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Impact analysis of market and regulatory options through advanced power system and market modelling studies

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EU-SysFlex

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ABBREVIATIONS AND ACRONYMS

aFRR	Automatic Frequency Restoration Reserves
BE	Balancing Energy
CO	Critical Outage
CWE	Central Western European
CZC	Cross-Zonal Capacity
DAM	Day-Ahead Market
DER	Distributed Energy Resource
DSO	Distribution System Operator
DUDI	Demand Utility Deviation Index
EC	European Commission
ED	Economic Dispatch
ENS	Energy Not Served
ENTSO-E	European Network of Transmission System Operators for Electricity
ERCOT	Electric Reliability Council of Texas
ESS	Energy Storage System
EU	European Union
EU-SYSFLEX	Pan-European System with an efficient coordinated use of flexibilities for the integration of a large share of Renewable Energy Sources (RES)
FCR	Frequency Containtment Reserves
FFR	Fast Frequency Response
FRR	Frequency Restoration Reserves
GPDI	Generation Profit Deviation Index
KKT	Karush-Kuhn-Tucker
LL	Lower Level
LMP	Locational Marginal Price
LODF	line outage distribution factors
mFRR	Manual Frequency Restoration Reserves
MII	Market Inefficiency Index
MILP	Mixed-Integer Linear Program
MISO	Midcontinent Independent System Operator
MPEC	Mathematical Program with Equilibrium Constraints
MRA	Multilateral Remedial Action
NYISO	New York Independent System Operator
OCGT	Open Cycle Gas Turbine
PJM	Pennsylvania, Jersey, Maryland Power Pool
PST	Phase-Shifting Transformer
PV	Photo-Voltaic pannels
PV	Photovoltaic, relating to solar photovoltaic energy sources
RA	Remedial action
RD	Redispatch
RDCT	Redispatch and Counter Trading
RES	Renewable Energy Sources
RPCD	Reserve Procurement Contract Duration
RPF	Reserve Procurement Frequency

RR	Replacement Reserves
RSF	Reserve Sizing Frequency
RSR	Reserve Sizing Resolution
SNSP	System Non-Synchrnous Penetration
SOGL	System Operation Guideline
TSO	Transmission System Operator
UC	Unit Commitment
UCTE	Union for the Coordination of Transmission of Electricity
UL	Upper Level
vRES	Variable Renewable Energy Sources
WP	Work Package
XB	Cross-border
XBR	Cross-Border Redispatch

EXECUTIVE SUMMARY

With the advent of very high levels of variable renewable generation, as well as a move to more decentralised and distributed power electronics-interfaced technologies, power systems will face significant technical and financial challenges. Within the EU-SysFlex project, these challenges have been studied in the context of installed capacities of renewables that succeed in meeting up to and over 50% of the total annual electricity demand. In that context, a number of key technical scarcities arise: the need for system services increases, the conventional supply of system services decreases, and network constraints become more urgent, both at the transmission and distribution level. In order to maintain the security and stability of the power system, new and innovative system services may be required, new service providers need to have a route to market, and novel remuneration mechanisms and innovative market designs have to be explored.

Work Package 3 of the EU-SysFlex project focused on the analysis of market design and regulatory options for innovative system services that can help address the challenges associated with the integration of very high levels of variable renewable generation. Within the work package, Task 3.4 focused on complementing the conceptual market designs coming out of Task 3.2 with advanced power system and market modelling studies, considering both the long-term (investment) and short-term (operational) impacts of these designs on the pan-European power system. This allowed to analyse how different designs played out across different operational timeframes (seconds, minutes, hours) and different power system configurations (distribution vs. transmission level, isolated vs. interconnected, lightly-loaded vs. congested grids, etc.).

