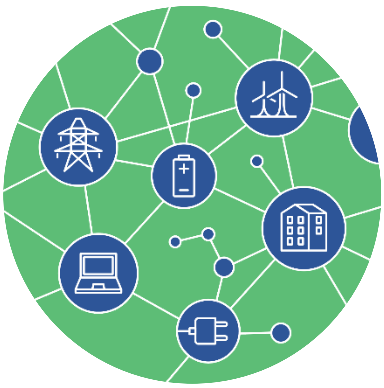
OSMOSE

OPTIMAL SYSTEM-MIX OF FLEXIBILITY SOLUTIONS FOR EUROPEAN ELECTRICITY

Recommendations for market designs and regulations

D2.5



Contact: www.osmose-h2020.eu

The project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 773406

Document properties

Project Information

Programme	**O**ptimal **S**ystem-**M**ix **O**f Flexibility **S**olutions For **E**uropean Electricity
Project acronym	OSMOSE
Grant agreement number	773406
Number of the Deliverable	2.5
WP/Task related	WP2 / Task 2.5 and 2.6

Document information

Document Name	Recommendations for market designs and regulations
Date of delivery	31/03/2022
Status and Version	V1
Number of pages	20

Responsible

Document Responsible	Dario Siface (RSE)
Author(s)	Dario Siface (RSE), Olivier Rebenaque (UPD), Christoph Weber (UDE)
Reviewer(s)	Jens Weibezahn (TUB), Leonardo Petrocchi (TERNA)
Approver	Nathalie Grisey (RTE)

Dissemination Level

Type (distribution level)	☒ PU, Public ☐ CO – full consortium, Confidential, only for members of the consortium (including the Commission Services) ☐ CO – some partners, Confidential, only for some partners (list of partners to be defined)

Review History

Version	Date	Reviewer	Comment
V0	31/03/2022		

Table of content

List of figures

0 Executive summary

The objective of the Work Package 2 (WP2) is to simulate the short-term operation of future European power systems, under different market designs and considering novel flexibility options and space-time downscaling. Within this framework, Deliverable 2.3 described the methodological frameworks developed by WP2 partners in their respective studies. Subsequently, Deliverable 2.4 (D2.4) presented the different case-study set-ups, along with the detailed results of all the performed simulations. In this document, the results of D2.4 are analysed to draw some conclusions in terms of suggestions, remarks and recommendations.

The simulations show clearly that forecast errors on non-programmable renewable energy sources (NP-RES) generation have a significant impact on all market parties, but with different effects. Flexible units may benefit from those forecast errors, since they represent the main source of “balancing” in the IDM.

Power system investment planning should not focus only on the national electricity mix, but should be based on a deep coordination among neighboring countries, since it can significantly impact the CO2 emissions of a given country. The contribution of new interconnectors on addressing forecast errors could be included in their cost-benefit analysis.

Uncertainty should be taken into account also for what concerns the definition of cross-border capacity for DA market clearing. This is important in particular if the flow-based configuration is applied, when the PTDF coefficients should be properly determined. In general, TSO-TSO coordination on cross border capacity should be strengthened, in particular for capacity calculation and allocation, but also for congestion management to make sure transmission lines are used in the most efficient way.

If the investment decisions on storage systems – on batteries in particular – are based only on the economic profitability in the wholesale markets, we may reduce their fundamental contribution to release congestion, thus possibly even opposing to the penetration of RES generation. Then, other kinds of remuneration mechanisms for batteries and storage should be taken into account to favor the support they can provide to the energy transition by improving congestion management.

The availability of the flexibility provided by resources connected at the distribution level may be strongly impacted by the constraints of the distribution network. I.e., the position of distributed resources along the distribution network can be crucial since, on the one side, it might favor or contrast the formation of network congestions, which, on the other side, may reduce the flexibility provided to the System. In particular, if the distributed resources are concentrated in a few portions of the distribution network, the available flexibility can be strongly reduced compared with its potential. This adds another level of complexity for assessing the impact of forecast errors, but is of crucial importance, since the amount of flexibility resources connected to distribution (flexible demand, storage devices, etc.) is expected to grow more and more in the future.

