} (1 - u_{c,t'}), \quad \forall k \in \mathcal{K}, \forall c \in \mathcal{C}, \forall t = \tau + N_c^{\text{off}}, \dots, T - DT_c + 1 \quad (4.73)$$

$$0 \leq \sum_{t'=t}^T [1 - u_{c,t'} - (u_{c,(t-1)} - u_{c,t})], \quad \forall k \in \mathcal{K}, \forall c \in \mathcal{C}, \forall t = T - DT_c + 2, \dots, T \quad (4.74)$$

$$0 \leq c_{k,c,t}^1, \quad \forall k \in \mathcal{K}, \forall c \in \mathcal{C}, \forall t \geq \tau \quad (4.75)$$

$$0 \leq c_{k,c,t}^0, \quad \forall k \in \mathcal{K}, \forall c \in \mathcal{C}, \forall t \geq \tau \quad (4.76)$$

$$u_{c,t}, v_{c,t}^0, v_{c,t}^1 \in \{0,1\}, \quad \forall c \in \mathcal{C}, \forall t \geq \tau \quad (4.77)$$

4.5 Nondispatchable Stochastic Renewable Energy Sources

Although D-RESs show a large number of remarkable advantages, they nevertheless have important disadvantages that prevent having a 100% D-RES scenario in practice. For instance, large-scale hydroelectric power plants are currently exploited up to nearly the maximum possible due to the orographic limitations that are intrinsic of this technology. Regarding biomass generation, they have associated installation and operation costs that usually surpass those of other solutions based on ND-RESs such as wind and solar generation.

Due to the reasons above, the penetration of ND-RESs has experienced a striking growth over the past few decades. However, the stochastic nature of their sources (wind and sun) implies ND-RESs being less reliable when having to ensure a certain amount of power injection over a sufficiently long time period. This makes ND-RESs not suitable for participating in the energy markets, as failing to comply with the contracted power in the DAM will lead to penalties from the market operators. Therefore, ND-RESs usually include a control scheme that ensures the generation of the maximum amount of active power possible according to the availability of the renewable sources, in exchange of a given price of the energy that is generally lower than that associated to market participants.

However, by integrating several ND-RESs and other flexible assets, the competitiveness of ND-RESs in the energy markets and even in the ancillary service markets can be improved, so much so that they could even become price makers, i.e., they can impact on the final price after market clearance, thus maximizing even further their profit.

The model of the ND-DERs used in the model core discussed previously in this Chapter is described below.

As opposed to the D-DERs, which are based on synchronous machines, and thus, show ramping limitations between time periods, ND-RESs are generally based on power inverters, and thus, their response times are much faster. Ramping limitations can therefore be neglected when modeling ND-DERs for the purposes of this work. Moreover, start-up and shut-down can also be considered to be zero. Therefore, the constraints that characterize the behavior of ND-RESs are as follows.

Note that, despite the apparent simplicity of the ND-RES model considered, it hides a crucial source of complexity, namely, the definition of the value of the available renewable source, $P_{r,t}$, as it is characterized by an uncertainty that is, in some cases, arduous to predict. Chapter 5 specifically deals with the characterization of such uncertainties, as well as those of price and demand profiles.

4.5.1 ND-RES Constraints in the DAM

The ND-RES power and reserve provided in the DAM are constrained by equations (4.78)-(4.82). Constraints (4.78)-(4.79) assign the maximum and minimum power provided by ND-RES, respectively. The binary variable $u_{v,r,t}$ assures the output power of ND-RESs to be zero when they are off. Constraints (4.80)-(4.81) limit the up/down reserve that each ND-RES can provide when the DVPP calls for up or down reserve. Constraint (4.82) shows the binary nature of $u_{v,r,t}^{SR}$, which does not allow providing both up and down reserve at the same time.

$$p_{r,t} + r_{v,r,t}^{SR,\uparrow} \leq \bar{P}_{r,t} u_{v,r,t}, \quad \forall v \geq 1, r \in \mathcal{R}, \forall t \in \mathcal{T} \quad (4.78)$$

$$\underline{P}_{r,t} u_{v,r,t} \leq p_{r,t} - r_{v,r,t}^{SR,\downarrow}, \quad \forall v \geq 1, \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \quad (4.79)$$

$$r_{v,r,t}^{SR,\uparrow} \leq T^{SR} \bar{R}_r^{SR} u_{v,r,t}^{SR}, \quad \forall v \geq 1, \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \quad (4.80)$$

$$r_{v,r,t}^{SR,\downarrow} \leq T^{SR} \underline{R}_r^{SR} (1 - u_{v,r,t}^{SR}), \quad \forall v \geq 1, \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \quad (4.81)$$

$$u_{v,r,t}, u_{v,r,t}^{SR} \in \{0,1\}, \forall v \geq 1, \quad \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \quad (4.82)$$

4.5.2 ND-RES Constraints in the SRM

The ND-RES power and reserve limitations in the SRM are similar to the DAM, with some differences. The power related to the DAM is fixed, and the IDM1 power is added to (4.83)-(4.84).

$$p_{r,t}^* + r_{v,r,t}^{SR,\uparrow} + p_{(k=1),r,t}^{ID} \leq \bar{P}_{r,t} u_{v,r,t}, \quad \forall v \geq 1, \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \quad (4.83)$$

$$\underline{P}_{r,t} u_{v,r,t} \leq p_{r,t}^* - r_{v,r,t}^{SR,\downarrow} + p_{(k=1),r,t}^{ID}, \quad \forall v \geq 1, \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \quad (4.84)$$

$$(4.80) - (4.82) \quad (4.85)$$

4.5.3 ND-RES Constraints in the IDMs

The ND-RES power produced in each session of the IDMs is limited in (5.3a)-(5.3b) according to the DAM fixed power, the maximum amount of up or down reserve assigned in the SRM, and the previous IDMs fixed power.

$$p_{r,t}^* + \max\{r_{(v=1),c,t}^{SR,\uparrow,*}, r_{(v=2),c,t}^{SR,\uparrow,*}\} + \sum_{k=1}^{k-1} p_{k,r,t}^{ID,*} + p_{k,r,t}^{ID} \leq \bar{p}_{r,t} u_{v,r,t}, \quad \forall k \in \mathcal{K}, \forall r \in \mathcal{R}, \forall t \geq \tau \quad (4.86)$$

$$p_{r,t} u_{v,r,t} \leq p_{r,t}^* - \max\{r_{(v=1),c,t}^{SR*,\downarrow}, r_{(v=2),c,t}^{SR*,\downarrow}\} + \sum_{k=1}^{k-1} p_{k,r,t}^{ID,*} + p_{k,r,t}^{ID}, \quad \forall k \in \mathcal{K}, \forall r \in \mathcal{R}, \forall t \geq \tau \quad (4.87)$$

4.6 Flexible Demand

Another key component of DVPPs are the flexible loads or demands, which allow modifying their active power consumption, either for regulation or market purposes, or both. Flexible demands include (i) interruptible loads, whose consumption can be partially or totally reduced in discrete intervals; (ii) continuously regulated loads, such as an aggregation of thermostatically controlled loads; and (iii) EV fleets. To achieve a relevant and efficient demand flexibility is not a simple task [19]. First, the widespread installation of smart meters at the demand side, as well as the real-time communication of the energy price information are essential. This also implies the existence of a fast, secure and efficient communication infrastructure to coordinate all individual demands in order to properly construct load aggregations.

The models that define the response of the different generating units (D-RES and ND-RES) of the DVPP are, with the relevant exception of the STU (see Section 4.8), generally well-posed and widely studied. However, modelling flexible demands who can vary their power consumption according to a given strategy for market participation is still an open topic. This is due to the absence of appropriate measures of benefits for consumers that provide such flexibility actions. While technical constraints and economic costs of generating units are well-known by its owners, few reliable tools have been formally provided to load owners to have full control over what value they assign to this flexibility provision. In particular, DVPPs with flexible demands and who offer prices to those demand owners for their flexibility provision have not been considered in previous literature.

This Section presents and discusses the model proposed in this work that fills the gap above. We propose a demand model with bi-level flexibility associated with different energy market trading sessions [20]. In contrast to other studies, the demand owner maintains high level of control over its own consumption by setting different profiles which the DVPP manager can choose from in DAM at a cost. Moreover, the demand owner allows tolerances around the chosen profile at IDM at no cost.

The set of equations that model the flexible demands considered in this WP is provided below. Note that, at this stage, EVs are considered to have the grid-to-vehicle (G2V) technology, thus they are only capable of modifying their speed of charge, and thus their aggregated active power consumption. Therefore, their model is *the same*⁷ as that of other flexible demand types. Later stages of the project will consider the possibility of including the vehicle-to-grid (V2G) technology. In that case, EVs will be included in the category of energy storage systems, as both charge and discharge stages of the EV batteries is enabled.

⁷ The main difference between EV fleets and other flexible demand types regards the uncertainties of the charging behavior of the EVs

4.6.1 Flexible Demands Constraints in the DAM

Constraint (4.88) selects one of the predefined profiles of demands. Constraint (4.89) assures that only one profile between several profiles of the load is selected. Constraints (4.90) and (4.91) limit the up/down reserve by a specified amount of load selected by constraint (4.88). The ramp-up and ramp-down limitations of load are restricted by (4.92) and (4.93). These constraints define the worse condition of the ramp rate of the load when up and down reserve be activated in two sequential periods. Constraints (4.94) and (4.95) bound the load capability for providing the up/down reserve. Binary variable $u_{v,d,t}^{SR}$ does not let both up and down reserve at the same time. Constraint (4.96) confines the minimum energy that the demand should use. This equation is written for the worse condition of providing reserve when the demand at all periods provides the maximum up reserve. The auxiliary variable $r_{d,t}^{SR,\uparrow}$ assigns the maximum value of up reserve provided by demand between $v = 1$ and $v = 2$ according to constraint (4.97). Finally, constraint (4.98) defines the nature of binary variable $u_{v,d,t}^{SR}$.

$$p_{d,t} = \sum_{p \in \mathcal{P}} P_{d,p,t} u_{d,p}, \quad \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \quad (4.88)$$

$$\sum_{p \in \mathcal{P}} u_{d,p} = 1, \quad \forall d \in \mathcal{D} \quad (4.89)$$

$$r_{v,d,t}^{SR,\downarrow} \leq \left(\frac{\bar{P}_{d,t}}{100} \right) p_{d,t}, \quad \forall v \geq 1, \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \quad (4.90)$$

$$r_{v,d,t}^{SR,\uparrow} \leq \left(\frac{P_{d,t}}{100} \right) p_{d,t}, \quad \forall v \geq 1, \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \quad (4.91)$$

$$(p_{d,t} + r_{v',d,t}^{SR,\downarrow}) - (p_{d,(t-1)} - r_{v,d,(t-1)}^{SR,\uparrow}) \leq \bar{R}_d \Delta t, \quad \forall v \geq 1, \forall v' \geq 1, \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \quad (4.92)$$

$$(p_{d,(t-1)} + r_{v',d,(t-1)}^{SR,\downarrow}) - (p_{d,t} - r_{v,d,t}^{SR,\uparrow}) \leq \underline{R}_d \Delta t, \quad \forall v \geq 1, \forall v' \geq 1, \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \quad (4.93)$$

$$r_{v,d,t}^{SR,\downarrow} \leq T^{SR} \bar{R}_d^{SR} (1 - u_{v,d,t}^{SR}), \quad \forall v \geq 1, \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \quad (4.94)$$

$$r_{v,d,t}^{SR,\uparrow} \leq T^{SR} \underline{R}_d^{SR} u_{v,d,t}^{SR}, \quad \forall v \geq 1, \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \quad (4.95)$$

$$E_d \leq \sum_{t \in \mathcal{T}} (p_{d,t} \Delta t - F^{SR} r_{d,t}^{SR,\uparrow}), \quad \forall v \geq 1, \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \quad (4.96)$$

$$r_{v,d,t}^{SR,\uparrow} \leq r_{d,t}^{SR,\uparrow}, \quad \forall v \geq 1, \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \quad (4.97)$$

$$u_{v,d,t}^{SR} \in \{0,1\}, \quad \forall v \geq 1, \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \quad (4.98)$$

4.6.2 Flexible Demands Constraints in the SRM

The constraints of demand in the SRM are like DAM constraints with some differences. The DAM power of demand is fixed at its optimal solution, and IDM1 power of demand is added to the equations (4.99)-(4.103) to ensure the arbitrage strategy for DVPP.

$$p_{(k=1),d,t}^{\text{ID}} + r_{v,d,t}^{\text{SR},\downarrow} \leq \left(\frac{\bar{P}_{d,t}}{100}\right) p_{d,t}^*, \quad \forall v \geq 1, \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \quad (4.99)$$

$$p_{(k=1),d,t}^{\text{ID}} - r_{v,d,t}^{\text{SR},\uparrow} \leq \left(\frac{\underline{P}_{d,t}}{100}\right) p_{d,t}^*, \quad \forall v \geq 1, \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \quad (4.100)$$

$$(p_{d,t}^* + p_{(k=1),d,t}^{\text{ID}} + r_{v',d,t}^{\text{SR},\downarrow}) - (p_{d,(t-1)}^* + p_{(k=1),d,(t-1)}^{\text{ID}} - r_{v,d,(t-1)}^{\text{SR},\uparrow}) \leq \bar{R}_d \Delta t, \quad \forall v \geq 1, \forall v' \geq 1, \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \quad (4.101)$$

$$(p_{d,(t-1)}^* + p_{(k=1),d,(t-1)}^{\text{ID}} + r_{v',d,(t-1)}^{\text{SR},\downarrow}) - (p_{d,t}^* + p_{(k=1),d,t}^{\text{ID}} - r_{v,d,t}^{\text{SR},\uparrow}) \leq \underline{R}_d \Delta t, \quad \forall v \geq 1, \forall v' \geq 1, \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \quad (4.102)$$

$$\underline{E}_d \leq \sum_{t \in \mathcal{T}} (p_{d,t}^* \Delta t + p_{(k=1),d,t}^{\text{ID}} \Delta t - F^{\text{SR}} r_{d,t}^{\text{SR},\uparrow}), \quad \forall d \in \mathcal{D} \quad (4.103)$$

$$(4.94) - (4.95), (4.97) - (4.98) \quad (4.104)$$

4.6.3 Flexible Demands Constraints in IDMs

The constraints of the demand in the IDMs are shown in (4.105)-(4.109). The DAM power of demand, the maximum reserve assigned in the SRM, and the power of demand in the previous IDMs are fixed at their optimal values.

$$\sum_{k=1}^{k-1} p_{k,d,t}^{\text{ID},*} + p_{k,d,t}^{\text{ID}} + \max\{r_{(v=1),d,t}^{\text{SR},\downarrow,*}, r_{(v=2),d,t}^{\text{SR},\downarrow,*}\} \leq \left(\frac{\bar{P}_{d,t}}{100}\right) p_{d,t}^*, \quad \forall k \in \mathcal{K}, \forall d \in \mathcal{D}, \forall t \geq \tau \quad (4.105)$$

$$\sum_{k=1}^{k-1} p_{k,d,t}^{\text{ID},*} + p_{k,d,t}^{\text{ID}} - \max\{r_{(v=1),d,t}^{\text{SR},\uparrow,*}, r_{(v=2),d,t}^{\text{SR},\uparrow,*}\} \leq \left(\frac{\underline{P}_{d,t}}{100}\right) p_{d,t}^*, \quad \forall k \in \mathcal{K}, \forall d \in \mathcal{D}, \forall t \geq \tau \quad (4.106)$$

$$\begin{aligned} & \left(p_{d,t}^* + \sum_{k=1}^{k-1} p_{k,d,t}^{\text{ID},*} + p_{k,d,t}^{\text{ID}} + \max\{r_{(v=1),d,t}^{\text{SR},\downarrow,*}, r_{(v=2),d,t}^{\text{SR},\downarrow,*}\} \right) \\ & - \left(p_{d,(t-1)}^* + \sum_{k=1}^{k-1} p_{k,d,(t-1)}^{\text{ID},*} + p_{k,d,(t-1)}^{\text{ID}} \right. \\ & \left. - \max\{r_{(v=1),d,(t-1)}^{\text{SR},\uparrow,*}, r_{(v=1),d,(t-1)}^{\text{SR},\uparrow,*}\} \right) \leq \bar{R}_d \Delta t, \\ & \forall k \in \mathcal{K}, \forall d \in \mathcal{D}, \forall t \geq \tau \end{aligned} \quad (4.107)$$

$$\begin{aligned} & \left(p_{d,(t-1)}^* + \sum_{k=1}^{k-1} p_{k,d,(t-1)}^{\text{ID},*} + p_{k,d,(t-1)}^{\text{ID}} + \max\{r_{(v=1),d,(t-1)}^{\text{SR},\downarrow,*}, r_{(v=2),d,(t-1)}^{\text{SR},\downarrow,*}\} \right) \\ & - \left(p_{d,t}^* + \sum_{k=1}^{k-1} p_{k,d,t}^{\text{ID},*} + p_{k,d,t}^{\text{ID}} - \max\{r_{(v=1),d,t}^{\text{SR},\uparrow,*}, r_{(v=1),d,t}^{\text{SR},\uparrow,*}\} \right) \leq \underline{R}_d \Delta t, \\ & \forall k \in \mathcal{K}, \forall d \in \mathcal{D}, \forall t \geq \tau \end{aligned} \quad (4.108)$$

$$\begin{aligned} \underline{E}_d \leq & \sum_{t=1}^{\tau-1} \left(p_{d,t}^* \Delta t + \sum_{k=1}^{k-1} p_{k,d,t}^{\text{ID},*} \Delta t - F^{\text{SR}} \max\{r_{(v=1),d,t}^{\text{SR},\uparrow,*}, r_{(v=2),d,t}^{\text{SR},\uparrow,*}\} \right) \\ & + \sum_{t=\tau}^T \left(p_{d,t}^* \Delta t + \sum_{k=1}^{k-1} (p_{k,d,t}^{\text{ID},*} + p_{k,d,t}^{\text{ID}}) \Delta t - F^{\text{SR}} \max\{r_{(v=1),d,t}^{\text{SR},\uparrow,*}, r_{(v=1),d,t}^{\text{SR},\uparrow,*}\} \right), \\ & \forall k \in \mathcal{K}, \forall d \in \mathcal{D} \end{aligned} \quad (4.109)$$

4.7 Energy Storage Systems

ESSs are a fundamental part of power systems, and as such, they have been around for over a century. By far, the most widespread ESS technology is the PHES, with nearly 200 GW of total capacity installed globally according to the Department of Energy (DoE) Global Energy Storage Database. However, similarly to conventional hydroelectric generation, PHESs have already been exploited to nearly the maximum in developed countries. This fact, together with the outstanding development of power converters, have led in recent years to the study, prototyping and installation of other energy storage technologies at a remarkably high pace. Among such converter-interfaced storage technologies, the most popular is the electrochemical BESSs. However, a broad variety of other technologies are also available, with different levels of maturity [1]. These include technologies based on ultracapacitors, flywheels, compressed-air, superconducting coils, flow batteries, thermal energy, and a large etcetera.