This report provides an overview of the outcomes from the different quantitative and model-based analyses of specific market or regulatory design options for a cost-efficient provision of system services in high-RES electricity systems. Several key messages come to the fore across the different research efforts. First, the research in this report shows that improvements in market design can facilitate the sustainability transition. Second, it provides evidence of specific ways that regulation and market design can do so. The implementation of shorter-term, higher resolution ancillary service markets reduces the cost of ensuring system reliability, among other things by enabling the participation of nonconventional providers such as demand response and variables renewables. Additionally, cross-border coordination in both markets and system management (e.g., cross-border congestion management) further reduces the cost of ensuring system reliability. Third, the research calls attention to key challenges for regulation and market design. New market power effects associated with new service providers and technical constraints need to be understood in more detail. In addition, system service markets have to provide sufficiently stable investment signals such that the required flexibility will be developed. Finally, all research indicates that these effects become increasingly significant as renewable shares grow. This clearly points to the importance of action being taken sooner rather than later.

The following sections of the executive summary present the main findings and conclusions of all research efforts performed within Task 3.4. The full analyses are presented in the different chapters of this report:

- **Chapter 3**: Enhancing TSO-DSO integration to facilitate market access for distributed energy resources
- **Chapter 4**: Interdependence of energy and reserve markets in high-RES systems
- **Chapter 5**: On the temporal granularity of joint energy-reserve markets in a high-RES systems
- **Chapter 6**: Benefits of regional coordination of balancing capacity markets in future European power markets
- **Chapter 7**: Pre-selection of the optimal siting of phase-shifting transformers based on an optimization problem solved within a coordinated cross-border congestion management process
- **Chapter 8**: Defining the TSO's investment shares for PSTs used for coordinated redispatch
- **Chapter 9**: Increasing technology neutrality in service markets in power systems with high RES shares
- **Chapter 10**: Analysis of long-term investment signals provided by ancillary services markets
- **Chapter 11**: Impacts of flexibility and unit commitment characteristics on market power effects

ENHANCING TSO-DSO INTEGRATION TO FACILITATE MARKET ACCESS FOR DISTRIBUTED ENERGY RESOURCES

The role of distribution system operators (DSOs) needs to evolve to maximise the use of Distributed Energy Resources (DER) services not only for local distribution network management but also for the benefit to the wider transmission system**.** Operational challenges arise as the use of DER by different operators may trigger conflicts between serving the local or national or regional objectives. It indicates that stronger TSO-DSO coordination is required to maximise the synergy of using distributed resources to provide multiple services. In this context, the work investigates two coordination approaches, i.e. incremental and whole-system technical and commercial frameworks to bridge and enhance the TSO-DSO's integration while enabling the maximum use of DER and stimulating competition in the provision of transmission services by the local DER and transmission connected generators on a level of playing field. A range of case studies was performed to analyse the performances of the two approaches and the drivers for the optimal solution.

First, the incremental coordination approach is based on the principle that DSOs have the priority to use DER services to solve distribution network problems and then facilitate the remaining capacity of DER services to be offered to the wholesale electricity markets (both energy and ancillary services). DSOs ensure that the utilisation of the offered capacity does not violate distribution network constraints. In this context, the concept of Virtual Power Plant (VPP) is used to aggregate the capacity and energy that can be harnessed from DERs while ensuring secured distribution network operation. Local electricity (energy and ancillary service) markets can be developed to promote competition between local resources to stimulate cost-efficient operation.

The studies demonstrate that the use of smart distribution grid technologies (e.g. wide area system voltage optimisation) is vital to allow: (i) minimum use of the resources for solving distribution problems and therefore, it minimises not only the distribution's operation cost but also the contracted capacity needed, and (ii) optimal access for the remaining DER capacity to be used for transmission and balancing services at the national level. In addition to the capacity provided by DERs, distribution network assets can also be used to provide services to transmission[1]. By controlling distributed reactive compensation, and at some extent, the active and reactive power losses at distribution, the power flows at the TSO and DSO coupling points can be adjusted to meet the national electricity system requirements.

The second approach is to optimise the use of DER capacities for TSO and DSOs simultaneously. In principle, this optimises all connected plants at transmission and distribution concurrently. From the optimality point of view, this approach is the ideal one; however, it is very challenging for the computation and for the control. The second approach leads to the need of having centralised electricity markets for all plants (including DERs)[2] and centralised system operation. It requires a central entity that integrates the TSO and DSOs system operation fully in order to optimise the whole system and therefore, it may not be compatible with the current operational structure where a TSO focuses on the national transmission system operation while DSOs operate distribution networks.