The methodology used for the TSO-DSO interface modelling allows the representation of grid constraints with open data through synthetic networks, thus overtaking data sharing issues in the assessment of the value of distributed flexibility for the system.

1 List of acronyms and abbreviations

In the following table are listed the acronyms and abbreviations used in this document.

Acronym	Meaning
CA	Consortium Agreement
D	Deliverable
DA	Day-ahead
DAM	Day-ahead market
DSO	Distribution System Operator
EU-ETS	European Union Emission Trading System
ID	Intraday
IDM	Intraday Market
NP-RES	Non-programmable renewable energy sources
PHS	Pumping Hydro Storage
RES	Renewable Energy Sources
RoR	Run of River
TSO	Transmission System Operator
WP	Work Package

2 Introduction

The objective of the Work Package 2 (WP2) is to simulate the short-term operation of future European power systems, under different market designs and considering novel flexibility options and space-time downscaling. Within this framework, Deliverable 2.3 described the methodological frameworks developed by WP2 partners in their respective studies. Subsequently, Deliverable 2.4 (D2.4) presented the different case-study set-ups, along with the detailed results of all the performed simulations. In this document, the results of D2.4 are analysed to draw some conclusions in terms of suggestions, remarks and recommendations.

In D2.4, two Europe-wide System approaches have been considered, both applied to a zonal and a nodal market configuration of the European system. The first one is characterized by a “market agent” approach over a single-day time horizon with hourly detail: in the following of this document, the results obtained with this approach will be referred to as “single-day simulation”. The second one, has an “operational system optimization” approach and a yearly time horizon with hourly detail, thus, the results obtained with this approach will be referred to as “one-year simulation”. In addition, within the framework of the single-day simulations with a nodal market configuration, also a methodology for modelling the TSO/DSO interfaces was applied to the power system of central France; in the following of this document, this work will be referred to as “DN simulations”.

This document is organized in sections, each dealing with one relevant topic highlighted by the results of the simulations performed in WP2. Every section is divided into subsections assessing different aspects of each relevant topic and is concluded with a specific subsection for the recommendations. In detail: Section 3 deals with the impact of forecast errors on the behaviour of market participants. Section 4 deals with the importance of cross-border interconnections to tackle the impact of the forecast error on national power systems. Section 5 deals with the effects of a nodal market configuration. Section 6 deals with the issues related to the connection of flexibility resources to the distribution level. Section 7, finally, adds some final remarks to open for future developments of this research activity.

3 Forecast Error Impact on Market Participants' Behaviour

The single day simulations clearly show that forecast errors on non-programmable renewable energy sources (NP-RES) generation have a significant impact on all market parties, but with different effects. For NP-RES generation, being directly affected by forecast errors, they induce additional costs for compensating the error between DAM and IDM. Though the forecast error can be assumed to be symmetrical, the penalty cost will very likely not be, decreasing the investment profitability while at the same time increasing the investment risk. On the other hand, the flexible units may benefit from forecast errors, since they represent the main source of "balancing" in the IDM. These results have several implications that need to be explored.

One first, further analysis should be made in order to assess the impact of an increased share of NP-RES generation on the price volatility (between zones, between timesteps, and between market horizons), considering multiple scenarios with different configurations of flexibility solutions. The study already performed at the European level allows some preliminary conclusions to be drawn in this regard, because the share of renewables in the electricity mix is heterogenous between countries. However, further insights are necessary to assess how the volatility trend evolves with the increase of NP-RES penetration in the electricity mix[1]. In this regard, the assumptions on CO_2 emission prices is crucial for countries with a high share of conventional power plants as flexibility sources.