Although BESSs show a huge potential in improving the flexibility and reliability of power systems, they nevertheless also show important economic and technical limitations. Therefore, and as discussed in Section 2.1, BESSs are intentionally *left out of* the DVPP configuration. In the same vein, other converter-interfaced solutions that are *explicitly commissioned* for improving the competitiveness and reliability of ND-RESs are not considered in this work.

Consequently, in this WP, the only storage technologies that are considered are (i) already existing showing a *substantial* share in the global power system portfolio (i.e., PHESs, STUs with thermal storage), or (ii) going to be installed for other purposes and that, as by-product, can participate as a DVPP asset (i.e., V2G-EVs). Note that, at this stage of the project EVs are considered to be based on the G2V technology, and thus, they are modelled as a type of flexible demand. The possibility of considering V2G-EVs will be studied in subsequent Tasks.

Usually, large-scale ESSs (including PHES and BESS) do not “actively” participate in the different market pools seeking maximum profit on their own. Instead, such ESSs are usually regulated facilities operated by the system operator for the benefit of the market as a whole. In the context of POSYTYF, this implies that a comparison of the economic viability between DVPP- and BESS-based solutions should be performed from the system point of view, and not from the “device” perspective.

The equations that represent an ESS in the model core of the optimization algorithm are listed below. Note that ESSs can typically vary their active power generation and consumption faster than conventional generating units [21]. Thus, their ramping constraints are unbounded and not included in the model.

4.7.1 ESS Constraints in the DAM

The ESS formulation in the DAM is presented in (4.110)-(4.131). The constraints (4.110)-(4.113) limit the charging and discharging capability of ESS considering providing aFRR. Constraint (4.114)-(4.117) define the aFRR ramp capability of ESSs. The output power of ESS is assigned by (4.118). The final up/down aFRR provided in the SRM by the storage are calculated by (4.119) and (4.120). The energy level of ESS is related to its power by (4.121). Constraint (4.122) defines the self-discharge value of ESS. A specified amount of ESS's energy is assigned only to provide up and down reserve by (4.123)-(4.126). Constraint (4.123) limits this specified amount of energy considering the maximum up reserve is called on for all periods. Constraint (4.124) assures the worst case between states $v = 1$ and $v = 2$ when the up reserve is maximum. Constraints (4.125) and (4.126) are down reserve cases of (4.123) and (4.124). The energy of ESS is limited by (4.127) and (4.128) considering the value of energy assigned to provide the aFRR. The upper and lower

limits for the last period are assigned by (4.128) at specific value to energy not be completely depleted or to be full at the beginning of the next period. Constraint (4.129) assigns the possible values for the ESS's energy coefficient in the last period. The ESS degradation cost is defined in (4.130). The nature of binary variables is defined in (4.131).

$$p_{s,t}^+ + r_{v,s,t}^{SR,+,\downarrow} \leq \bar{p}_s^+ u_{s,t}, \quad \forall v \geq 1, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \quad (4.110)$$

$$\underline{p}_s^+ u_{s,t} \leq p_{s,t}^+ - r_{v,s,t}^{SR,+,\uparrow}, \quad \forall v \geq 1, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \quad (4.111)$$

$$p_{s,t}^- + r_{v,s,t}^{SR,-,\uparrow} \leq \bar{p}_s^-(1 - u_{s,t}), \quad \forall v \geq 1, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \quad (4.112)$$

$$\underline{p}_s^-(1 - u_{s,t}) \leq p_{s,t}^- - r_{v,s,t}^{SR,-,\downarrow}, \quad \forall v \geq 1, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \quad (4.113)$$

$$r_{v,s,t}^{SR,-,\uparrow} \leq T^{SR} \bar{R}_s^{SR} u_{v,s,t}^{SR,-}, \quad \forall v \geq 1, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \quad (4.114)$$

$$r_{v,s,t}^{SR,-,\downarrow} \leq T^{SR} \bar{R}_s^{SR} (1 - u_{v,s,t}^{SR,-}), \quad \forall v \geq 1, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \quad (4.115)$$

$$r_{v,s,t}^{SR,+,\downarrow} \leq T^{SR} \bar{R}_s^{SR} u_{v,s,t}^{SR,+}, \quad \forall v \geq 1, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \quad (4.116)$$

$$r_{v,s,t}^{SR,+,\uparrow} \leq T^{SR} \bar{R}_s^{SR} (1 - u_{v,s,t}^{SR,+}), \quad \forall v \geq 1, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \quad (4.117)$$

$$p_{s,t} = p_{s,t}^- - p_{s,t}^+, \quad \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \quad (4.118)$$

$$r_{v,s,t}^{SR,\uparrow} = r_{v,s,t}^{SR,-,\uparrow} + r_{v,s,t}^{SR,+,\uparrow}, \quad \forall v \geq 1, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \quad (4.119)$$

$$r_{v,s,t}^{SR,\downarrow} = r_{v,s,t}^{SR,-,\downarrow} + r_{v,s,t}^{SR,+,\downarrow}, \quad \forall v \geq 1, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \quad (4.120)$$

$$e_{s,t} = (1 - \gamma_s)(e_{s,(t-1)}) + p_{s,t}^+ \eta_s^+ \Delta t - \frac{p_{s,t}^- \Delta t}{\eta_s^-}, \quad \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \quad (4.121)$$

$$0 \leq \gamma_s \leq 100, \quad \forall s \in \mathcal{S} \quad (4.122)$$

$$\sum_{t \in \mathcal{T}} \left(F^{SR} \frac{r_{s,t}^{SR,\uparrow} \Delta t}{\eta_s^-} \right) \leq \sigma_s^{SR,\uparrow} (\bar{E}_s - \underline{E}_s), \quad \forall s \in \mathcal{S} \quad (4.123)$$

$$r_{v,s,t}^{SR,\uparrow} \leq r_{s,t}^{SR,\uparrow}, \quad \forall v \geq 1, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \quad (4.124)$$

$$\sum_{t \in \mathcal{T}} (F^{SR} r_{s,t}^{SR,\downarrow} \eta_s^+ \Delta t) \leq \sigma_s^{SR,\downarrow} (\bar{E}_s - \underline{E}_s), \quad \forall s \in \mathcal{S} \quad (4.125)$$

$$r_{v,s,t}^{SR,\downarrow} \leq r_{s,t}^{SR,\downarrow}, \quad \forall v \geq 1, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \quad (4.126)$$

$$\underline{E}_s + \sigma_s^{SR,\uparrow} (\bar{E}_s - \underline{E}_s) \leq e_{s,t} \leq \bar{E}_s - \sigma_s^{SR,\downarrow} (\bar{E}_s - \underline{E}_s), \quad \forall s \in \mathcal{S}, \forall t \leq T - 1 \quad (4.127)$$

$$\alpha_s (\underline{E}_s + \sigma_s^{SR,\uparrow} (\bar{E}_s - \underline{E}_s)) \leq e_{s,(t=T)} \leq \bar{\alpha}_s (\bar{E}_s - \sigma_s^{SR,\downarrow} (\bar{E}_s - \underline{E}_s)), \quad \forall s \in \mathcal{S} \quad (4.128)$$

$$0 \leq \alpha_s \leq \bar{\alpha}_s \leq 1, \quad \forall s \in \mathcal{S} \quad (4.129)$$

$$c_s^{\text{deg}} = \left| \frac{M_s}{100} \right| \frac{C_s}{\bar{E}_s} \sum_{t \in \mathcal{T}} p_{s,t}^- \Delta t, \quad \forall s \in \mathcal{S} \quad (4.130)$$

$$u_{s,t}, u_{v,s,t}^{SR,-}, u_{v,s,t}^{SR,+} \in \{0,1\}, \quad \forall v \geq 1, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \quad (4.131)$$

4.7.2 ESS Constraints in the SRM

The constraints of ESS in the SRM are formulated in this section. The differences with the DAM formulation are that the power of DAM is fixed, and the power of IDM1 is added in the constraint (4.118).

$$p_{s,t}^* + p_{(k=1),s,t}^{\text{ID}} = p_{s,t}^- - p_{s,t}^+, \quad \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \quad (4.132)$$

$$(4.110) - (4.117), (4.119) - (4.131) \quad (4.133)$$

4.7.3 ESS Constraints in the IDMs

The ESS equations (4.134)-(4.144) are written for each intra-day session period. The maximum amount of aFRR provided in SRM is used in (4.134)-(4.137) to define the charging and discharging capability of ESSs. The power produced by ESS is updated in (4.138) by considering the power of ESS in the DAM and the IDMs. The energy values assigned for up and down aFRR by variables $\sigma_s^{\text{SR},\uparrow}$ and $\sigma_s^{\text{SR},\downarrow}$ are fixed in the IDMs in (4.140) and (4.141).

$$p_{s,t}^+ + \max\{r_{(v=1),s,t}^{\text{SR},\downarrow,*}, r_{(v=2),s,t}^{\text{SR},\downarrow,*}\} \leq \bar{P}_s^+ u_{s,t}, \quad \forall s \in \mathcal{S}, \forall t \geq \tau \quad (4.134)$$

$$\bar{P}_s^+ u_{s,t} \leq p_{s,t}^+ - \max\{r_{(v=1),s,t}^{\text{SR},\uparrow,*}, r_{(v=2),s,t}^{\text{SR},\uparrow,*}\}, \quad \forall s \in \mathcal{S}, \forall t \geq \tau \quad (4.135)$$

$$p_{s,t}^- + \max\{r_{(v=1),s,t}^{\text{SR},\uparrow,*}, r_{(v=2),s,t}^{\text{SR},\uparrow,*}\} \leq \bar{P}_s^- (1 - u_{s,t}), \quad \forall s \in \mathcal{S}, \forall t \geq \tau \quad (4.136)$$

$$\bar{P}_s^- (1 - u_{s,t}) \leq p_{s,t}^- - \max\{r_{(v=1),s,t}^{\text{SR},\downarrow,*}, r_{(v=2),s,t}^{\text{SR},\downarrow,*}\}, \quad \forall s \in \mathcal{S}, \forall t \geq \tau \quad (4.137)$$

$$p_{s,t}^* + \sum_{k=1}^{k-1} p_{k,s,t}^{\text{ID},*} + p_{k,s,t}^{\text{ID}} = p_{s,t}^- - p_{s,t}^+, \quad \forall k \in \mathcal{K}, \forall s \in \mathcal{S}, \forall t \geq \tau \quad (4.138)$$

$$e_{s,t} = (1 - \gamma_s)(e_{s,(t-1)}) + p_{s,t}^+ \eta_s^+ \Delta t - \frac{p_{s,t}^- \Delta t}{\eta_s^-}, \quad \forall s \in \mathcal{S}, \forall t \geq \tau \quad (4.139)$$

$$\bar{E}_s + \sigma_s^{\text{SR},\uparrow,*} (\bar{E}_s - E_s) \leq e_{s,t} \leq \bar{E}_s - \sigma_s^{\text{SR},\downarrow,*} (\bar{E}_s - E_s), \quad \forall s \in \mathcal{S}, \forall \tau \leq t \leq T - 1 \quad (4.140)$$

$$\alpha_s (\bar{E}_s + \sigma_s^{\text{SR},\uparrow,*} (\bar{E}_s - E_s)) \leq e_{s,(t=T)} \leq \bar{\alpha}_s (\bar{E}_s - \sigma_s^{\text{SR},\downarrow,*} (\bar{E}_s - E_s)), \quad \forall s \in \mathcal{S} \quad (4.141)$$

$$0 \leq \alpha_s \leq \bar{\alpha}_s \leq 1, \quad \forall s \in \mathcal{S} \quad (4.142)$$

$$c_s^{\text{deg}} = \left| \frac{M_s}{100} \right| \frac{C_s}{\bar{E}_s} \sum_{t \in \tau} p_{s,t}^- \Delta t, \quad \forall s \in \mathcal{S} \quad (4.143)$$

$$u_{s,t} \in \{0,1\}, \quad \forall s \in \mathcal{S}, \forall t \geq \tau \quad (4.144)$$

4.8 Solar Thermal Units

STUs are synchronous generating plants that rely on a stochastic renewable source (solar irradiation). Additionally, they usually include storage capability for as much as 8 hours at full power capacity [22]. Moreover, conversion between thermal and electrical power that takes place in the Power Block (PB) of the STU needs to be appropriately formulated. For these reasons, STUs cannot be accurately represented by parametrizing any of the sets of constraints above, and they require a specific set in the DVPP model proposed in this work, which is formulated below [23].

4.8.1 STU Constraints in the DAM

The STU formulation in the DAM is presented in (4.145)-(4.176). The STU can provide up/down reserve by exploiting its thermal storage. Constraint (4.145) shows the bounds for power generation of the solar field. Constraints (4.146)-(4.149) limit the charging and discharging power of thermal storage by considering the provision of aFRR in the SRM. The maximum capability of STU's thermal storage to provide up and down reserve are defined in (4.150)-(4.153). The binary variables $u_{v,\theta,t}^{SR,-}$ and $u_{v,\theta,t}^{SR,+}$ do not allow both up and down reserve provision at the same time. Thermal power and reserve delivered to the STU power block are given in (4.154). The final up/down aFRR provided by the thermal storage are calculated by (4.155) and (4.156). The maximum and the minimum output power of the turbine are defined in (4.157) and (4.158). Constraints (4.159) and (4.160) define the commitment status of STUs. The electrical power output of STU by considering the provision of the aFRR is confined in (4.161).