The performance differences between the first and the second approach can be minimised if the allocation of DERs can be corrected to consider both transmission and distribution requirements during real-time. This can be facilitated if the market operation is close to real-time (e.g. 15 - 30 mins ahead) and the distribution network operation is quite flexible.

INTERDEPENDENCE OF ENERGY AND RESERVE MARKETS IN HIGH-RES SYSTEMS

Energy and reserve markets are linked through the technical constraints of reserve providers, e.g. generation limits of power plants. The use of capacity for reserves (generation, load or storage capacity) constrains the use of that same capacity in the energy market, and vice versa.

Two different market designs are commonly used to organize energy and reserve markets: joint clearing and sequential clearing. In joint markets, energy and reserves clear simultaneously. Interdependencies between both are implicitly accounted for. Joint markets are based on a unit commitment style optimization that dispatches energy and reserves on unit level. Examples of joint markets are the US competitive markets such as PJM, CAISO, ERCOT, MISO and NYISO. In sequential markets, energy and reserves clear sequentially without implicitly accounting for interdependencies. Sequential markets are based on a simple quantity-price optimization that dispatches energy and reserves at portfolio level. Market participants then schedule their units, accounting for interdependencies between energy and reserves. The European Integrated Energy Market is based on sequential market clearing.

[1] Technically, as shown as by the studies, the distribution network assets can be used to support transmission networks. This contribution should be recognised so the assets can be fully utilised. The remuneration mechanism for the use of these assets is out of the scope of the work; this study can be used to trigger further discussions on how the benefits of these assets can be fully integrated in the policy and commercial framework.

[2] The centralised electricity market is a single market place where all providers (small and large) and the users are met. This requires both transmission and distribution models to be considered during the market clearing process to maximise the synergy and prevent conflicts of using DERs for both transmission and distribution needs.

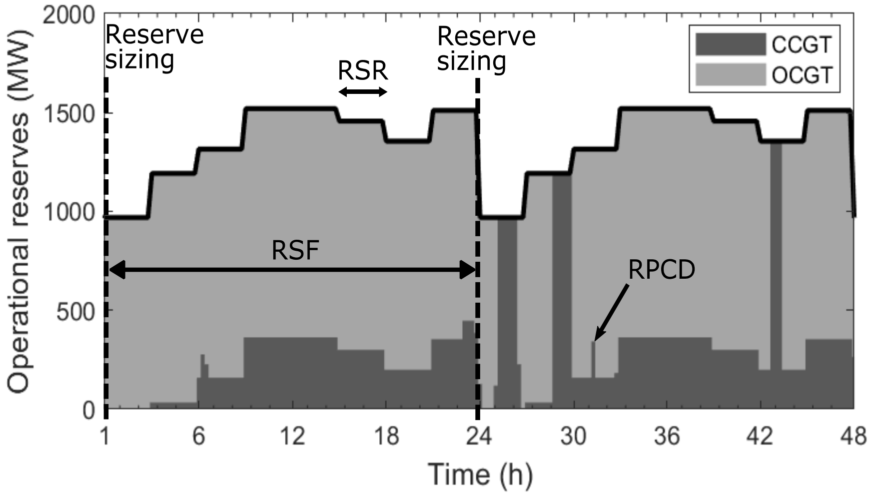
The performance of a sequential and a joint energy-reserve market design is analysed for a realistic and large-scale case study of the Central Western European electricity system and for scenarios with different levels of intermittent renewables. To this end, a detailed unit commitment model is set up that simulates the day-ahead scheduling of energy and reserves, followed by a real-time activation of reserves. The performance is analysed in terms of the total operational system costs. The operational system costs are evaluated for a simulation of a full year and after the real-time reserve activation (i.e., both the cost of reserve allocation and activation is considered).

The cost surplus of sequential vs. joint market clearing increases with increasing levels of wind and solar PV, up to 2.0-2.5% of total operational system cost at 30-35% wind and solar PV. The cost difference also increases in absolute terms, from €58M at 7% share wind and solar PV (on a total operational system cost of €47.5B) to €535M at 33% share wind and solar PV (on a total operational system cost of €23.0B) for a one-year simulation of the CWE region. However, this cost difference between a joint and sequential design can be significantly reduced with decreasing reserve costs through increased participation of flexible load and renewables.