Then, additional studies should be performed to assess how the potentially substantial imbalance costs for NP-RES generators might affect the investment decisions. In case volatility risk is perceived as a problem, market parties may compensate volatility risk by diversifying their portfolio. Acemoglu et al. (2017), for instance, make such a case, yet they investigate a setting with strategic behaviour in an oligopoly.

Third, if predictable price gaps arise between the DA and ID markets, this might favour arbitrage behaviours. For instance, a market party can take a long position and sell the energy bought in the subsequent market if they anticipate higher prices. Arbitrage in competitive markets should hence lead to a convergence of the DA prices to the (ex-ante) expected value of the later ID markets. In the literature on the interplay between the intraday and the balancing markets, some evidence about strategic behaviour has been reported (Eicke et al., 2021, Just, Weber 2015 and others). Such behaviour is at first sight unlikely in the arbitrage between DA and ID markets, given that in the ID markets there is nothing like the pre-fixed energy prices common in balancing markets, which induce incentives for gaming between spot and balancing markets. Yet further investigations on gaming opportunities, that could exacerbate price volatility, are advisable with the increase in NP-RES penetration.

[1] For instance, in an earlier paper by Wozabal et al (2015), even a decrease in price variance is found for increasing shares of renewables.

The assessment of the effects of the forecast error on the strategies of the market participants might be performed through agent-based models. The model developed by RTE could be extended but several challenges must be addressed. The price forecasting method might be improved but there is a trade-off between the method accuracy and the computational time (Iago et al., 2021). However, with current forecasting methods, the error in RES forecasts only decreases significantly 3 hours before real-time. Even by increasing the accuracy of the forecasting method, no significant change might be expected. Also, the overall complexity of the model made by RTE does not allow for long-term (i.e. yearly) simulations. There is again a trade-off between the scope of the study and model complexity. These hurdles prevent from comparing results obtained in WP1[2] on large data sets.

[2] WP1 worked on the definition of an optimal mix of flexibilities. Simulations all assumed a benevolent monopoly and most of them assumed a perfect foresight.

4 Cross-border Interconnections

4.1 Interconnectors as a significant source of flexibility

NP-RES generation forecast errors induce significant adjustments in the ID market with respect to the results of the clearing of the DA market, and this is evident in the results of both the single-day simulations and the one-year simulations. For instance, for the single-day simulations this is shown in Figure 1, taken from Section 2.4.1.1 of D2.4.

Figure 1: Difference in dispatch for each technology in each country aggregated for all the 24 hours (above) and with a focus on 2pm (below) – single-day simulations

Three important results can be drawn from Figure 1:

1. there is a considerable amount of intraday rescheduling that impacts almost all kinds of resources;

2. almost all countries show a change in their net position, meaning that cross border exchanges play an important role in mitigating the impact of NP-RES forecast errors;
3. in some countries, the upward flexibility is provided mostly by fossil-fueled resources.

Focusing on point 2, for some countries, the single-day simulations show that cross-border trades are the main source of adjustment. For instance, the aggregated export/import volumes are 90GWh for both UK and Germany and 40GWh for both Italy and Spain. It is also interesting to note that in one setting of the single-day simulations where forecasts were updated only in one country, the impact on the dispatch and net positions of its neighbours was still very significant.

This has different implications for European countries. First, hourly DA prices within a country does not only depend on the electricity mix but also on the neighboring countries' share of renewables. For instance, the French day-ahead price does not always occur with high RES generation because. An example of this is shown in Figure 2, taken from the results of the nodal one-year simulations (Subsection 3.3 of D2.4), where the hourly average prices in France and Germany for a week with high demand are shown along with the hourly generation mix. Prices vary largely in France even if generation is quite smooth compared to the situation in Germany; generation spikes, except for the typical pattern of PVs, come from gas-fired units and correspond to the spikes in price (which follow marginal costs, be it in the country itself or in neighbouring countries):