The relation between energy and power of thermal storage is calculated in (4.162). A specified amount of thermal storage energy is assigned for the provision of up/down reserve by considering the worst condition of reserve provision in (4.163)-(4.166). The thermal energy of storage for the provision of power in the DAM is depicted in (4.167) and (4.168). Constraint (4.169) assigns the possible values for the thermal storage's energy coefficient in the last period. The minimum up and down time constraints for STUs in (4.170)-(4.175) are similar to those for D-RES. The parameters $N_{\theta}^{on} = \min\{T, (UT_{\theta} - UP_{\theta}^0)U_{\theta}^0\}$ and $N_{\theta}^{off} = \min\{T, (DT_{\theta} - DO_{\theta}^0)(1 - U_{\theta}^0)\}$ are changed accordingly for STUs. The nature of binary variables is shown in (4.176).

$$0 \leq p_{\theta,t}^{SF} \leq \hat{P}_{\theta,t}, \quad \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.145)$$

$$p_{\theta,t}^{+} + r_{v,\theta,t}^{STU,SR,+,\downarrow} \leq \hat{P}_{\theta,t} u_{\theta,t}^{+}, \quad \forall v \geq 1, \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.146)$$

$$p_{\theta,t}^{+} u_{\theta,t}^{+} \leq p_{\theta,t}^{+} - r_{v,\theta,t}^{STU,SR,+,\uparrow}, \quad \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.147)$$

$$p_{\theta,t}^{-} + r_{v,\theta,t}^{STU,SR,-,\uparrow} \leq \hat{P}_{\theta,t} (1 - u_{\theta,t}^{+}), \quad \forall v \geq 1, \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.148)$$

$$p_{\theta,t}^{-} (1 - u_{\theta,t}^{+}) \leq p_{\theta,t}^{-} - r_{v,\theta,t}^{STU,SR,-,\downarrow}, \quad \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.149)$$

$$r_{v,\theta,t}^{STU,SR,-,\uparrow} \leq T^{SR} \bar{R}_{\theta}^{SR} u_{v,\theta,t}^{SR,-}, \quad \forall v \geq 1, \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.150)$$

$$r_{v,\theta,t}^{STU,SR,-,\downarrow} \leq T^{SR} \bar{R}_{\theta}^{SR} (1 - u_{v,\theta,t}^{SR,-}), \quad \forall v \geq 1, \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.151)$$

$$r_{v,\theta,t}^{STU,SR,+,\downarrow} \leq T^{SR} \bar{R}_{\theta}^{SR} u_{v,\theta,t}^{SR,+}, \quad \forall v \geq 1, \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.152)$$

$$r_{v,\theta,t}^{STU,SR,+,\uparrow} \leq T^{SR} \bar{R}_{\theta}^{SR} (1 - u_{v,\theta,t}^{SR,+}), \quad \forall v \geq 1, \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.153)$$

$$p_{\theta,t}^{PB} + r_{v,\theta,t}^{PB,SR,\uparrow} - r_{v,\theta,t}^{PB,SR,\downarrow} = p_{\theta,t}^{SF} + p_{\theta,t}^{-} + r_{v,\theta,t}^{STU,SR,\uparrow} - p_{\theta,t}^{+} - r_{v,\theta,t}^{STU,SR,\downarrow} - K_{\theta} v_{\theta,t}^1 \bar{P}_{\theta}^{PB}, \quad \forall v \in \mathcal{V}, \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.154)$$

$$r_{v,\theta,t}^{STU,SR,\uparrow} = r_{v,\theta,t}^{STU,SR,+,\uparrow} + r_{v,\theta,t}^{STU,SR,-,\uparrow}, \quad \forall v \geq 1, \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.155)$$

$$r_{v,\theta,t}^{STU,SR,\downarrow} = r_{v,\theta,t}^{STU,SR,+,\downarrow} + r_{v,\theta,t}^{STU,SR,-,\downarrow}, \quad \forall v \geq 1, \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.156)$$

$$p_{\theta,t}^{PB} + r_{v,\theta,t}^{PB,SR,\uparrow} \leq \bar{P}_{\theta}^{PB} u_{\theta,t}, \quad \forall v \geq 1, \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.157)$$

$$p_{\theta,t}^{PB} u_{\theta,t} \leq p_{\theta,t}^{PB} - r_{v,\theta,t}^{PB,SR,\downarrow}, \quad \forall v \geq 1, \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.158)$$

$$u_{\theta,t} - u_{\theta,(t-1)} = v_{\theta,t}^1 - v_{\theta,t}^0, \quad \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.159)$$

$$v_{\theta,t}^1 + v_{\theta,t}^0 \leq 1, \quad \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.160)$$

$$p_{\theta,t} + r_{v,\theta,t}^{\text{SR},\uparrow} - r_{v,\theta,t}^{\text{SR},\downarrow} = \begin{cases} \eta_{\theta,(n=1)} \times 0 & \text{if } 0 \leq p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB},\text{SR},\uparrow} - r_{v,\theta,t}^{\text{PB},\text{SR},\downarrow} \leq p_{\theta,(n=1)}^{\text{PB}} = \underline{p}_{\theta}^{\text{PB}} \\ \eta_{\theta,(n=2)}(p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB},\text{SR},\uparrow} - r_{v,\theta,t}^{\text{PB},\text{SR},\downarrow}) & \text{if } p_{\theta,(n=1)}^{\text{PB}} \leq p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB},\text{SR},\uparrow} - r_{v,\theta,t}^{\text{PB},\text{SR},\downarrow} \leq p_{\theta,(n=2)}^{\text{PB}} \\ \eta_{\theta,(n=3)}(p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB},\text{SR},\uparrow} - r_{v,\theta,t}^{\text{PB},\text{SR},\downarrow}) & \text{if } p_{\theta,(n=2)}^{\text{PB}} \leq p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB},\text{SR},\uparrow} - r_{v,\theta,t}^{\text{PB},\text{SR},\downarrow} \leq p_{\theta,(n=3)}^{\text{PB}} \\ \eta_{\theta,(n=4)}(p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB},\text{SR},\uparrow} - r_{v,\theta,t}^{\text{PB},\text{SR},\downarrow}) & \text{if } p_{\theta,(n=3)}^{\text{PB}} \leq p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB},\text{SR},\uparrow} - r_{v,\theta,t}^{\text{PB},\text{SR},\downarrow} \leq p_{\theta,(n=4)}^{\text{PB}} \\ \eta_{\theta,(n=5)}(p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB},\text{SR},\uparrow} - r_{v,\theta,t}^{\text{PB},\text{SR},\downarrow}) & \text{if } p_{\theta,(n=4)}^{\text{PB}} \leq p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB},\text{SR},\uparrow} - r_{v,\theta,t}^{\text{PB},\text{SR},\downarrow} \leq p_{\theta,(n=5)}^{\text{PB}} \end{cases}, \quad (4.161)$$

$$\forall v \in \mathcal{V}, \forall \theta \in \Theta, \forall t \in \mathcal{T}$$

$$e_{\theta,t} = e_{\theta,(t-1)} + p_{\theta,t}^+ \eta_{\theta}^+ \Delta t - \frac{p_{\theta,t}^- \Delta t}{\eta_{\theta}^-}, \quad \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.162)$$

$$\sum_{t \in \mathcal{T}} \left(F^{\text{SR}} \frac{r_{\theta,t}^{\text{STU},\text{SR},\uparrow} \Delta t}{\eta_{\theta}^-} \right) \leq \sigma^{\text{SR},\uparrow} (\bar{E}_{\theta} - \underline{E}_{\theta}), \quad \forall \theta \in \Theta \quad (4.163)$$

$$r_{v,\theta,t}^{\text{STU},\text{SR},\uparrow} \leq r_{\theta,t}^{\text{STU},\text{SR},\uparrow}, \quad \forall v \geq 1, \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.164)$$

$$\sum_{t \in \mathcal{T}} (F^{\text{SR}} r_{\theta,t}^{\text{STU},\text{SR},\downarrow} \eta_{\theta}^+ \Delta t) \leq \sigma^{\text{SR},\downarrow} (\bar{E}_{\theta} - \underline{E}_{\theta}), \quad \forall \theta \in \Theta \quad (4.165)$$

$$r_{v,\theta,t}^{\text{SR},\downarrow} \leq r_{\theta,t}^{\text{SR},\downarrow}, \quad \forall v \geq 1, \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.166)$$

$$\underline{E}_{\theta} + \sigma_{\theta}^{\text{SR},\downarrow} (\bar{E}_{\theta} - \underline{E}_{\theta}) \leq e_{\theta,t} \leq \bar{E}_{\theta} - \sigma_{\theta}^{\text{SR},\downarrow} (\bar{E}_{\theta} - \underline{E}_{\theta}), \quad \forall \theta \in \Theta, \forall t \leq T-1 \quad (4.167)$$

$$\alpha_{\theta} (\underline{E}_{\theta} + \sigma_{\theta}^{\text{SR},\downarrow} (\bar{E}_{\theta} - \underline{E}_{\theta})) \leq e_{\theta,(t=T)} \leq \bar{\alpha}_{\theta} (\bar{E}_{\theta} - \sigma_{\theta}^{\text{SR},\downarrow} (\bar{E}_{\theta} - \underline{E}_{\theta})), \quad \forall \theta \in \Theta \quad (4.168)$$

$$0 \leq \alpha_{\theta} \leq \bar{\alpha}_{\theta} \leq 1, \quad \forall \theta \in \Theta \quad (4.169)$$

$$\sum_{t=1}^{N_{\theta}^{\text{on}}} (1 - u_{\theta,t}) = 0, \quad \forall \theta \in \Theta \quad (4.170)$$

$$UT_{\theta} (u_{\theta,t} - u_{\theta,(t-1)}) \leq \sum_{t'=t}^{t+UT_{\theta}-1} u_{\theta,t'}, \quad \forall \theta \in \Theta, \forall t = N_{\theta}^{\text{on}} + 1, \dots, T - UT_{\theta} + 1 \quad (4.171)$$

$$0 \leq \sum_{t'=t}^T \{u_{\theta,t'} - (u_{\theta,t} - u_{\theta,(t-1)})\}, \quad \forall \theta \in \Theta, \forall t = T - UT_{\theta} + 2, \dots, T \quad (4.172)$$

$$\sum_{t=1}^{N_{\theta}^{\text{off}}} u_{\theta,t} = 0, \quad \forall \theta \in \Theta \quad (4.173)$$

$$DT_{\theta} (u_{\theta,(t-1)} - u_{\theta,t}) \leq \sum_{t'=t}^{t+DT_{\theta}-1} (1 - u_{\theta,t'}), \quad \forall \theta \in \Theta, \forall t = N_{\theta}^{\text{off}} + 1, \dots, T - DT_{\theta} + 1 \quad (4.174)$$

$$0 \leq \sum_{t'=t}^T \{1 - u_{\theta,t'} - (u_{\theta,(t-1)} - u_{\theta,t})\}, \quad \forall \theta \in \Theta, \forall t = T - DT_{\theta} + 2, \dots, T \quad (4.175)$$

$$u_{\theta,t}, u_{\theta,t}^+, u_{v,\theta,t}^{\text{SR},+}, u_{v,\theta,t}^{\text{SR},-}, v_{\theta,t}^1, v_{\theta,t}^0 \in \{0,1\}, \quad \forall v \geq 1, \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.176)$$

4.8.2 STU Constraints in the SRM

The electrical output power of STU in the SRM is updated by considering the STU power change in the IDM1 according to (4.177). Other constraints are like the DAM.

$$p_{\theta,t}^* + p_{(k=1),\theta,t}^{\text{ID}} + r_{v,\theta,t}^{\text{SR},\uparrow} - r_{v,\theta,t}^{\text{SR},\downarrow} = \begin{cases} \eta_{\theta,(n=1)} \times 0 & \text{if } 0 \leq p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow} - r_{v,\theta,t}^{\text{PB,SR},\downarrow} \leq P_{\theta,(n=1)}^{\text{PB}} \\ \eta_{\theta,(n=2)}(p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow} - r_{v,\theta,t}^{\text{PB,SR},\downarrow}) & \text{if } P_{\theta,(n=1)}^{\text{PB}} \leq p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow} - r_{v,\theta,t}^{\text{PB,SR},\downarrow} \leq P_{\theta,(n=2)}^{\text{PB}} \\ \eta_{\theta,(n=3)}(p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow} - r_{v,\theta,t}^{\text{PB,SR},\downarrow}) & \text{if } P_{\theta,(n=2)}^{\text{PB}} \leq p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow} - r_{v,\theta,t}^{\text{PB,SR},\downarrow} \leq P_{\theta,(n=3)}^{\text{PB}} \\ \eta_{\theta,(n=4)}(p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow} - r_{v,\theta,t}^{\text{PB,SR},\downarrow}) & \text{if } P_{\theta,(n=3)}^{\text{PB}} \leq p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow} - r_{v,\theta,t}^{\text{PB,SR},\downarrow} \leq P_{\theta,(n=4)}^{\text{PB}} \\ \eta_{\theta,(n=5)}(p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow} - r_{v,\theta,t}^{\text{PB,SR},\downarrow}) & \text{if } P_{\theta,(n=4)}^{\text{PB}} \leq p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow} - r_{v,\theta,t}^{\text{PB,SR},\downarrow} \leq P_{\theta,(n=5)}^{\text{PB}} \end{cases}, \quad (4.177)$$

$$\forall v \in \mathcal{V}, \forall \theta \in \Theta, \forall t \in \mathcal{T}$$

$$(4.145) - (4.160), (4.162) - (4.176) \quad (4.178)$$

4.8.3 STU Constraints in the IDMs

The STU constraints in the IDMs are defined in (4.179)-(4.200). The time span for each session of IDM is considered in the formulation. Besides, the output power of STU is updated based on the DAM output power of STU, the maximum reserve provision in the SRM, and the power change in the previous IDM sessions in (4.189). The minimum up and down time in (4.194)-(4.199) are changed by considering each IDM session's beginning. Therefore, the parameters $N_{k,\theta}^{\text{on}} = \min\{T-\tau, (UT_{\theta} - UP_{k,\theta}^0)U_{k,\theta}^0\}$ and $N_{k,\theta}^{\text{off}} = \min\{T-\tau, (DT_{\theta} - DO_{k,\theta}^0)(1-U_{k,\theta}^0)\}$ are modified accordingly.

$$0 \leq p_{\theta,t}^{\text{SF}} \leq \hat{P}_{\theta,t}, \quad \forall \theta \in \Theta, \forall t \geq \tau \quad (4.179)$$

$$p_{\theta,t}^+ + \max\{r_{(v=1),\theta,t}^{\text{STU,SR},+,\downarrow}, r_{(v=2),\theta,t}^{\text{STU,SR},+,\downarrow}\} \leq \hat{P}_{\theta,t} u_{\theta,t}^+, \quad \forall \theta \in \Theta, \forall t \geq \tau \quad (4.180)$$

$$P_{\theta}^+ u_{\theta,t}^+ \leq p_{\theta,t}^+ - \max\{r_{(v=1),\theta,t}^{\text{STU,SR},+,\uparrow}, r_{(v=2),\theta,t}^{\text{STU,SR},+,\uparrow}\}, \quad \forall \theta \in \Theta, \forall t \geq \tau \quad (4.181)$$

$$p_{\theta,t}^- + \max\{r_{(v=1),\theta,t}^{\text{STU,SR},-,\uparrow}, r_{(v=2),\theta,t}^{\text{STU,SR},-,\uparrow}\} \leq \hat{P}_{\theta,t} (1 - u_{\theta,t}^+), \quad \forall v \geq 1, \forall \theta \in \Theta, \forall t \geq \tau \quad (4.182)$$

$$P_{\theta}^- (1 - u_{\theta,t}^+) \leq p_{\theta,t}^- - \max\{r_{(v=1),\theta,t}^{\text{STU,SR},-,\downarrow}, r_{(v=2),\theta,t}^{\text{STU,SR},-,\downarrow}\}, \quad \forall \theta \in \Theta, \forall t \geq \tau \quad (4.183)$$

$$p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow,*} - r_{v,\theta,t}^{\text{PB,SR},\downarrow,*} = p_{\theta,t}^{\text{SF}} + p_{\theta,t}^- + r_{v,\theta,t}^{\text{STU,SR},\uparrow,*} - p_{\theta,t}^+ - r_{v,\theta,t}^{\text{STU,SR},\downarrow,*} - K_{\theta} v_{\theta,t}^1 \bar{P}_{\theta}^{\text{PB}}, \quad \forall v \in \mathcal{V}, \forall \theta \in \Theta, \forall t \geq \tau \quad (4.184)$$

$$p_{\theta,t}^{\text{PB}} + \max\{r_{(v=1),\theta,t}^{\text{PB,SR},\uparrow,*}, r_{(v=2),\theta,t}^{\text{PB,SR},\uparrow,*}\} \leq \bar{P}_{\theta}^{\text{PB}} u_{\theta,t}, \quad \forall \theta \in \Theta, \forall t \geq \tau \quad (4.185)$$

$$P_{\theta}^{\text{PB}} u_{\theta,t} \leq p_{\theta,t}^{\text{PB}} - \max\{r_{(v=1),\theta,t}^{\text{PB,SR},\downarrow,*}, r_{(v=2),\theta,t}^{\text{PB,SR},\downarrow,*}\}, \quad \forall \theta \in \Theta, \forall t \geq \tau \quad (4.186)$$

$$u_{\theta,t} - u_{\theta,(t-1)} = v_{\theta,t}^1 - v_{\theta,t}^0, \quad \forall \theta \in \Theta, \forall t \geq \tau \quad (4.187)$$

$$v_{\theta,t}^1 + v_{\theta,t}^0 \leq 1, \quad \forall \theta \in \Theta, \forall t \geq \tau \quad (4.188)$$

$$\begin{aligned}
 & p_{\theta,t}^* + \sum_{k=1}^{k-1} p_{k,\theta,t}^{\text{ID},*} + p_{k,\theta,t}^{\text{ID}} + r_{v,\theta,t}^{\text{SR},\uparrow} - r_{v,\theta,t}^{\text{SR},\downarrow} \\
 & = \left\{ \begin{array}{ll} \eta_{\theta,(n=1)} \times 0 & \text{if } 0 \leq p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow,*} - r_{v,\theta,t}^{\text{PB,SR},\downarrow,*} \leq P_{\theta,(n=1)}^{\text{PB}} \\ \eta_{\theta,(n=2)} (p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow,*} - r_{v,\theta,t}^{\text{PB,SR},\downarrow,*}) & \text{if } P_{\theta,(n=1)}^{\text{PB}} \leq p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow,*} - r_{v,\theta,t}^{\text{PB,SR},\downarrow,*} \leq P_{\theta,(n=2)}^{\text{PB}} \\ \eta_{\theta,(n=3)} (p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow,*} - r_{v,\theta,t}^{\text{PB,SR},\downarrow,*}) & \text{if } P_{\theta,(n=2)}^{\text{PB}} \leq p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow,*} - r_{v,\theta,t}^{\text{PB,SR},\downarrow,*} \leq P_{\theta,(n=3)}^{\text{PB}} \\ \eta_{\theta,(n=4)} (p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow,*} - r_{v,\theta,t}^{\text{PB,SR},\downarrow,*}) & \text{if } P_{\theta,(n=3)}^{\text{PB}} \leq p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow,*} - r_{v,\theta,t}^{\text{PB,SR},\downarrow,*} \leq P_{\theta,(n=4)}^{\text{PB}} \\ \eta_{\theta,(n=5)} (p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow,*} - r_{v,\theta,t}^{\text{PB,SR},\downarrow,*}) & \text{if } P_{\theta,(n=4)}^{\text{PB}} \leq p_{\theta,t}^{\text{PB}} + r_{v,\theta,t}^{\text{PB,SR},\uparrow,*} - r_{v,\theta,t}^{\text{PB,SR},\downarrow,*} \leq P_{\theta,(n=5)}^{\text{PB}} \end{array} \right\}, \quad (4.189)
 \end{aligned}$$