Joint energy-reserve markets are unlikely to become the target market design in a European context in the short-term or near future. However, based on the quantitative results, three implications for the sequential energy and reserve markets in Europe can be derived. First, the additional costs of sequential reserve scheduling is driven by the technical inflexibilities and limitations of conventional power plants (e.g. minimum up/down times). Flexible load and renewables are more flexible in providing reserves, at least from a purely technical perspective. Therefore, reserve market design should be opened up for reserve provision by renewables and flexible load. This could entail a broad set of actions, such as allowing load aggregators to bid in reserve markets or reducing contract durations to enable reserve provision by intermittent generation. Second, as the required level of reserves is assumed in this analysis to increase with the share of wind and solar PV, the additional cost of a sequential market design increases as well. This effect can be partially offset by improving the dimensioning of reserves by, for instance, dynamic reserves and more short term reserve sizing. As such, the need for reserves can be determined more accurately and less reserves need to be scheduled. Third, it is illustrated that the additional cost of sequential clearing has a more than linear relation with the level of wind and solar PV. In other words, the cost difference becomes larger with increasing wind and solar PV, and at an increasing rate. This implies that the above implications are preferably taken into account sooner than later. The analysis shows clearly that there is a cost of not acting or acting late.

ON THE TEMPORAL GRANULARITY OF JOINT ENERGY-RESERVE MARKETS IN A HIGH-RES SYSTEM

Transmission system operators (TSOs) procure flexibility in the form of balancing capacity/operating reserves. The temporal granularity of these markets for balancing capacity/reserves can be characterized by the frequency of sizing reserve requirements and the corresponding resolution, and the frequency and resolution at which the required reserves are procured. This is illustrated in the Figure below.



In today's European reserve markets, reserves (i.e., FCR, FRR and RR) are typically sized and procured on yearly, monthly, weekly or daily basis. Moreover, the contract duration for reserve products is, in some countries, e.g., Belgium and The Netherlands, restricted to weekly or monthly products. However, a higher temporal resolution (e.g., daily sizing and procurement of hourly products) has the potential to lower the cost of reserves.

The potential benefits to cost-efficiency (and hence welfare) and reserve market liquidity of adopting increasingly more dynamic temporal granularities of reserve markets are quantified for a case study of the Belgium electricity system and for the Energy Transition and Renewable Ambition EU-SysFlex scenarios. Quantifications are based on a unit commitment and economic dispatch (UC) model that is designed to simulate the impact of the temporal granularity of reserve markets. Concretely, we analyze the impact of the following four considered temporal aspects of reserve markets:

1. **The reserve sizing frequency** (RSF) specifies how regularly reserves are sized
2. **The reserve sizing resolution** (RSR) sets the duration of blocks
3. **The reserve procurement frequency** (RPF) sets how regularly reserves are procured
4. **The reserve procurement contract duration** (RPCD) specifies the resolution of reserve products, being allocated at unit level (i.e., length of the procurement blocks)

First, more frequent reserve sizing and procurement will allow employing improved forecasts as the lead time between forecast creation and actual realization decreases. Hence, the real-time operating reserve requirements are reduced, which could yield operating cost savings while maintaining the system's security. Second, increasing the temporal resolution of reserve markets allows more cost-efficient, dynamic sizing of reserves. Third, a short contract duration allows accounting for the time-dependent availability of reserve providers (particularly important for intermittent sources such as wind and solar PV, and certain types of responsive load), as well as the time-dependent opportunity cost of offering capacity in reserve markets (particularly relevant for thermal generators).

Results of the two realistic case studies revealed that the total operating cost savings reach 1.5% to 1.8% when moving from a very conservative (i.e., sizing well in advance, daily procurement and daily reserve contracts) to a highly dynamic (i.e., sizing and procurement close to real-time with quarter-hourly resolution) joint energy-reserve and balancing market. Equally, adopting higher temporal granularities mitigated reserve market scarcity. More frequent reserve sizing with a higher reserve requirement resolution resulted in total cost-savings of 0.75-1.10%. Reducing the reserve procurement contract duration and procuring reserve capacity more frequently yielded cost savings of 0.75% and facilitated the integration of intermittent renewables in reserve markets. From a practical viewpoint, more frequent reserve sizing and procurement could pose challenges related to market operation. However, it is debatable whether they weigh up to the considerable benefits of the market design changes investigated in this work.