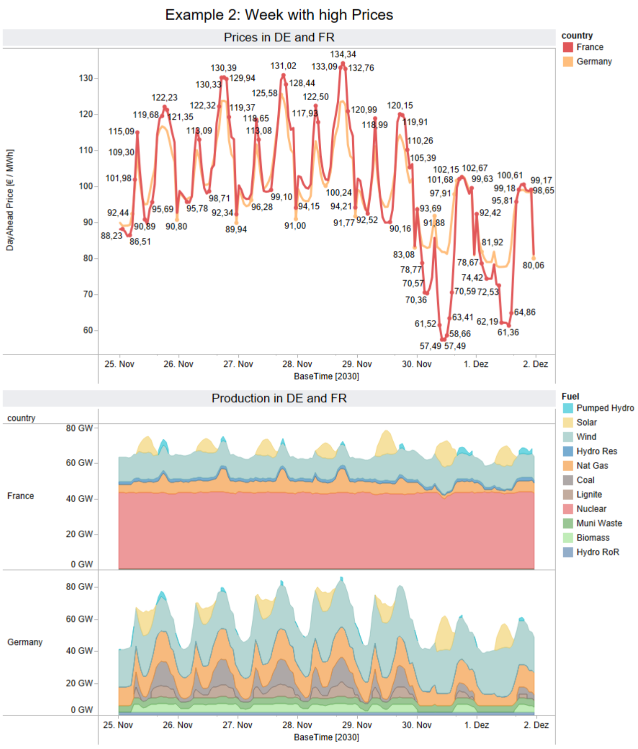


Figure 2: hourly prices and generation profiles in France and Germany for a high demand week in November – nodal one-year simualtions

Intuitively, this situation may happen more often as the share or renewable generation increases.

Second, adjustments by cross-border import/export can lead to a change in conventional generation within a country; it can be either an increase or a decrease, and if no bias in RES forecast is present, over one year the positive and negative error should almost neglect. But the system operation is not linear – due to the presence of RES curtailment and the technical constraints of conventional generation, thus, as a consequence, CO_2 emissions in future scenarios could be underestimated. Furthermore, as the CO_2 price in the EU-ETS mechanism is expected to grow continuously, the electricity price volatility may increase considerably, as long as fossil-fueled resources are activated to provide flexibility. This situation might further incentivize countries to reduce the share of conventional power plants in their electricity mix in favor of other kinds of flexible resources, such as storage. However, negative forecast errors do not necessarily lead to an increase of conventional generation units if updates in a neighboring country are in opposite signs and cross-border capacities are available.

4.2 The impact of cross-border production adjustments

As already mentioned in the previous section, almost all countries show a change in their net position, leading to the conclusion that cross border exchanges play an important role in mitigating the impact of NP-RES forecast errors. Also, single-day simulations show that forecast errors between DAM and IDM impacted greatly also cross border congestions, as it is depicted in Figure 3.