$$\forall k \in \mathcal{K}, \forall v \in \mathcal{V}, \forall \theta \in \Theta, \forall t \geq \tau$$

$$e_{\theta,t} = e_{\theta,(t-1)} + p_{\theta,t}^+ \eta_{\theta}^+ \Delta t - \frac{p_{\theta,t}^- \Delta t}{\eta_{\theta}^-}, \quad \forall \theta \in \Theta, \forall t \geq \tau \quad (4.190)$$

$$\bar{E}_{\theta} + \sigma_{\theta}^{\text{SR},\downarrow,*} (\bar{E}_{\theta} - \underline{E}_{\theta}) \leq e_{\theta,t} \leq \bar{E}_{\theta} - \sigma_{\theta}^{\text{SR},\downarrow,*} (\bar{E}_{\theta} - \underline{E}_{\theta}), \quad \forall \theta \in \Theta, \forall \tau \leq t \leq T-1 \quad (4.191)$$

$$\alpha_{\theta} (\bar{E}_{\theta} + \sigma_{\theta}^{\text{SR},\downarrow,*} (\bar{E}_{\theta} - \underline{E}_{\theta})) \leq e_{\theta,(t=T)} \leq \bar{\alpha}_{\theta} (\bar{E}_{\theta} - \sigma_{\theta}^{\text{SR},\downarrow,*} (\bar{E}_{\theta} - \underline{E}_{\theta})), \quad \forall \theta \in \Theta \quad (4.192)$$

$$0 \leq \alpha_{\theta} \leq \bar{\alpha}_{\theta} \leq 1, \quad \forall \theta \in \Theta \quad (4.193)$$

$$\sum_{t=\tau}^{\tau-1+N_{k,\theta}^{\text{on}}} (1 - u_{\theta,t}) = 0, \quad \forall k \in \mathcal{K}, \forall \theta \in \Theta \quad (4.194)$$

$$UT_{\theta} (u_{\theta,t} - u_{\theta,(t-1)}) \leq \sum_{t'=\tau}^{t+UT_{\theta}-1} u_{\theta,t'}, \quad \forall k \in \mathcal{K}, \forall \theta \in \Theta, \forall t = \tau + N_{k,\theta}^{\text{on}}, \dots, T - UT_{\theta} + 1 \quad (4.195)$$

$$0 \leq \sum_{t'=t}^T \{u_{\theta,t'} - (u_{\theta,t} - u_{\theta,(t-1)})\}, \quad \forall \theta \in \Theta, \forall t = T - UT_{\theta} + 2, \dots, T \quad (4.196)$$

$$\sum_{t=1}^{\tau-1+N_{k,\theta}^{\text{off}}} u_{\theta,t} = 0, \quad \forall k \in \mathcal{K}, \forall \theta \in \Theta \quad (4.197)$$

$$\begin{aligned}
 DT_{\theta} (u_{\theta,(t-1)} - u_{\theta,t}) & \leq \sum_{t'=\tau}^{t+DT_{\theta}-1} (1 - u_{\theta,t'}), \\
 & \forall k \in \mathcal{K}, \forall \theta \in \Theta, \forall t = \tau + N_{k,\theta}^{\text{off}}, \dots, T - DT_{\theta} + 1
 \end{aligned} \quad (4.198)$$

$$0 \leq \sum_{t'=t}^T \{1 - u_{\theta,t'} - (u_{\theta,(t-1)} - u_{\theta,t})\}, \quad \forall \theta \in \Theta, \forall t = T - DT_{\theta} + 2, \dots, T \quad (4.199)$$

$$u_{\theta,t}, u_{\theta,t}^+, u_{v,\theta,t}^{\text{SR},+}, u_{v,\theta,t}^{\text{SR},-}, v_{\theta,t}^1, v_{\theta,t}^0 \in \{0,1\}, \quad \forall v \geq 1, \forall \theta \in \Theta, \forall t \geq \tau \quad (4.200)$$

4.8.4 SOS-2 Formulation for Piece-Wise Linear Functions

The Special Ordered Set of type 2 (SOS-2) constraints (4.201)-(4.206) are written to model the piece-wise function (4.161) in a linear form [24].

$$p_{\theta,t}^{\text{PB}} = \sum_{n \in \mathcal{N}} P_{\theta,n}^{\text{PB}} x_{\theta,t,n}, \quad \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.201)$$

$$\sum_{n \in \mathcal{N}} x_{\theta,t,n} = 1, \quad \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.202)$$

$$p_{\theta,t} = \sum_{n \in \mathcal{N}} \eta_{\theta,n} P_{\theta,n}^{\text{PB}} x_{\theta,t,n}, \quad \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.203)$$

$$x_{\theta,t,n} \leq y_{\theta,t,n}, \quad \forall \theta \in \Theta, \forall t \in \mathcal{T}, \forall n \in \mathcal{N} \quad (4.204)$$

$$\sum_{n \in \mathcal{N}} y_{\theta,t,n} \leq 2, \quad \forall \theta \in \Theta, \forall t \in \mathcal{T} \quad (4.205)$$

$$y_{\theta,t,n} + y_{\theta,t,n'} \leq 1, \quad \forall \theta \in \Theta, \forall t \in \mathcal{T}, n \leq |\mathcal{N}| - 2, n' \geq n + 2 \quad (4.206)$$

5 Parameter Characterization

5.1 DVPP Model Parameters

A crucial aspect of any model that represents a *real-life* system is the proper characterization of the parameters that define such a system. It is evident that, for the same set of equations that compose a model, using different parameters will lead to different results of the system behavior. Moreover, some models naturally show high sensitivities to parameter variations, meaning that relatively small differences in system parameters can lead to substantially large differences in system dynamic behavior in case of dynamic system models, or optimal values of the objective function and variables of an optimization system model.

In the context of the model that is developed in this WP, the task of properly characterizing the model parameters is remarkably challenging, mainly due to (i) the large number of parameters that need to be defined, and (ii) the highly uncertain nature of some of such parameters.

Table 5-1 collects an assortment of the parameters of the DVPP model that need to be defined. They are characterized based on their deterministic (fixed) or uncertain nature. Note that the list of parameters provided below is but a preliminary selection based on the stage of development of the model at the time of writing this report. It is expected that such a list will be, on one hand, extended with other parameters arising from the inclusion of new functionalities to the model core, and on the other hand, reduced by removing the dependency of the model on parameters whose impact in the solution of the algorithm is found to be negligible based on simulation results.

From the parameters listed in Table 5-1, those related to the D-RESs and the network are usually well-known and relatively easy to characterize. Similarly, for mature ESS technologies such as the PHES and the BESS, their models can be easily parametrized.

Demand technical parameters are, for the most part, deterministic and well-known. However, demand parameters that depend on the behavior of the consumers, e.g., the consumption profile of the component of the load that is not flexible, and the charging profile of G2V-EVs, include a level of uncertainty that, in principle, is difficult to predict. Although such uncertainties are not considered in the model core presented in this document, their proper characterization will be required for futures stages of the model development.

The stochasticity and uncertainty of the renewable source profiles such as wind speed and sun irradiation are the main drawbacks of ND-RESs that limit their competitiveness compared to D-RESs. Despite being a field of research for several decades, prediction of weather conditions and, thus, of renewable source profiles is still a remarkably challenging task. Although today's predictions show relatively high accuracy, uncertainties are still inherent, especially as the time horizon extends. Therefore, a proper characterization of the uncertainties related to the available power production of ND-RESs is crucial for the work conducted in this WP.

The last source of uncertainties that is relevant for the model presented in this document regards the different markets in which the DVPP can participate. In auction-based electricity markets, where producers and consumers submit offers and bids, respectively, the final price is only known after the market clearance. As a consequence, at the time of submitting the offers/bids, the producers/consumers need to predict the final price in order to be able to submit an optimal offer/bid that maximizes/minimizes their respective revenues/costs. Therefore, market price characterization is also essential for the purposes of the model

developed. The model presented in Chapter 4 considers uncertainties of the DAM, the IDM and the SRM. Additional functionalities of such a model will consider the participation of the DVPP in other ASMs, and thus their respective prices will also be properly characterized.

Table 5-1 Parameters of the DVPP optimization algorithm

Device/Tool	Parameter	Nature
D-RES	Shut-down cost	Deterministic
	Start-up cost	Deterministic
	Variable production cost	Deterministic
	Minimum power production	Deterministic
	Maximum power production	Deterministic
	Down ramping limit	Deterministic
	Up ramping limit	Deterministic
	Shut-down ramping limit	Deterministic
	Start-up ramping limit	Deterministic
Demand	Minimum energy consumption throughout the planning horizon	Deterministic
	Lower bound of the power consumption	Deterministic
	Upper bound of the power consumption	Deterministic
	Down ramping limit	Deterministic
	Up ramping limit	Deterministic
	Non-regulated load profile	Uncertain
	EV charging profile	Uncertain
ND-RES	Available production level	Uncertain
ESS	Lower bound of the energy stored	Deterministic
	Upper bound of the energy stored	Deterministic
	Charging capacity	Deterministic
	Discharging capacity	Deterministic
	Charging efficiency	Deterministic
	Discharging efficiency	Deterministic
	Self-discharge coefficient	Deterministic
	Degradation coefficient	Deterministic
Market	DAM energy price	Uncertain
	IDM energy price	Uncertain
	ASM energy price	Uncertain
	Time horizon	Deterministic
	Time periods	Deterministic
Network	Line susceptance	Deterministic
	Line capacity	Deterministic
	Line reactance	Deterministic
	Maximum power that can be traded with the main grid at connection buses	Deterministic

5.2 Modelling Uncertainties

The DVPP model presented in this document includes a set of parameters that are characterized by uncertainties that need to be considered in the model as identified in Table 5-1, namely:

- i. Available production level of the ND-RESs
- ii. Energy prices of the DAM
- iii. Energy prices of the IDM
- iv. Load consumption
- v. EV charging profile

The inclusion of uncertainties in optimization algorithms has been an intense research topic for some decades, and as a consequence, a rich literature can be found with different approaches to deal with parameter uncertainty.

In this WP, the so-called “Robust Optimization (RO)” will be implemented [25], [26], [27], [28]. In the RO, uncertain parameters are characterized by a “main”, most probable value, which can vary within an interval delimited by some, usually symmetric, upper and lower *confidence* bounds. For instance, the available power production of the ND-RES r at a time period t , i.e., $P_{r,t}$, will be defined by a main or nominal value, $\tilde{P}_{r,t}$, and confidence bounds $\pm \hat{P}_{r,t}$, as follows:

$$P_{r,t} \in [\tilde{P}_{r,t} - \hat{P}_{r,t}, \tilde{P}_{r,t} + \hat{P}_{r,t}], \quad \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \quad (5.1)$$

$$\hat{P}_{r,t} \geq 0, \quad \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \quad (5.2)$$

Similar expressions can be obtained for the DAM and IDM prices, namely λ_t^{DA} and λ_t^{ID} , respectively. More details about the RO can be found in Appendix B.

Therefore, assuming that one intends to obtain the optimal schedule of a DVPP participating in the DAM and that includes a wind power plant, it will be required that the wind speed profile is predicted for the next day, i.e., for a time horizon of 24 hours, in 24 intervals of 1 hour each. For each of such 24 intervals it is required to define the nominal wind speed value, i.e., the predicted value of the wind at each period, and the confidence bounds, i.e., the maximum absolute variation of such nominal value expected. This is graphically illustrated in Figure 5-1.

Note that all parameters characterized by uncertainty discussed so far show also a dependency on the time period $t \in \mathcal{T}$.⁸ This implies that, to feed the optimization algorithm described in this document, it is required to provide the time series of the predicted nominal values and confidence bounds for each time period. Moreover, if the DVPP participates in the IDM and/or ASM, updates of the predictions of the uncertain profiles need to be also generated and fed into the algorithm prior to the intra-day time periods of such markets.

⁸ Note also that most of the deterministic parameters shown in Table 5-1 are also fixed in time, i.e., they are equal for all time periods.

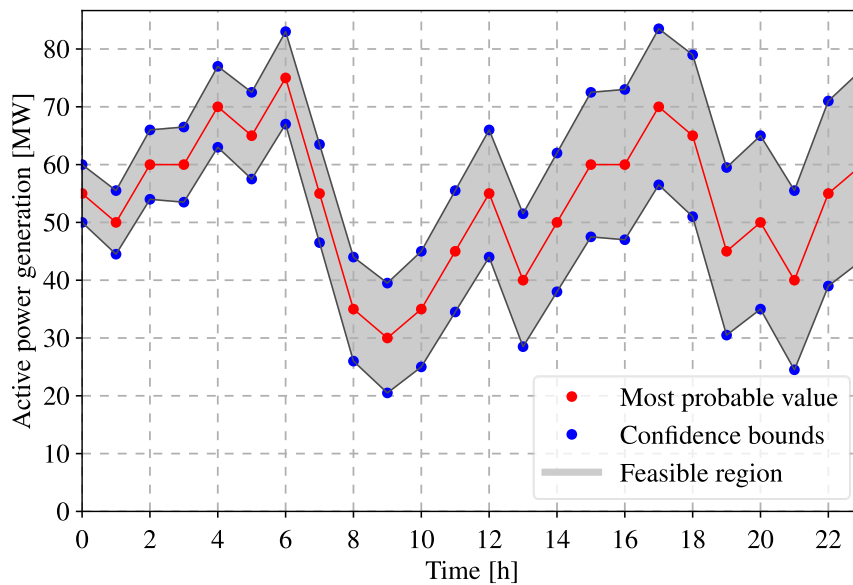


Figure 5-1 Graphical representation of the predicted nominal value and confidence bounds of the wind speed at a generic location.

For the sake of example, let assume that a DVPP with a wind power plant participates in the DAM and in the IDM. The DAM comprises one time horizon of 24 hours, divided into 24 segments of one hour each. Let also assume that the IDM comprises four time horizons in a single day, and distributed as illustrated in Figure 5-2. The DAM clears at noon the day before the market schedule realization. The IDM clears one hour before each of the starting time of the four market windows in Figure 5-2.

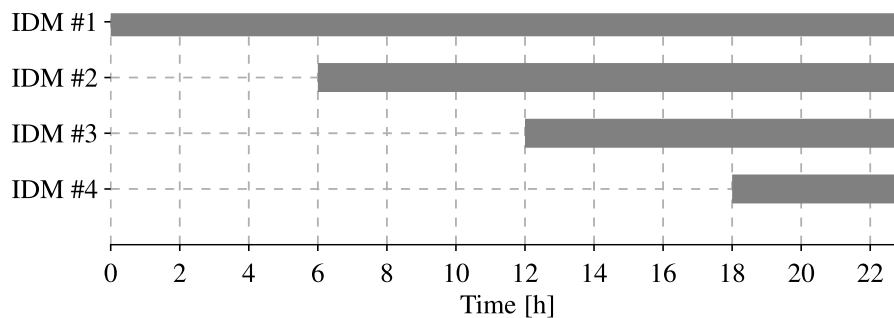


Figure 5-2 Illustrative example of daily IDMs sequence.

In the example above, the prediction of the DAM prices (24 nominal values and 24 confidence bounds, assuming a symmetric feasible region) needs to be calculated in a daily basis and fed into the optimization algorithm before the DAM market clearance, i.e., before noon the day before the schedule realization.

On the other hand, the prediction of the IDM prices needs to be calculated before the clearance of each of the four market windows, based on the updates of the ND-RES uncertain profiles that need also to be forecasted prior such clearances. For each of the IDM windows, only the forward periods until the end of the current day are required. For instance, in the example above, predictions for the next 24 periods need to be provided for the first IDM window (IDM #1), whereas for IDM #2, #3 and #4, only the next 18, 12 and 6 periods need to be forecasted, respectively. Note also that, in this example, offers/bids for the DAM for the next day are also submitted before the first period of the IDM #3, not necessarily simultaneously.

Other requirements for parametrizing the DVPP model discussed in this document are listed below.

1. The robustness and performance of the optimization algorithm developed in this task will be exhaustively analyzed in futures stages of the project. With this aim, a broad set of scenarios is required, not only in the sense of different DVPP configurations and applications, but also in the sense of weather conditions and market price variations. In this regard, predictions and realizations of the different uncertain profiles discussed in this Section need to be available for different scenarios such as:
 - a. low and high variability of prices and ND-RES profiles,
 - b. before and during the first confinement due to the COVID-19 outbreak,
 - c. low and high expected estimation errors of the predictions, and
 - d. ND-RESs installed within the same geographical region, and from different, geographically distributed regions.
2. The RO requires that the uncertain parameters of the algorithm are uncorrelated, i.e., variability of each parameter is independent from the others. In this regard, historical data of prices, ND-RES generation and demand consumptions is used to determine the correlation among profiles. Such dependence is defined through the *correlation coefficient*, $\rho_{a,b}$, which takes values within the interval $\rho_{a,b} \in (-1, 1)$ such that the two parameters a and b show perfect linear correlation if $\rho_{a,b} = 1$ (increasing) or $\rho_{a,b} = -1$ (decreasing), and no correlation if $\rho_{a,b} = 0$.