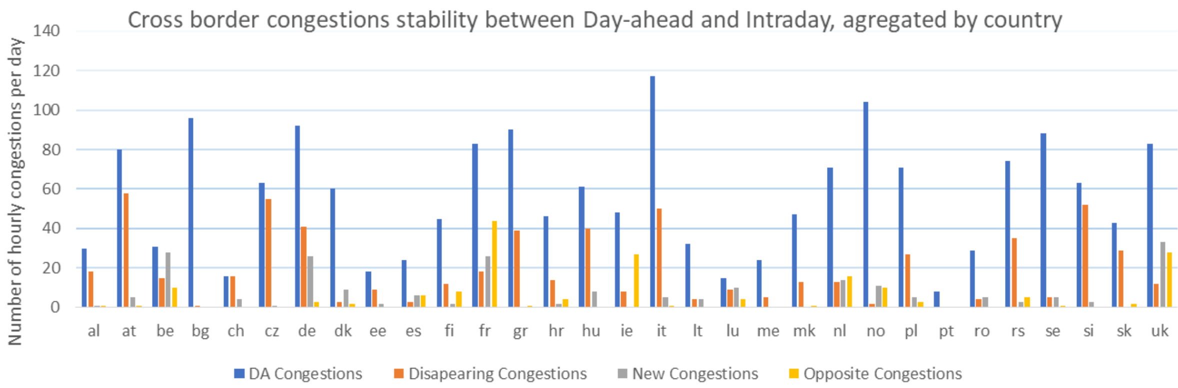


Figure 3: Evolution of cross-border congestions between the DA and ID markets, aggregated by country – zonal single-day simulations

Then, it is evident that cross-border network operation for DA and ID markets has to take these consequences of a large share of RES generation carefully into account. This is particularly relevant for the flow-based DA and ID market configuration, with the flow-based DA market becoming the standard for almost all Europe in the next years. Indeed, flow based domains are optimised for a certain direction of the market 1 or 2 days in advance when RES generation are highly uncertain.

4.3 Recommendations

What is discussed in this section leads to the following considerations.

Power system investment planning should not focus only on the national electricity mix. Indeed, it should be based on a deep coordination among neighboring countries. This is a quite strong regulatory implication, since the high level of interconnection among national power systems in Europe implies that the investments would be more effective – in general and in terms of green-house gas emission reduction in particular – if largely coordinated. Since compensating for forecast errors proves to be an interesting added value of interconnection, this benefit should be taken into account in the cost-benefit analysis of future projects.

The important role played, according to the simulations results, by interconnections, both national and cross-border, for the mitigation of the effects of uncertainty, confirms the importance of TSO-TSO coordination in terms of System operation. Which is already at high levels in Europe, but could even be strengthened. One important example of this is related to the definition of cross-border capacity for DA market clearing. This is important in particular if the flow-based configuration is applied. In this case, the PTDF coefficients should be properly determined; a possible, effective approach is provided by the work of Emily Little (Little et. al, tbp).

Similarly, in long-term studies, the modeling of cross-border capacity calculation should also take into account the impact of the uncertainty resulting from NP-RES forecast errors.

5 Remarks on the Nodal Market Configuration

The single-day simulations and the one-year simulations described in D2.4 have been performed considering both a zonal market configuration and a nodal market configuration. The following remarks and considerations on the profitability of electro-chemical storage systems (batteries in the following) are derived from the comparison of the obtained results.

It is well known that a storage charging-and-discharging pattern is driven by the ratio between highest and lowest prices compared with the efficiency of charging and discharging. Usually, batteries have a daily operation cycle, since their duration (that is, the ratio between capacity and power) is commonly lower than 8 hours. Thus, for batteries, the charging and discharging pattern is strictly related to the daily price volatility.

Given these considerations, the one-year simulations under nodal market configuration provided an interesting result, that can be easily observed in Figure 4, which is built by mixing three figures taken from Sections 3.3 and 3.4 of D2.4. The two upper maps show respectively the nodal renewable generation mix (left) and the nodal demand (right). The lower left map shows the average nodal prices and the lower right map shows the revenues for batteries in function of the node they are connected to.

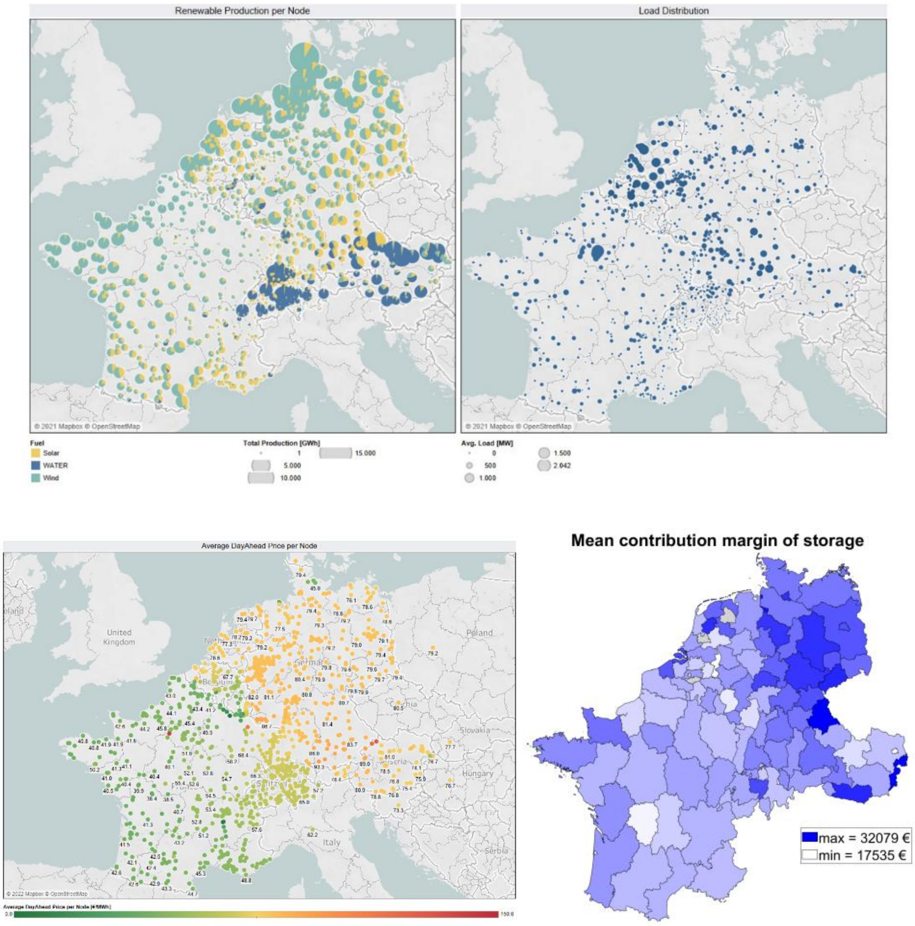


Figure 4: Highlights on storage profitability in a nodal market framework

It is quite evident that the nodes with the highest NP-RES share, that is the coastal nodes in Germany, are not the ones where batteries make the largest profits. Instead, the largest profits are made by batteries in particular in the nodes of the German system characterized by high daily price variations (often due to high PV capacity) – as clearly shown by results provided by the single-day and the one-year simulations, both under zonal and nodal market configuration – and high average prices. Obviously, this is a consequence of the already mentioned low duration of batteries that make them particularly suitable to respond to the daily profiles of price variations. Since load and PV have "natural" daily patterns, batteries result to be more profitable if installed close to them. Wind generation, on the contrary, usually has not such a daily pattern, thus to reduce Wind curtailment either other kinds of storage technologies – characterized by a long duration, maybe also seasonal – have to be considered, or new remuneration frameworks for batteries have to be considered.

Storage in general, and batteries in particular, are potentially highly helpful in creating more value from the energy generated by NP-RES – to reduce generation volatility; to reduce the waste of almost free and totally carbon free energy; etc. A suitable framework is essential to capture this value.

Another implication is the choice of battery capacity. The simulations show that the earnings of battery units increase with capacity but at a decreasing rate. Moreover, by considering an investment cost of 200€/kWh for storage, the investment would break even in 10 years. This represents the median value with significant variations across countries. However, revenues from other markets are not considered but the results show that price variations within the day drive profitability.

5.1 Recommendations

As a consequence of what has been discussed above, if the investment decisions on storage systems – on batteries in particular – are based only on the economic profitability in the wholesale markets, we may miss their profitable contribution to solve congestions, possibly limiting the penetration of RES. Thus, other kinds of remuneration mechanisms for batteries and storage should be taken into account to reflect the value they can provide to congestion management and, by removing these limits to RES exploitation, to the energy transition.