For instance, qualitatively, it can be assumed that the prices of the DAM and IDM are highly correlated, i.e., $|\rho_{\lambda^{\text{DAM}}, \lambda^{\text{ID}}}| \lesssim 1$, i.e., IDM prices, generally, do not differ substantially from DAM prices. Similarly, the correlation between market prices and the available generation of ND-RESs of relatively small capacity can be assumed to be negligible, i.e., $|\rho_{\lambda^{\text{DAM}}, p_r}| \gtrsim 0$, i.e., variations in the generation of a small ND-RES plant do not have a visible impact on the market prices. However, there are several of other correlations that cannot be known a priori. Moreover, all correlations need to be determined quantitatively. With this information, it would be possible to reformulate the model such that the correlations between uncertain parameters are *removed*.

3. The resolution of the data is also a crucial factor in the formulation of the optimization algorithm and the model. The optimal DVPP schedule for the DAM is usually calculated considering a set $\mathcal{T}$ of 24 periods t of 1 hour of duration. However, this is not the case for the IDMs and ASMs, which can consider time periods of 15 minutes and even shorter. To help ensure an optimal solution of the algorithm for the DVPP schedule, the predictions of the uncertain data should have a resolution of, at least, the smallest time period of the problem to be solved.
4. To duly analyze the practicality and viability of the DVPP solutions, they will be comprehensively compared with solutions based on electrochemical BESSs. To this aim, accurate data pertaining to BESSs are essential. Such data comprises technical parameters (power and energy capacities, efficiencies, self-discharge coefficients, etc.) and economic parameters (capital and variable costs, incentives, Levelized Cost of Storage, etc.).

5.3 Prices

The time horizon and the associated resolutions for the different markets have to be considered when forecasting prices associated with these different markets. While the DAM uses an hourly resolution, shorter time spans are utilized especially in the ASMs. Considering for instance the Spanish case, which is the one considered in the illustrative examples and preliminary results presented in Chapter 0, a historical dataset is provided by the market operator in Spain (OMIE) and the TSO, REE, through its information system (e-sios)⁹.

In order to obtain the prices used for the examples in Chapter 0, descriptive analysis was initially carried out. Subsequently, simple tools for making inferences for future outcomes were then utilized for generating price forecasts. For instance, for the 10th of March, 2014 which is a clear day, historical time series data for similar days in the past were obtained. Also, prices for all days leading up to that particular date were acquired. Analyzing these sets of data gave the average value (mean), the spread (standard deviation) and also the correlation of the prices with respect to the time of day. Thereafter, using regression, the forecasted price of the exact day (10/03/2014) was obtained with some level of confidence. The same idea was utilized for generating price forecasts for other illustrative examples. Figure 5-3 shows the DAM marginal price time series data for Jan 2010 – Dec 2013 acquired from e-sios price analysis webpage. Time series for intraday market price indicators were also obtained from the website and analyzed appropriately.

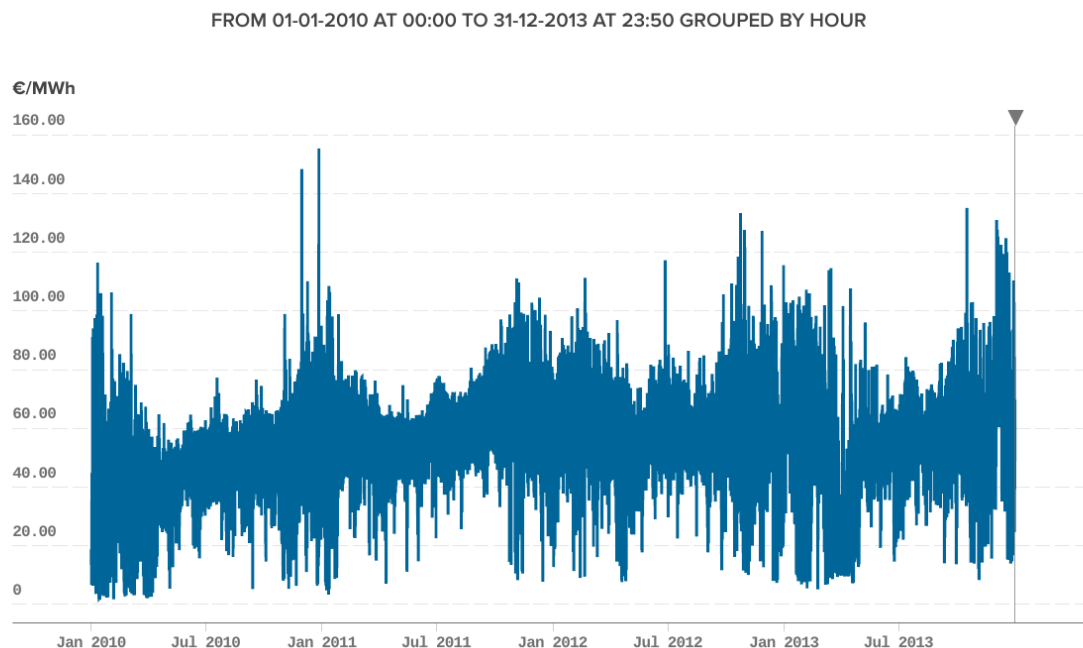


Figure 5-3 Time series data for DAM marginal prices

⁹ <https://www.esios.ree.es/en/analysis/>

5.4 Renewable Generation

Inclusion of renewable energy systems in DVPPs is not trivial due to their intermittency which generally pose operation challenges. Forecasts are generally not equal to real-time observations, and DVPP management activities will include giving trade offers well before power delivery. In a DAM scenario for example, this will be about 12 hours before the first period of energy delivery and 36 hours before the final energy delivery. Thus, management of the discrepancies between forecasts and real-time realization is also an important aspect of the DVPP manager's duties. In this WP, wind and solar power are the two primary renewable generation sources considered.

Some clarifications should be made on these renewable generation units in terms of differences in forecasts. For daily solar irradiation (which solar power depends on), they generally span about half of the day (more in summer periods, less in winter periods), and thus their forecasts also follow that trend. This is in contrast to that of wind profile forecasts which span the 24 hours of a 24-hour resolution day. Thus, methodologies and/or considerations for the forecasts need to be chosen appropriately.

With respect to solar power plants, project partner CIEMAT is working on using time-windowed solar radiation profiles for assessing the uncertainty of solar generation forecasts. In modelling output forecasts for solar generation, reliance is generally made on real-time weather forecasts of the direct normal irradiance (DNI) of the solar plant's location. Additionally, the forecasts need to be made in synchronization with other factors. The most important being the periods when production offers are made in the energy markets because simulation on solar irradiation is time-sensitive. The forecasting hours selected were thus made to coincide with the offer submission periods of the energy markets the DVPP is expected to participate. Let us analyze how forecast for the submission of DAM bids is done.

Considering that the DAM closes at 12:00 the day (D) before energy delivery, thus, forecasting hour would be D-13 (11:00) i.e., 13 hours before the first delivery of the offered energy. This chosen period gives ample time for submission of bids and also make the period close enough for a high level of confidence on the forecasts. After the appropriate time is chosen, a number (n) of solar radiation profiles are generated from DNI data. The generation of the DNI data is made with carefully selected lower and upper bounds and correction factors for the geographical location under consideration. These DNI profiles are then utilized as input to the solar plant simulation model to obtain n electricity production results. The output from the simulation is compared with the reference/actual production of the plant. The process is then repeated a *sufficiently high* number of times to make probability distributions and thereby characterize the uncertainty values for each forecasting hour and days that are analyzed.

Validation of the power plant model was made by comparing the simulated values with real DNI profiles and production data of a commercial solar thermal plant in Spain. Figure 5-4 gives the histogram of 1,000 simulations carried out per forecasting horizon, and the associated probability density functions (PDFs) of the net electric power generated. The forecasting horizons correspond to DAM (FH -13), IDM1 (FH 1), IDM5 (FH 8) and IDM6 (FH 12). With this histogram, any final submitted offer/bid has an associated level of confidence associated with it.

Figure 5-5 gives the net electricity power output for two clear, sunny days and a partly cloudy day.

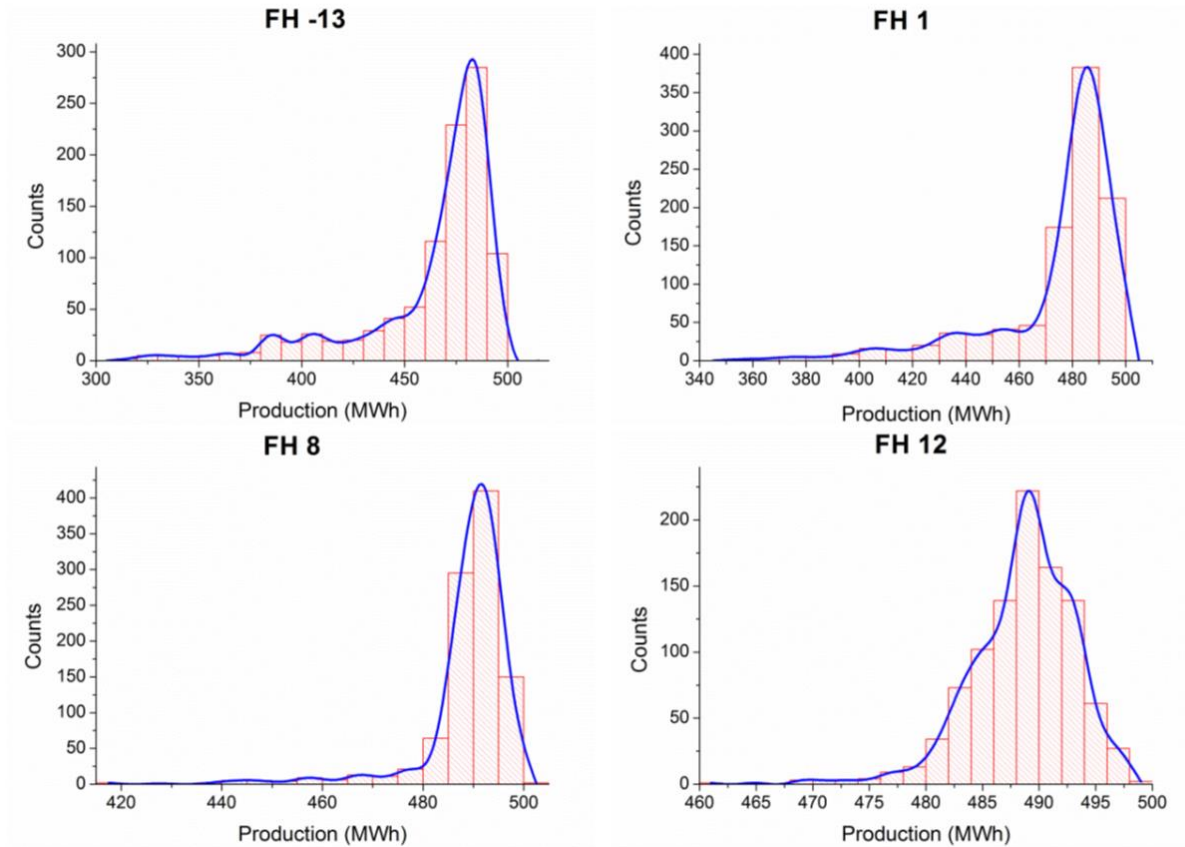


Figure 5-4 Histograms of net daily electricity production and corresponding PDFs for 24th March, 2018, using different forecasting horizons (FH).

With respect to characterizing uncertainty in wind power output, there are two approaches which are hybridized for more accurate realizations, namely physical and statistical approaches [29], [30]. The physical approach focuses on wind flow and the wind plant power curve for estimation of the power output. This method utilizes the wind farm and terrain characteristics, numerical weather prediction, and SCADA data as inputs to obtain the wind turbine power curve and finally the wind generation forecast. This approach has high level accuracy for long term horizons including DAM and also bilateral markets.

The statistical approach, on the other hand, employs historical data and meteorological predictions to estimate new generation output. Meteorological variables such as wind speed, wind direction and temperature are the main inputs in this method while the output is a statistical model (e.g., probability density function) that gives the wind generation forecast. The statistical approach is especially accurate for intra-day energy market updates as well as for short term ancillary service markets horizon. Losses associated to both of these approaches are wake (dependent on wind direction), environmental losses are also factored into the models for more accurate forecasts.

A hybrid of these two approaches can also be made to achieve their accuracy benefits for better wind generation forecasts within specified confidence levels.

With respect to the wind uncertainties considered in this WP, historical data of actual measurements from different wind farms in Spain were prepared and provided by project partner Iberdrola. Such data was then processed in order to obtain the most likely value and its confidence bounds for each time period of each market horizon.

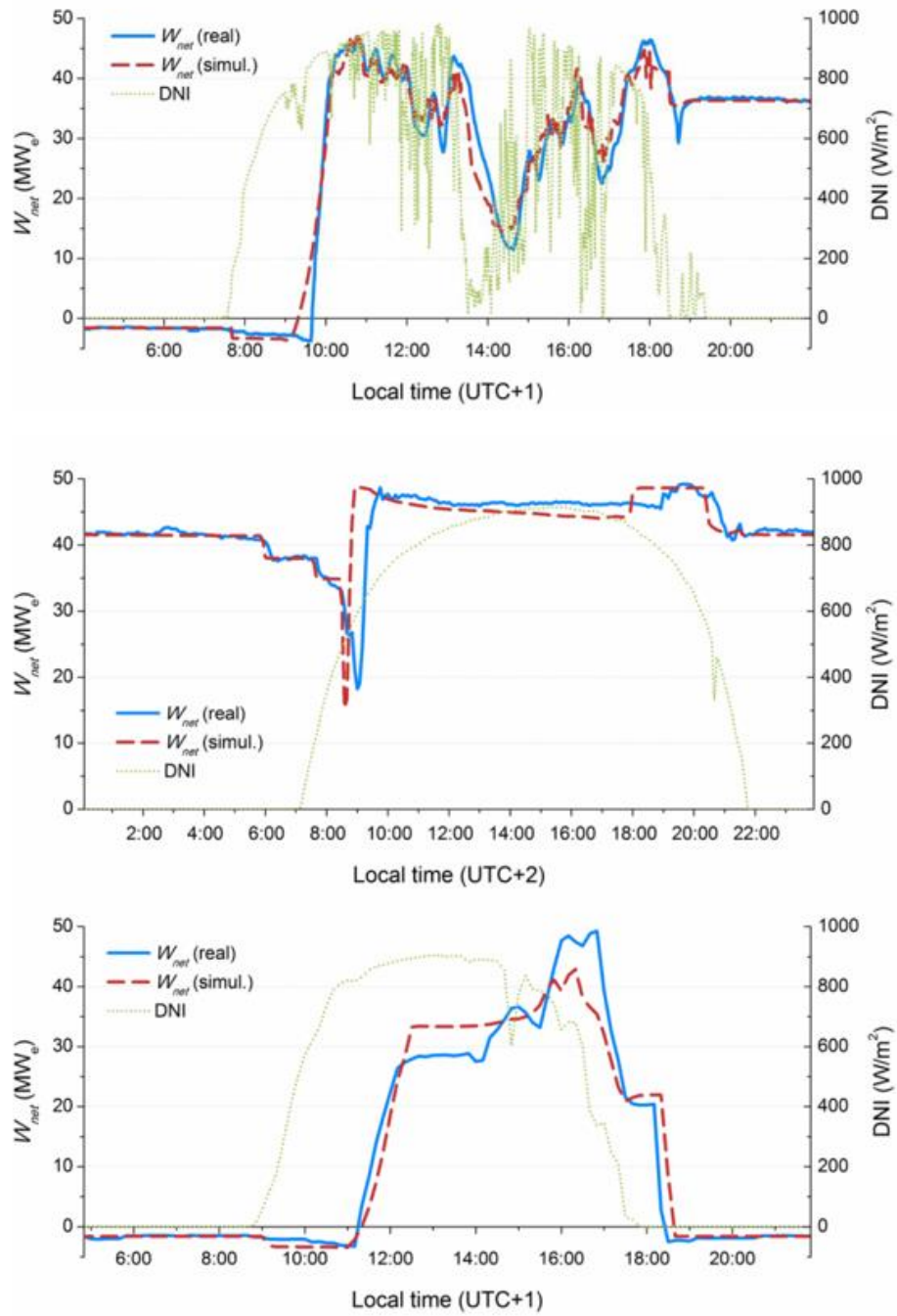


Figure 5-5 Net electric power generated by a commercial STU plant and obtained from the simulation model, including measured DNI, for three representative days: (a) 24th March 2018, (b) 8th July 2018 and (c) 9th December 2018.

5.5 Demand

Another source of uncertainty in DVPP operation is demand. Appropriate characterization of the associated demand uncertainty is especially required with the generation components of the DVPP which are subject to inherent uncertainties themselves. Several demand management frameworks have been introduced to cater for demand uncertainty [31], [32]. However, many of these studies in one way or the other affect consumer's comfortability. In this WP, we propose another way to consider demand inclusion in DVPP participating in energy and/or power markets. This method involves bi-level flexibility associated with the different energy markets, DAM and IDM to take care of inherent demand uncertainty (see Section 4.6).