The lack of locational investment signal in the past two decades has led to significant issues, concentrating renewable development in some areas and leading to important congestion levels. Nodal pricing has often been proposed as a solution. While it could potentially be a useful tool to provide a short-term price signal highlighting the need for local flexibility, it remains to be seen whether it could act as a useful investment signal. Note that the inability of investors to anticipate long-term market prices is a problem both in zonal and nodal settings, and that in recent decades, investment/decommissioning of new generation and storage in Europe has primarily been decided by the public sector/enabled by public subsidies based on environmental concerns, not market prices. Nevertheless, nodal prices remain particularly sensitive to local RES development or grid reinforcements. It is also worth mentioning that nodal pricing is not the only way of sending a locational investment signal: location-dependent grid charges, local tenders or local support mechanisms could also play that role.

Regarding nodal pricing, if the market concentration is high in a node, market power can occur but several options exist to mitigate such behavior (see Graph et al., 2021). Second, the price volatility is usually higher in nodal pricing than in zonal system but as the results show, it might not be true with the increasing share of renewables. Further analysis should be made to assess the price volatility level between these zonal and nodal systems. Note that market liquidity is not necessarily low in nodal markets (Eicke and Schittekatte, 2022). Third, the investment decision does not depend only on the localization signal according to Brown et al (2020). Further investigation into the factors of investment decisions should be carried out.

6 TSO-DSO coordination

The results of the “DN simulations” show that the availability of the flexibility provided by resources connected at the distribution level is strongly impacted by the limits of the distribution network. The position of distributed resources along the distribution network is crucial since, on the one side, it might favor or contrast the formation of network congestions, which, on the other side, may reduce the flexibility provided to the System.

In particular, Figure 5 – taken from Subsection 9.1.3 of D2.4 – shows two scenarios applied to the same network. The upper graph of the figure shows the case in which the DERs are widespread in the network. Such configuration may reduce the potential flexibility, but the offers that negatively impact the distribution network operation are limited (i.e., part of the upward bids and a small part of downward ones). On the contrary, if the distributed resources are concentrated in a few portions of the network, the available flexibility is much more reduced even concerning the downward bids (lower graph of Figure 5).

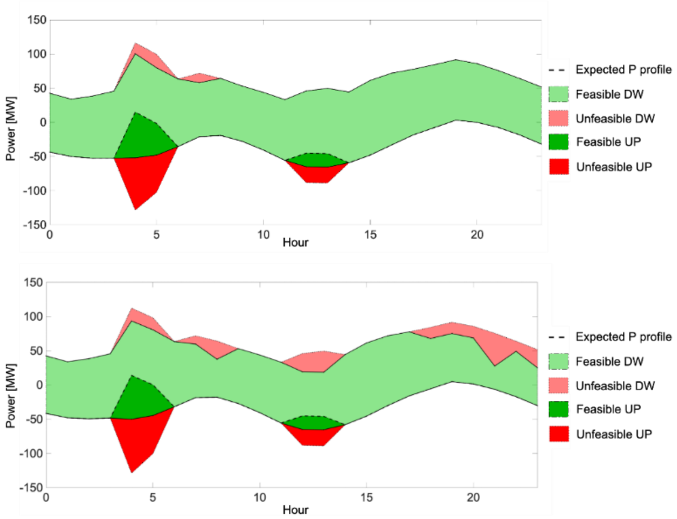


Figure 5: Hourly flexibility available from distributed resources in an autumn working day in a “dispersed installation” configuration (upper) and in a “concentrated installation” configuration (lower) – DN simulations

This result adds another level of complexity for assessing the impact of the forecast errors. And this is of primary importance, since the number of flexibility resources, in particular, flexible demand and storage devices, connected to distribution is expected to grow more and more in the next decades. Then, several implications follow.