We consider particularly large (industrial, airport) or aggregated loads (residential) with enough volume to provide flexibility for the stochastic generation sources in the DVPP. The choices of these loads are made weighing their inclusion in an actual future DVPP. Each of these loads has a default profile that represent their normal activities. For example, normal load profile of an industry might be a daily morning to evening shift (8am-6pm) with a fairly constant consumption of x MWh. At other periods (7pm-7am), hourly consumption might stand at y MWh per hour with $y < x$. In our framework, the DVPP manager invites the industrial demand to present other profiles that mirror other operation activities. E.g., splitting the 10 hours constant profile into 5 hours (8am-12pm) *peak* and 5 hours (1pm-6pm) *valley* and vice versa. For the different profiles, the total daily consumption is expected to be kept equal.

The same idea can be extended to other demand types such as an airport and aggregated residential demands. In these two cases however, dramatic alterations of the default activities are not expected. For instance, in an airport, flights generally take off in the early and late hours. Thus, it is expected that load profile shifts e.g., peak shifting does not very greatly. The same reasoning can be applied to residential demands. Studies have been done to characterize the evolution of consumption activity in airports and also for aggregated demands. The profiles utilized in the illustrative examples presented in Chapter 0 were obtained in [33] for airport load and [34] for residential demands. The selection of an optimal profile based on the forecasted energy market prices is the first stage of solving uncertainty.

Finally, for the second level, it is expected that each demand, at the point of presenting the profiles, gives a tolerance value over its nominal consumption. This, on one hand, helps to cater for demand operational nuances. On the other hand, it also could be a source of flexibility for the generation units in the DVPP if they fall short of their scheduled production offers.

6 Illustrative Examples and Preliminary Results

6.1 DVPP Participation in Energy Markets

In this Section, a set of illustrative examples are discussed which serve to test and validate the RES-based DVPP model presented in this document [23]. The study considers the network-constrained unit commitment model of the DVPP to submit DAM auctions and consequently participates in IDM to correct for deviations. Finally, the DVPP operation on different weather conditions of uncertainty is assessed.

6.1.1 Description of the Case Study

The DVPP are distributed across a 12-node network connected to a main grid through a Point of Common Coupling (PCC) as shown in Figure 6-1. The network is a representation of a typical area in Southern-Europe, that was proposed in Deliverable D1.1.

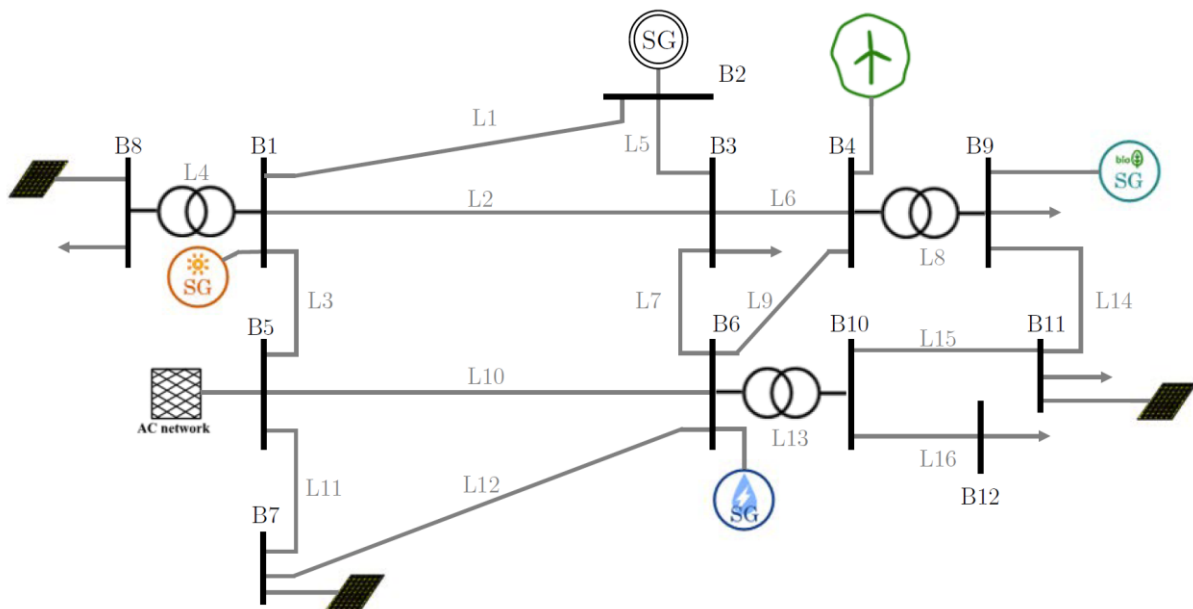


Figure 6-1 Scheme of the Southern-Europe 12-node network

The capacities of D-RES, namely hydro (bus 6) and biomass (bus 9), are 111 and 5 MW respectively. The ND-RESs (wind-farm at bus 4 and a solar PV at bus 8), and the STU (bus 1) power block have rated capacities of 50 MW each. The thermal storage capacity of the STU is 1100 MWh (thermal). Note that thermal storage can only be charged from the solar field and not from the main grid. The demands considered are industrial, airport and residential loads (buses 3, 9 and 12, respectively) with minimum daily consumption of 800, 580, and 600 MWh respectively. Three profiles are associated with each demand and total consumption for each profile is the same.

6.1.2 Input Parameters

The DVPP participates in DAM and then in IDM of the Spanish market, described in Section 2.2.2, to adjust its offers based on ND-RES updates, unplanned shutdowns and/or network contingencies.

A time horizon of 24 hours with an hourly timescale is utilized during DAM, while a subset of the 24 hours is used for each IDM session (see Figure 2-3). The DVPP has the possibility to supply its internal demand, partially or entirely, by buying energy from the main grid at the PCC if needed. In our case, the maximum value of energy that the DVPP can buy is 110 MWh.

Furthermore, we make computations for different seasons and days based on historical data of actual and forecast profiles. Figure 6-2 shows estimated wind power output and irradiation levels in Southern Spain for a clear, sunny day in March 2014 and a day with cloud covers in March 2018.

For demands, we show the three loads in Figure 6-3, namely industrial, airport, and residential, with three different available profiles provided by the demand owner as follows: basecase, early peak, and late peak.

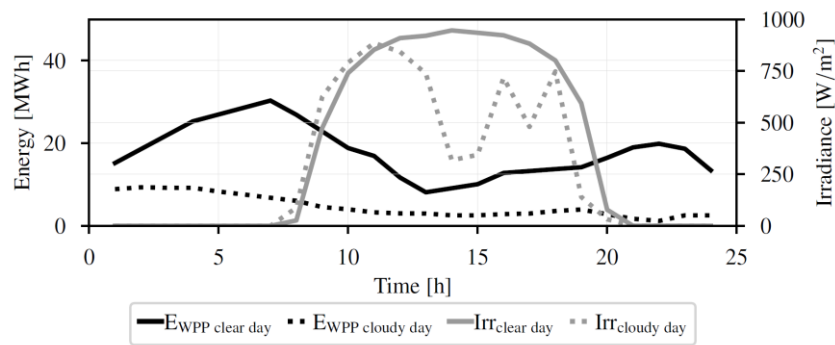


Figure 6-2 Forecasts for STU, WPP and PV generation on a clear day and a cloudy day.

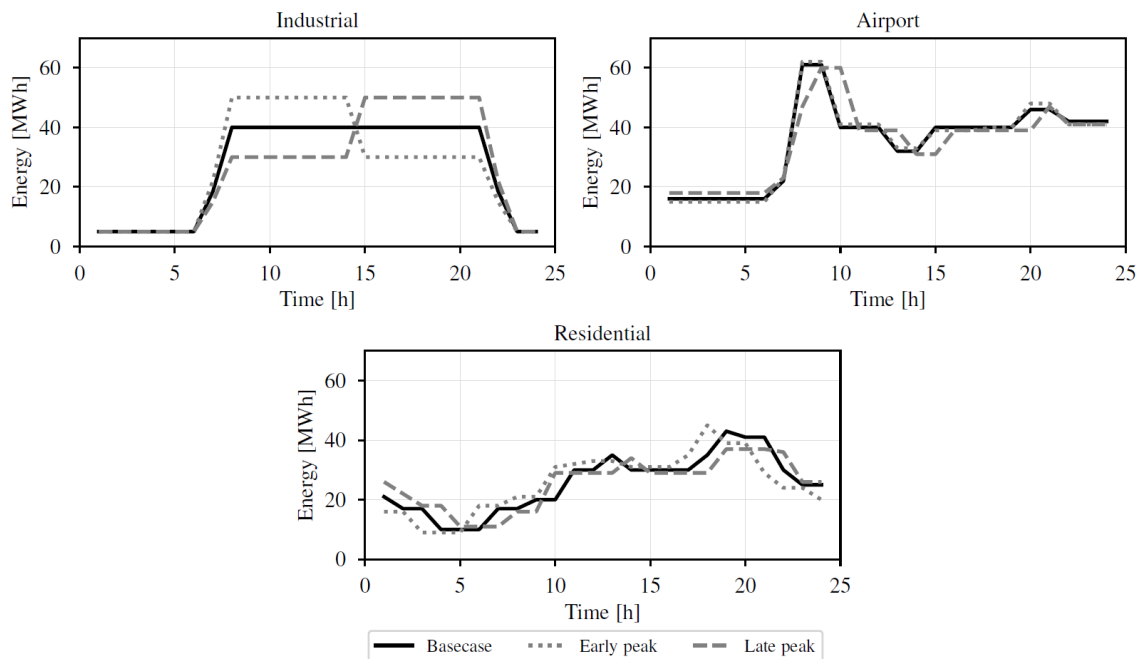


Figure 6-3 Industrial, airport and residential demand profiles.

While fictitious, the base profile replicates *default activities* of airport and residential electricity consumers while other profiles are designed to perform peak shifting around it. During IDM, the demand owner allows a 10% tolerance for demand movement over the selected profile at DAM. In Figure 6-4, representative prices for DAM and all IDM sessions for both clear and cloudy days are presented.

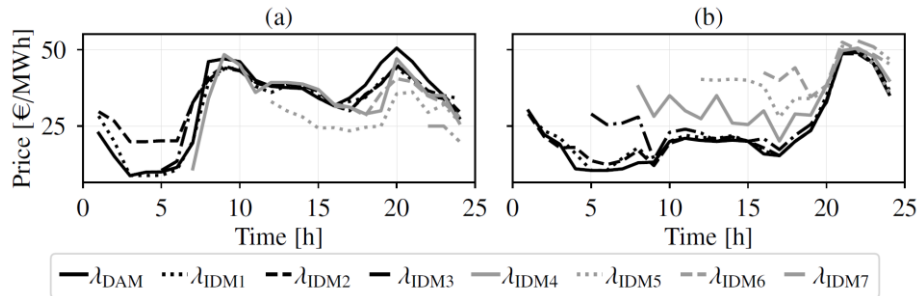


Figure 6-4 DAM and IDM prices on a (a) clear day, (b) cloudy day

6.1.3 Results

To test the effectiveness of our model, we identify two operation strategies:

- Base case where generation or consumption units act individually (No Coordination).
- Coordinated DVPP operation as proposed in this document.

First, we outline the benefits of the DVPP strategic behaviour over the No Coordination case for the DAM and the first IDM session with a default load profile in both cases.

Profit comparison between the days and the strategies is shown in Figure 6-5. For the clear day, there is a 5% and a 28% increase in the profits during DAM and IDM, respectively, when the DVPP model is compared to the case without coordination. However, these profits are more significant during the cloudy day where the DVPP outperforms the base case with 20% and 99% during DAM and IDM, respectively.

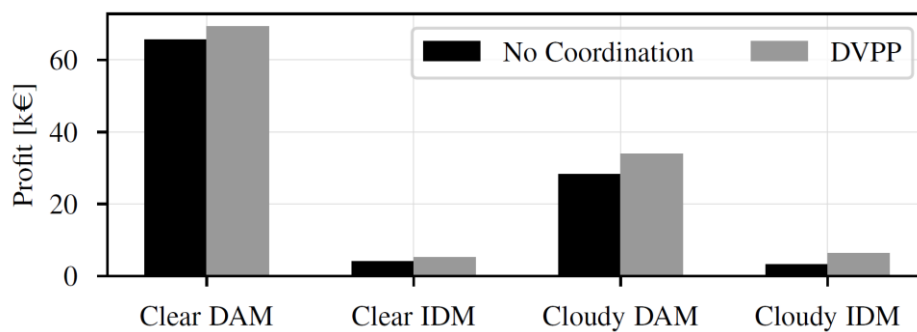


Figure 6-5 DVPP benefits with different market participation strategies.

To fully comprehend the effectiveness of the proposed DVPP model, we analyse the following scenarios in detail: firstly, a clear day with high wind power plant output, high irradiance level, and secondly, a day with intermittent cloud covers in the afternoon and low wind power output. Each of these two broad categorisations will be further examined under (a) Base case with default load profile (b) DVPP with default load profile and (c) DVPP with three load profiles at zero cost. Finally, we conduct an analysis to ascertain the behaviour of non-zero cost demand profiles on a clear day.

6.1.3.1 Traded Power and Output of DVPP Assets on a Clear Day

Figure 6-6 shows traded power on a clear day during DAM and all IDM sessions and Figure 6-7 depicts the expected behaviour of the different assets at DAM. The effect of coordination is evident from the smoothing of the traded power curve from period 10h-16h of the DVPP compared with the base case. The differences arise largely due to proper synchronization of the STU with its storage and the biomass plant response to the market price. The low volume of energy traded in period 8h-9h coincide with very high demand and relatively low generation in the three cases.

Moreover, in terms of benefits to the DVPP, case (c) with three load profiles at zero cost has the highest profit because it leverages differences in the load shape and chooses the best profile to suit its objective. The residential late peak profile was selected in this instance while the early peak profiles were chosen for both the industrial and airport demand.

For IDM participation, after updates to prices and output forecasts of ND-RES, the DVPP manager (or owner of each asset in case of No Coordination) makes adjustments to DAM auctions and in most cases, prioritizes the ND-RES over the D-RES units. Additionally, most updates are made in the earlier IDM sessions as evidenced in Figure 6-6 where there are no changes in offers made in IDM5 through IDM7.

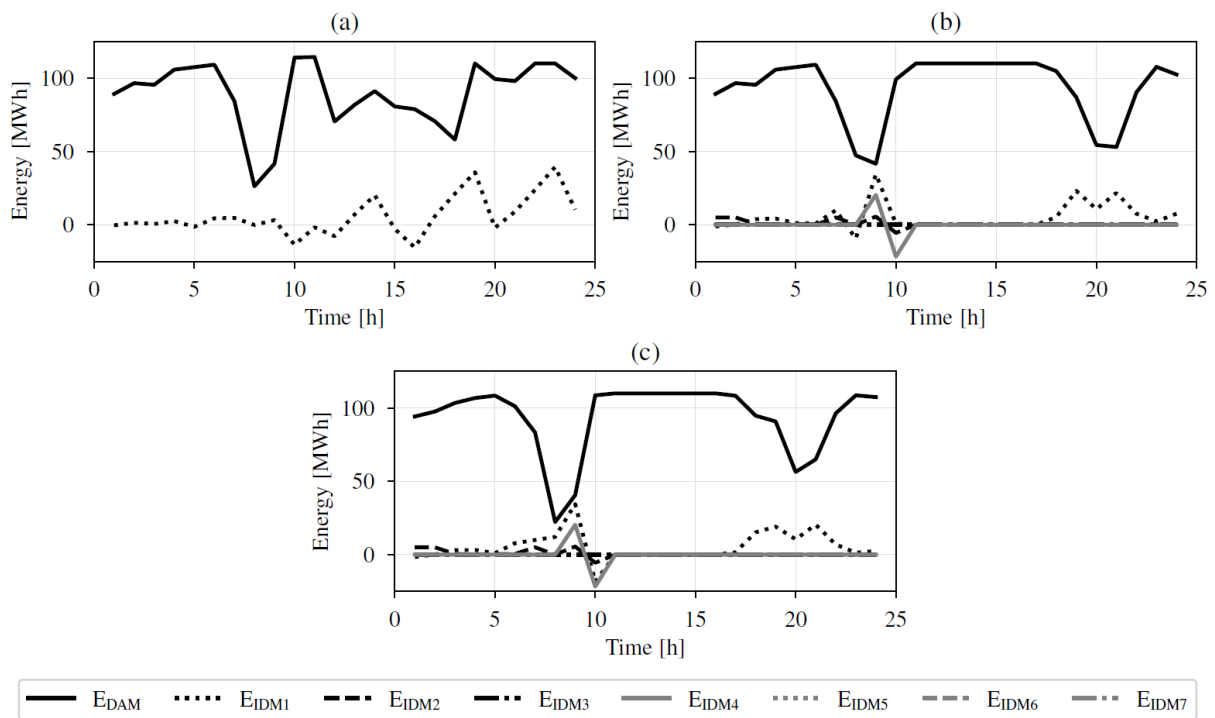


Figure 6-6 Traded power on a clear day at DAM and IDM for three cases: (a) No Coordination, (b) DVPP with default load profile, (c) DVPP with three load profiles.

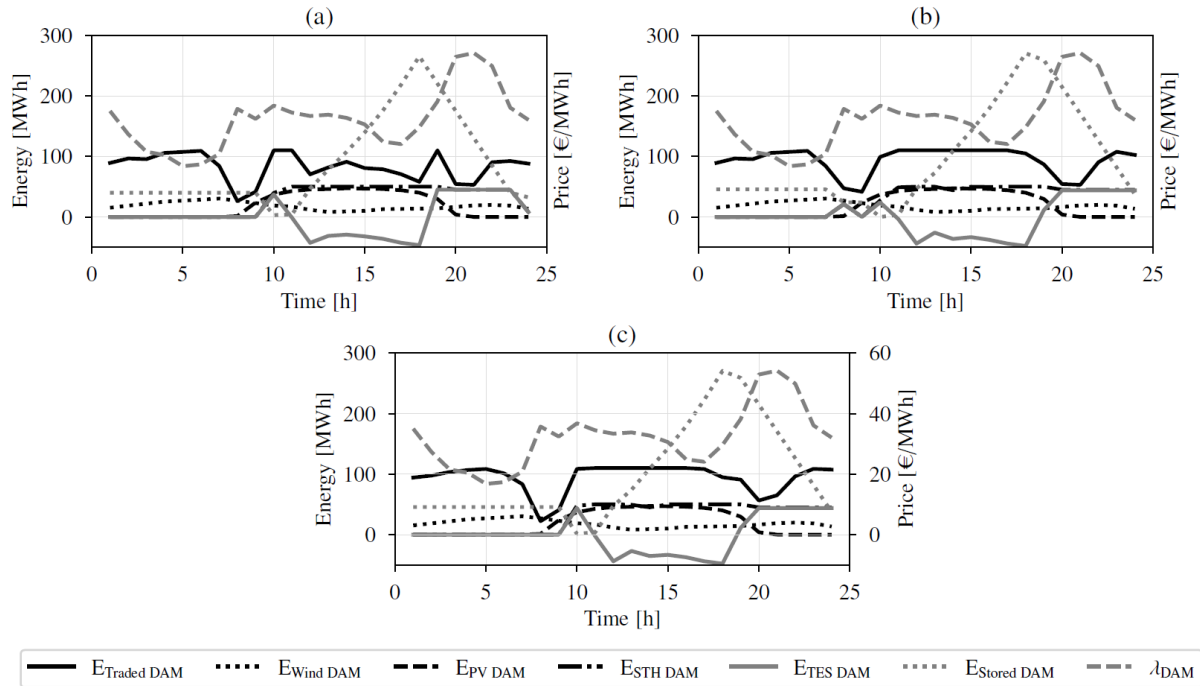


Figure 6-7 Output of assets at DAM on a clear day for three cases: (a) No Coordination, (b) DVPP with default load profile, (c) DVPP with three load profiles.

6.1.3.2 Traded Power and Output of DVPP Assets on a Cloudy Day

The DVPP behaves differently on a day with intermittent cloud covers in the afternoon. There are more activities during IDM as the forecasts of ND-RES are in flux as shown in Figure 6-2. These uncertainties, however, are taken care of by the model as observed in Figure 6-8(b) and Figure 6-8(c) where IDM bids reflect their expected behaviour. With respect to demand, the early peak profiles were selected for both industrial and airport demands whereas the base case was retained for the residential demand.

The comparative advantage of the DVPP over base case was the operation of the STU at the early hours. The STU charged the thermal storage instead of delivering energy from solar field to PB at lower efficiency, and thereafter delivered it at high PB efficiency while also capturing the high prices towards the end of the day as shown in Figure 6-9(b) and Figure 6-9(c). This is in contrast to STU model with average efficiency value where there is no incentive for choosing the operation region. Additionally, in terms of benefits to the DVPP, STU model with linear piece-wise formulation of efficiency gave a 1% increase over using an average value.

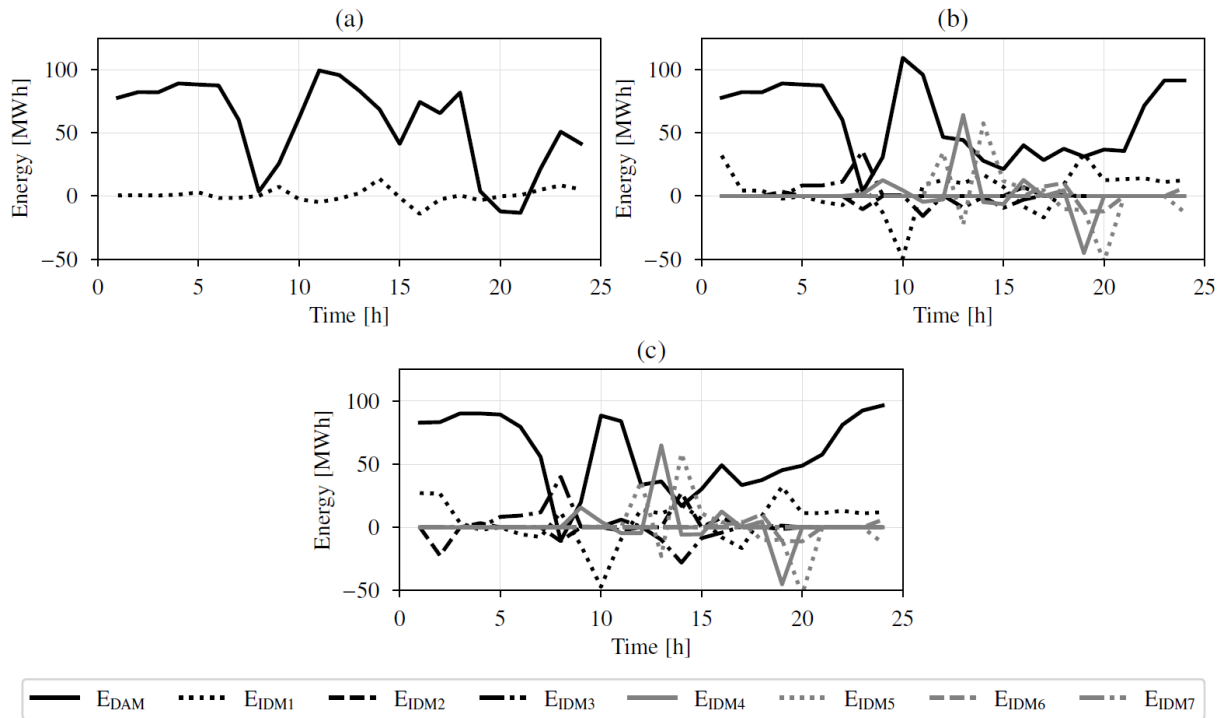


Figure 6-8 Traded power on a cloudy day at DAM and IDM for three cases: (a) No Coordination, (b) DVPP with default load profile, (c) DVPP with three load profiles.

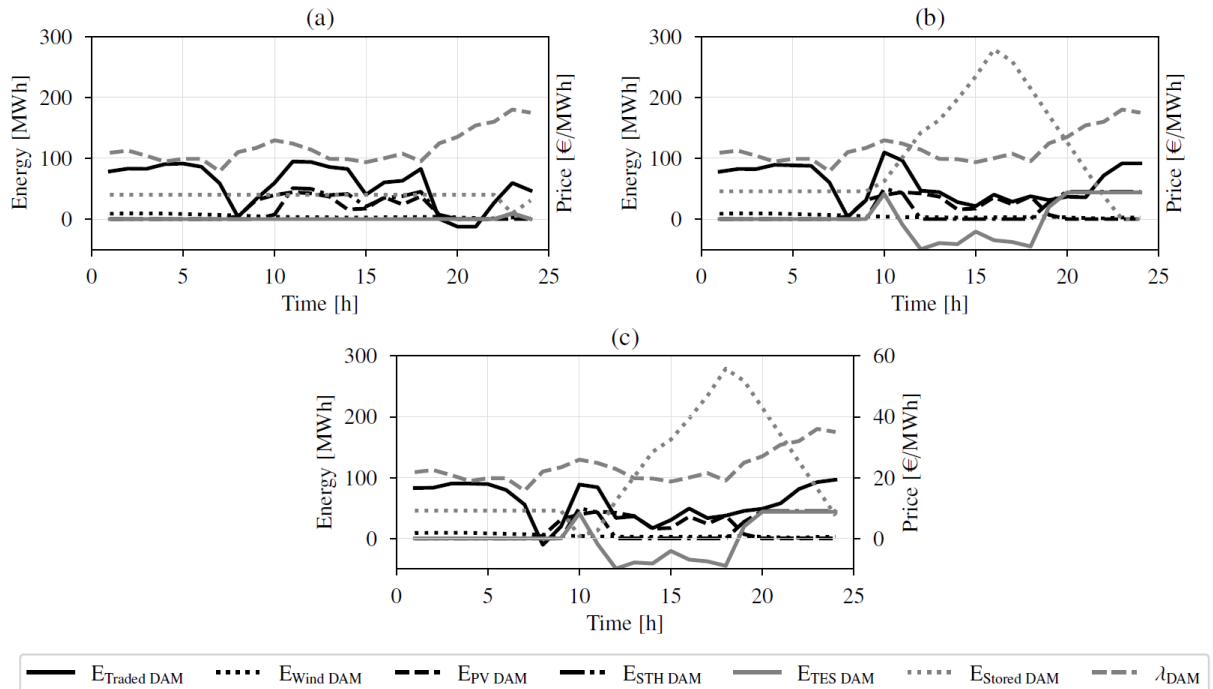


Figure 6-9 Output of assets at DAM on a cloudy day for three cases: (a) No Coordination, (b) DVPP with default load profile, (c) DVPP with three load profiles.

6.2 A Deeper Look into Demand Response in a DVPP

Section 6.1 above serves to illustrate the behaviour of the overall DVPP and its assets participating in DAM and IDM energy markets. This section complements the results discussed previously, and presents preliminary results that serve to test and validate the bi-level demand flexibility model in a DVPP participating in energy markets, that was formulated in Section 4.6 [20]. The same 12-node Southern-Europe network described in Section 6.1.1 is considered for the case study, and the energy market structure followed is the Spanish one.

Figure 6-3 above shows the three profiles considered for each of the loads. The basecase profile simulates *default activities* of electricity consumer, i.e., the consumption profile that would be followed by the demand if no market participation is considered. The other two profiles (early and late peaks) are designed to perform load shifting around the basecase. Other profiles can also be easily added to capture other modes of demand interaction with the market. During IDM, the demand owner allows a percentage of tolerance for demand movement over the selected profile at DAM. In this case study, symmetric tolerances from 10 to 50% over the total demand are considered. Note that the highest tolerance values considered serve only as an illustrative study, as likely no demand owner would allow such variations in a short notice (sometimes as short as 1 hour).

6.2.1 Results

To test the effectiveness of the proposed model, the two operation days considered in Section 6.1.2 are considered, namely a clear sunny day and a day with intermittent cloud covers.

Two aspects are thoroughly discussed for each day, as follows: (i) optimal price to be offered by the DVPP to the demand owners and (ii) effect of the flexibility provided by demand on the profits accrued and operation of the DVPP.

6.2.1.1 Optimal Price Offered by DVPP to Demand Owners

First, we provide a solution to the benefits for demand owners and show that there is a maximum daily total ($C_{d,p}$) and a price per MWh that the DVPP is prepared to pay demand owners such that it is still profitable. The default load profile has zero cost because the demand owner follows it regardless of other events. The DVPP manager then decides what price to pay demand owners for other profiles such that its benefits are not eroded.

Clear Day:

The optimal choices of demand profiles obtained for DVPP operation on a clear day is shown in Table 6-1 profile choice clear day}. These are obtained when $C_{d,p}$ for every other profile is set to zero. Industrial and residential loads have the early peak and late peak as optimal profiles respectively.

Table 6-1 Demand profile choice at non-zero costs on a clear day.

Demand	Basecase	Early Peak	Late peak
Industrial	Chosen when cost > €320/day	Optimal	✗
Residential	Chosen when cost > €180/day	✗	Optimal
Airport	Chosen when cost > €500/day	Optimal	Suboptimal - Chosen when cost > €305/day

To determine the cut-off costs before the basecase is selected, costs for other demand profiles are then gradually increased (simultaneously for all demands). It was then observed that the DVPP manager is only willing to pay up to €320/day to the industrial load owner. The availability of the default profile ($C_{d,p} = 0$) acts as an economic viability check for the DVPP. The €320 is thus the maximum price offering for the early peak industrial load profile, after which it is no more profitable for DVPP. The industrial late peak profile is not profitable at all and neither is the residential early peak profile.

In the case of the airport load, there are more options for both the airport demand owner and the DVPP manager. The early peak profile is profitable for the DVPP manager as a cost up until €500/day while the late peak profile is only profitable until €305/day.

As observed in Figure 6-3, the different airport profiles have only subtle differences. Additionally, the load profiles have a benefit-inducing relationship with the evolution of the market price on this clear day. Indeed, the first profile peaks (periods 8-10) correspond to lower electricity prices and thus account for the higher costs which the DVPP is prepared to pay.

When the demand cost per MWh of the optimal profiles are computed, proof of the hypothesis is further demonstrated. For the airport profiles, $C_{d,p} = €10.42/\text{MWh}$ for 48 MWh shifted and €7.44/MWh for 41 MWh shifted of the early and late peak profiles respectively. Contrast this with industrial early peak profile where $C_{d,p} = €4.35/\text{MWh}$ for 73.5 MWh shifted. Thus, the €/day offer from DVPP depends a little less on the magnitude of energy shifted and more on the load profile shape with respect to market price.

Finally, these costs per MWh associated with DAM represent lower bounds on the price that DVPP is willing to pay demand owners. With the tolerances allowed in IDM, DVPP benefits increase and the prices paid to demand owners are expected to follow the same trend.

Cloudy Day:

On a cloudy day, it is observed that for all demands, the late peak profile is not optimal for the DVPP operation (see Table 6-2). Additionally, the DVPP manager is unwilling to pay amounts as high as the clear day case. Only €90/day and €260/day is offered to the industrial and airport load respectively. For the residential load, the deviations from the default load are not optimal at all and the DVPP manager thus, offers no price to the residential load owner.

Table 6-2 Demand profile choice at non-zero costs on a cloudy day

Demand	Basecase	Early Peak	Late peak
Industrial	Chosen when cost > €90/day	Optimal	✗
Residential	Optimal	✗	✗
Airport	Chosen when cost > €260/day	Optimal	✗

6.2.1.2 Effects of Demand Flexibility on DVPP Profits

This section first discusses the effects of demand flexibility on profitability of the DVPP. Effects of percentage flexibility allowed by the demand owners are next studied.

On a clear day, the DVPP manager can realize a profit of €68259 from participating in the DAM (first demand flexibility level). However, at the end of the operation horizon (i.e. final IDM session), this profit can increase by up to 14% attributable to the second demand flexibility level alone beyond its DAM objective. The relationship between second-level flexibility allowance

and the associated effect on profits is shown in Figure 6-10. Beyond 40%, profits do not show any considerable additional increase and any allocation on load movement beyond this percentage only leads to more saturation on the profits curve.

Figure 6-11 shows the impact of demand flexibility on total power traded in DAM and total traded after all IDM sessions. It is observed that increasing flexibility provision reduces the valley in DAM offer around the instant $h = 8$ and leads to an increase in offers in the energy market while at the same time flattening the curve in the straight section from periods 9 to 19 but keeping total energy consumption constant.

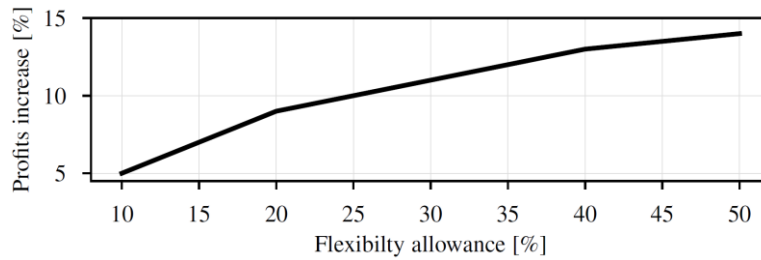


Figure 6-10 Demand profile flexibility on DVPP profits on a clear day.

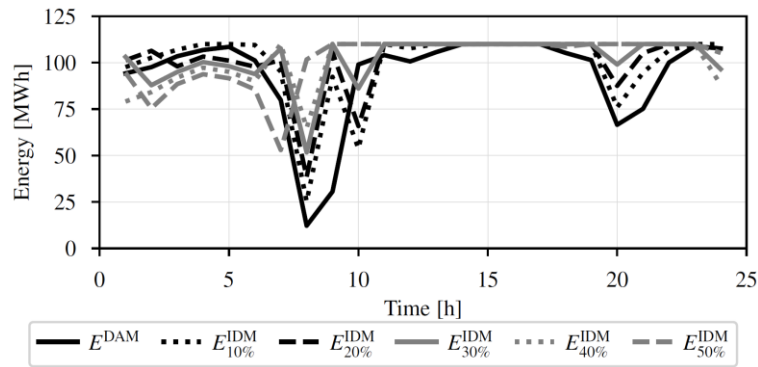


Figure 6-11 Scheduled and final traded power based on demand flexibility.