First, new mechanisms should be implemented in order to incentivize flexibility providers to minimize grid constraints. These mechanisms could be set in accordance with the ones discussed in Subsection 5.1. And furthermore, they should take into account the implications for price volatility and so for the market parties’ strategies.

Second, in order to use the distributed source of flexibilities efficiently, TSO/DSO coordination must be strengthened. One major issue with TSO/DSO coordination is data sharing and especially the information on the grid constraints. Grid operators might be reluctant to share non-public information such as the network topology. The methodology used in the DN simulations allows us to represent the grid constraints with open data through synthetic networks, thus overtaking data sharing issues in the assessment of the value of distributed flexibility for the system. Also, it enables to represent the grid constraints without using DSOs' non-public information.

Third, to assess the impact of forecast errors on the system accurately, the actual revenues coming from the participation in the ID market for the distributed flexibilities should be assessed and compared to those coming for other purposes, such as distribution network balancing and or congestion management.

7 Final remarks

In the previous sections, the results of the simulations described in D2.4 have been analysed and discussed in order to draw some remarks and recommendations on four specific topics: the impact of uncertainty on market strategies, the impact of uncertainty on cross-border interconnection operation, the nodal market configuration and the flexibility connected at the distribution level.

However, the complexity of the problem of the simulation of the European power system, with an hourly detail and a yearly time horizon or a market agent methodology, and their computational cost allowed to analyse only one single scenario. Thus, the results obtained in terms of regulatory recommendations are unavoidably limited. However, this work lay the foundations for future possible analyses; for instance, it could be interesting:

- to consider different levels of NP-RES penetration;
- to consider different levels of flexibility at the distribution level;

to consider higher coordination levels between national power systems in terms of generation mix definition and/or cross-border interconnection development.

8 References

Acemoglu, D., Kakhbod, A., Ozdaglar, A., 2017. Competition in Electricity Markets with Renewable Energy Sources. EJ 38. https://doi.org/10.5547/01956574.38.SI1.dace

Brown, D.P., Zarnikau, J., Woo, C.-K., 2020. Does locational marginal pricing impact generation investment location decisions? An analysis of Texas's wholesale electricity market. J Regul Econ 58, 99–140. https://doi.org/10.1007/s11149-020-09413-0

Eicke, A., Ruhnau, O., Hirth, L., 2021. Electricity balancing as a market equilibrium: An instrument-based estimation of supply and demand for imbalance energy. Energy Economics 102, 105455. https://doi.org/10.1016/j.eneco.2021.105455

Eicke, A., Schittekatte, T., 2022. Fighting the wrong battle? A critical assessment of arguments against nodal electricity prices in the European debate. An MIT ENergy Initiative Working Paper.

Graph, C., La Pera, E., Quaglia, F., Wolak, F., 2021. Market Power Mitigation Mechanisms for Wholesale Electricity Markets: Status Quo and Challenges. Working Paper Stanford University.

Just, S., Weber, C. (2015): Strategic behavior in the German balancing energy mechanism: incentives, evidence, costs and solutions. In: Journal of Regulatory Economics 48(2), S. 218-243

Lago, J., Marcjasz, G., De Schutter, B., Weron, R., 2021. Forecasting day-ahead electricity prices: A review of state-of-the-art algorithms, best practices and an open-access benchmark. Applied Energy 293, 116983. https://doi.org/10.1016/j.apenergy.2021.116983

Little, E., Atay, A., Bourmand, J.Y., Bortolotti, S., Cosson, M., Karangelos, E., Perez, Y., t.b.p., Enlarging the Flow-Based Domain in the European Day-Ahead Market Clearing through the Full Integration of Grid Flexibilities and Costly Remedial Actions.

Wozabal, D., Graf, C. & Hirschmann, D. The effect of intermittent renewables on the electricity price variance. OR Spectrum 38, 687–709 (2016). https://doi.org/10.1007/s00291-015-0395-x