Final demand output relative to DAM offer is shown in Figure 6-12. Up to 20% flexibility allowance on demands, the variations are smooth and would not necessarily alter normal system operation. However, from 30% and upwards flexibility, higher consumption pattern is observed in demand as evidenced in the industrial and residential demands at periods 10-13 and 17-19. Increasing flexibility allowance gives rise to more of this peaks that might affect system performance. Demand owners would likely not allow such percentages anyway and we simply show a proof of concept here.

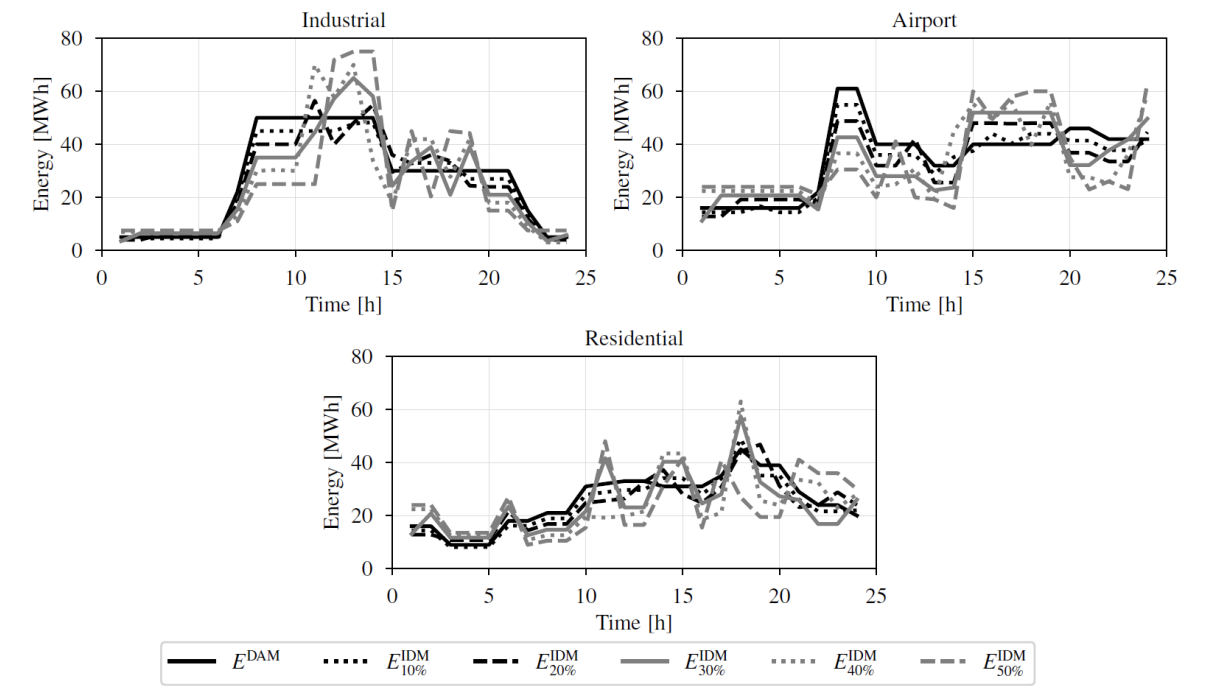


Figure 6-12 Scheduled and final demand outputs on a clear day.

7 Concluding Remarks and Future Work

This deliverable concludes Task 5.1, and proposes the core of a novel RES-based DVPP model that optimizes its operation and configuration when participating in European energy and ancillary service markets.

A review of the different markets that are currently put in place was carried out, and a selection of the most promising ones from the DVPP's benefit perspective has been presented and discussed. It has been concluded that, with their current schemes, DAM, IDM and SRM are particularly good fits for the purposes of this WP.

With this in mind, the DVPP model core considers different business cases of the DVPP by properly selecting the objective function of the optimization model such that the DVPP participates in one or more of the three markets listed above.

A thorough analysis of the different assets that the DVPP may comprise was also presented. These include conventional, dispatchable RESs such as hydroelectric and biomass generation; stochastic, nondispatchable RESs such as wind farms, solar PV plants, and concentrated parabolic trough solar-thermal plants with storage capability; and flexible demands. Detailed models of each of these assets were formulated and discussed. Particularly relevant are the models of the solar-thermal plants with storage capability and the flexible demands, as they have been specifically designed and tailored for the purposes of this WP.

One of the main goals pursued in this WP is to demonstrate that a properly coordinated DVPP can outperform, from the economical and operation points of view, electrochemical BESSs. With this aim, specific constraints of BESSs were also formulated, e.g., degradation and self-discharge processes.

Finally, since any of the systems listed above need to be necessarily connected to an electrical grid to operate, the network constraints have also been modeled, including the nodal power balances, and line active power flow limits.

Simulation results from the illustrative examples presented, and which consider a DVPP in the Spanish system, have served to test and, to some extent, validate the proposed model. Results show that by coordinating several units in the form of a DVPP, they can achieve higher benefits than when participating on the markets as individual offering units, even if such participation is optimal. Results also have shown that flexible demands, can play a crucial role in DVPPs, if market operators allow them to be combined with generating units as a single market participant.

The DVPP model core proposed in this work will be gradually extended in several ways throughout the remainder of this WP, by adding functionalities as the different Tasks are carried out. Some of such extensions are discussed below.

On the one hand, the different uncertainties that characterize the DVPP model and that were thoroughly discussed in Chapter 5, will be addressed in Task 5.2. Such uncertainties will be considered by implementing the so-called *Robust Optimization* (see Appendix B), and will be key to account for the stochastic nature of wind speed, solar irradiation, market prices and demand profiles.

Concurrently, real-time operation of the DVPP will be studied in Task 5.3. This would allow DVPP assets to be rescheduled after their DAM, IDM and/or SRM schedules have been set (see Appendix A). Such rescheduling might be due to, e.g., unplanned shutdowns of any of the

DVPP assets, line outages, aFRR commands from the system operator, etc. The DVPP must be able to reschedule its units as required, in an effective and relatively fast manner, and minimizing the associated costs.

The DVPP model considered in this document behaves as a *price taker*, i.e., its size is sufficiently small compared with the total system capacity, and thus its market power is limited. In other words, the DVPP model takes the different market prices as given inputs. However, if the DVPP is of enough size, or if a large number of DVPPs are participating in the market, then they will be able to affect the market clearance prices, becoming a *price maker*. In such case, where the DVPP is aware of its own market power, the optimization model needs to take into account the fact that the DVPP will naturally tend to alter the price in order to maximize its profits. However, the market clearance price depends also on other participants with market power. The optimization problem thus becomes a multi-level problem, where in the first level the DVPP tries to maximize its profit, whereas in the second level the clearing of the market is solved by assuming that the DVPP knows the offers/bids of the other market participants. The latter is a rather strong assumption, which can be handled by properly modelling such uncertainties. Being a price maker thus increases substantially the complexity of the problem.

Finally, we remark the fact that some markets are expected to see significant changes in the next years with the implementation of, e.g., PICASSO (aFRR), MARI (mFRR) and TERRE (RR), which will require their modeling and analysis.

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A Real Time Operation

Focus of this document is mainly on the description and model formulation of a DVPP participating in different and sequentially distributed electricity markets to fulfil a specific objective. This market participation assumes that, once the last market of each delivery period is cleared, the DVPP will be able to generate/consume the energy/power that was scheduled at each period. However, this is never guaranteed, as various events can lead to mismatches between scheduled and finally traded energy/power. Such events can be directly related to the DVPP (e.g., unplanned shutdown of one of its plants due to technical malfunction), or external to the DVPP (e.g. the loss of a line which might require redispatch of assets to avoid line congestions/overload, or changes in the secondary reserve set points from the TSO).

Therefore, the main objective of real time operation for a DVPP typically consists in the effective coordination of its assets to supply or consume its scheduled energy/power in *real time*¹⁰ with as little deviations as possible, while considering the events discussed above. The real time operation is thus opposed to DAM and IDM activities, which both require prior submission of energy bids/offers to be traded at a later time. At real time, the system operator instructs DAM and IDM participants to deliver their proposed offers with their scheduled regulations, if applicable, so as to ensure overall system balance. Figure A-1 shows an emulation of plant behaviour during real time. As opposed to the single bid in an hour at DAM/IDM, there are expected variations during actual operation period based on network events, contingencies and TSO commands for setpoint changes.

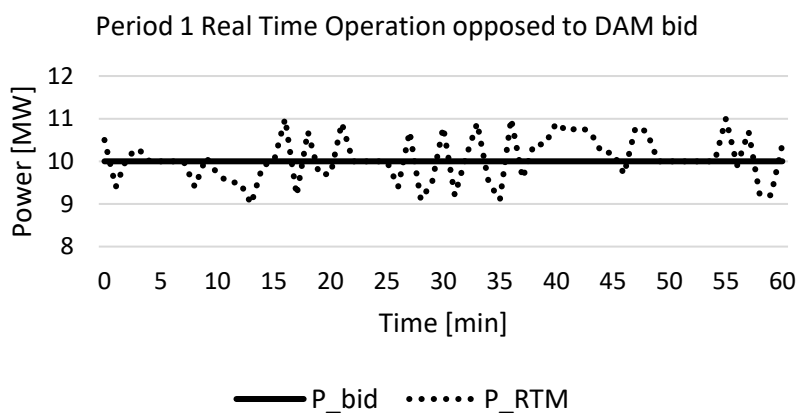


Figure A-1 Illustration of plant behavior during real-time operation.

Due to the aforementioned reasons, the nature of objective function to minimize deviations from submitted offers needs to be considered carefully. The objective also needs to be paired with appropriate constraints so as to ensure balance among the DVPP generating units, its demand assets, line flows, and technical operation constraints of all units. All of these need to be solved in a very short time because the TSO sends out set points to generators every 4 secs in the case of, e.g., the Spanish system, and assets need to be redispatched (if required) in less than that timeframe for timely and proper power delivery.

¹⁰ Note that, in the context of this Section, *real time* refers to time frames between a few seconds and several minutes before power delivery. Not to be confused with the *real time* considered in dynamic performance, control and stability studies, which usually rely on instantaneous actions based on online measurements of system quantities.

Considering that real time operation does not seek to directly offer any economic benefits but basically exists to ensure system balance, the pertinent questions to answer in the formulation of the real time operation are:

- i. How to effectively assign up/down regulation requirements to each DVPP unit?
- ii. How to ensure individual units provide power at their scheduled level?
- iii. How to avoid simultaneous provision of up and down regulation at the same period?

To provide an answer to some of these problems, we choose an objective that incorporates three components.

- a) The operation cost of units used during the DAM offers/bids, this ensures that there is no total reschedule based on regulation costs
- b) The regulation costs of the DVPP units which serve as weights to ensure that the preferred units are used first for regulation. These weights could be based on speed of response of the unit, proximity to a congested line or other factors. An example of this is shown in Fig 2.
- c) A cost function that ensures non-simultaneous provision of up and down regulation by individual DVPP units at the same instance of time.

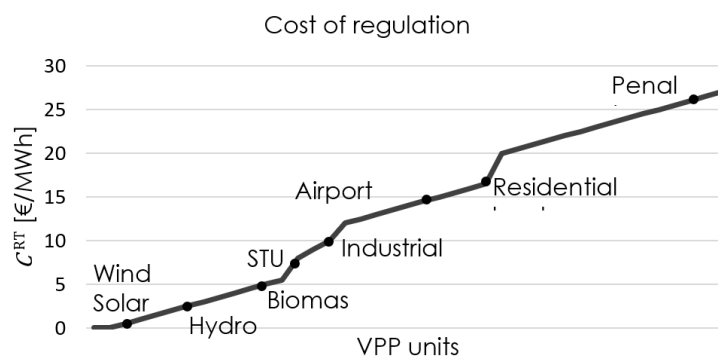


Figure 8-1 Opportunity costs used for regulation provision during real time operation.

The Real Time Operation Problem introduced in this Appendix will be duly addressed in following Tasks of this Work Package, where detailed formulation, implementation and evaluation will be presented and thoroughly discussed.

B Robust Optimization vs. Stochastic Programming

Two main approaches can be followed to model systems under uncertainty in optimization problems, namely *Robust Optimization* and *Stochastic Programming* [35]. Both approaches deal with the issue of certain model parameters taking random values that usually affect decision-making, that is, the optimal value of the decision variables.

Ideally, the optimal value of the variables is the one that allows the system to reach the optimum of the objective function, knowing the values of the parameters that they actually took. This *wait-and-see* strategy establishes what would have been the best decision to make if the future was accurately known and see how far the real decision-making and its impact on the objective function are with respect to the forecasted value.

Robust optimization (see its generic formulation in (8.1)-(8.4)) establishes a formulation that allows obtaining the values of the decision variables in the face of adverse realizations of the parameters that the formulation incorporates. It is considered that each random parameter $a_{(i,j)}$, belonging to the set of random coefficients of matrix $\mathbf{A}$ can take a value within the interval $[a_{(i,j)} - a'_{(i,j)}, a_{(i,j)} + a'_{(i,j)}]$. The robust programming gives to the random parameter the value that is most demanding for the model in order to obtain values in decision making that are robust against adverse scenarios. The robust formulation affects the objective function and the constraints. In the objective function the robust optimization sets the demanding values of the cost c_2 within the interval $[c_2 - c'_2, c_2 + c'_2]$, and in the constraints, the applied coefficient matrices $\mathbf{A}_2$ are set facing more challenges in their fulfilment using the resulting coefficients of $\mathbf{A}_2 + \mathbf{A}'_2$. The robust formulation can modify the demanding level of the value of random parameters in order to analyse the impact of this randomness in the decision variable values.

$$\min_{x_1, x_2} c_1^T x_1 + (c_2^T + c_2'^T) x_2 \quad (8.1)$$

s. t.

$$\mathbf{A}_1 x_1 = b_1 \quad (8.2)$$

$$\mathbf{B}_1 x_1 + \mathbf{A}_2 x_2 + \mathbf{A}_2' x_2 = b_2 - b_2'^T \quad (8.3)$$

$$0 \leq x_1, x_2 \quad (8.4)$$

Stochastic programming, on the other hand, models decision making by creating one or more stages depending on the type of variables and optimization periods (see its generic formulation in (8.5)-(8.8)). Thus, for example, if two stages are considered, the variables x_1 belong to the first stage and the variables x_2^ω belong to the scenario ω of the second stage. As shown in the generic linear formulation, the objective function (8.5) minimizes the costs or penalties of both stages. On the one hand, the first part of the objective function is the multiplication of the costs of the first stage and the second part includes the sum of the costs of the second stage of each scenario considered weighted by its probability. As formulated, the first-stage variables x_1 take a single value compared to the different values that the variable x_2 takes in the different ω scenarios. From the point of view of the parameters, there are first-stage parameters with constant values, b_1 , and second-stage parameters that take different values depending on the scenario b_2^ω . The stochastic formulation of the problem requires a preselection of second and successive stage scenarios (if necessary). This preselection determines the values of the parameters b_2^ω in order to better represent the uncertainty faced by decision-making.

$$\min c_1^T x_1 + \sum_{\omega \in \Omega} p^\omega c_2^{\omega T} x_2^\omega \quad (8.5)$$

s. t.

$$A_1 x_1 = b_1 \quad (8.6)$$

$$B_1^\omega x_1 + A_2^\omega x_2^\omega = b_2^\omega \quad (8.7)$$

$$0 \leq x_1, x_2 \quad (8.8)$$

Comparatively evaluating robust optimization vs. stochastic programming, there are advantages and disadvantages in both.

Stochastic optimization has the advantage of greater realism in the evaluated scenarios. This realism means that it makes it possible to concretely evaluate actual second-stage and successive scenarios in the face of first-stage decision-making. On the other hand, depending on the set of scenarios chosen for the second and successive stages, this optimization method allows to establish a clear orientation on the objectives to be evaluated (for example, focused on efficiency, safety, pollution, ...). It also allows the application of techniques decomposition and parallel computation for greater computational efficiency in large problems.

With respect to the disadvantages of stochastic optimization, it can be remarked that the construction of *a priori* scenarios implies a previous step to the optimization that is not always simple or even accurate enough. The selection of the scenarios is key for the results obtained and their stratification in probability and their preparation is a weakness, and in some cases a limitation, of this methodology. Another disadvantage of this methodology is that it is more difficult to carry out sensitivity analysis of decision making with respect to the different options for creating probabilistic scenarios. Finally, its mathematical formulation implies a proportional growth of restrictions and variables with respect to the number of scenarios. This last aspect can be relevant in large problems.

Robust programming method on the other hand is quite flexible in order to perform sensitivity analysis against the robustness levels required in the study. In addition, it has the advantage that the mathematical formulation does not grow in number of variables and constraints as much as it happens with stochastic optimization. Computationally, robust optimization does not change neither the nature nor practically the size of the problem formulation, so it can be applied to large problems without increasing its computational cost.

Robust optimization shows also some disadvantages. First, the flexibility of the robustness applied to the levels of the random parameters does not allow us to know, *a priori*, the specific value that they are going to take in the optimization. This disadvantage means that it is somewhat more laborious to determine the specific scenarios that the optimization problem has evaluated as demanding once a robustness level has been predefined by the user.

Comparing both methodologies, the use of robust optimization is chosen in this project since it allows the user to perform sensitivity analysis on the results with greater ease. Besides, it can be assumed a research challenge to directly obtain the specific realizations of the random parameters after robust optimization.