The policy implication of this work is clear: implement shorter term, higher resolution reserve markets. Our work supports recommendations put forward in Article 32 of Commission Regulation (EU) 2017/2195, encouraging reserve procurement on a short-term basis (close to delivery and with high-resolution products) to the extent possible and where economically efficient.

BENEFITS OF REGIONAL COORDINATION OF BALANCING CAPACITY MARKETS IN FUTURE EUROPEAN ELECTRICITY MARKETS

Driven by concerns regarding market concentration in balancing markets and the expected increase of less predictable generation from variable renewable energy sources, the importance of extending market integration to realize cross-border balancing is growing. Recent European regulation (cfr. *Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast)*) recognizes there is a need to foster market integration to allow transmission system operators (TSOs) to procure and use balancing capacity in a cost-effective and market-based manner.

Different levels of balancing market integration can be distinguished, with increasing levels of coordination (where each level implies an additional element of coordination to the previous level):

(1) **Coordination of the real-time activation of balancing energy** through:
    a. Imbalance netting: TSOs exchange opposing imbalances before using balancing energy (BE).
    b. Using a common merit order list: TSOs use a common merit order list of BE bids such that BE is provided at the lowest cost, which implies the exchange of BE between zones.

(2) **Coordination of the procurement/contracting/allocation of balancing capacity** through the exchange of balancing capacity (BC), which implies the contracting of BC located in different control zones.

(3) **Coordination of the sizing of balancing capacity requirements** through the sizing of BC for a certain region (spanning multiple control zones) and the sharing of BC within that region (i.e. multiple TSOs rely on the same BC for meeting their local BC requirements).

Coordinating the procurement and sizing of BC is more complex than the coordination of the activation of BE. Since the coordination of the activation of BE happens in real-time, the status of the network is known, and the remaining cross-zonal capacity (CZC) can be used for the exchange of BE. In contrast, as procuring BC happens before real-time, the exact state of the network is not known. Hence, to ensure the real-time deliverability of BC located in a different zone, it needs to be guaranteed that the required CZC will be effectively available.

This requirement of reserving CZC for BC invites an investigation of the potential benefits of using CZC for exchanging or sharing BC in addition to using it for the trade of electricity on day-ahead energy markets. These benefits were assessed for case studies based on the Central-Western European system with power system portfolios based on the EU-SysFlex Scenarios: Energy Transition and Renewable Ambition. A model was developed with detailed technical constraints to simulate the co-optimized allocation process of CZC for BC exchange and sharing in a joint day-ahead energy and BC market clearing. The activation of BE in real-time is assumed to be fully coordinated. BC exchange and sharing were modelled following the mechanisms outlined in ENTSO-E's 2019 All TSOs' proposal on this subject.

Hourly simulations results for a week-long period illustrate how cross-border coordination of BC markets can lead to a more cost-efficient power system operation. First, the provision of BC itself is more efficient. When cheaper BC is available in neighbouring control zones, BC exchange allows for the import of that capacity (and vice versa). This effect is only partially captured in this work, as a clustered unit commitment approach is employed, which trades off significant plant-level detail (modelling clusters of a technology rather than individual units) for increased computational performance. However, it is expected to be less relevant for studies looking 10 or more years ahead.

Second, cross-border coordination enables increased generation from less flexible capacity, both "slow" conventional and renewable technologies, which is often cheaper. This happens because BC exchange allows to import flexibility from other control areas, thus reducing the technical constraints on online capacity within a control area. This can free up low-marginal cost capacity initially (partly) allocated to provide BC, allow increased contributions from low-marginal cost, low-flexibility capacity, and even reduce curtailment at times of high renewable output. As the stringency of flexibility requirements varies in time and place, different control areas can benefit from these effects at different times. The benefits of a coordinated approach are greater as the share of renewables is higher.

Third, cross-border coordination allows to reduce the overall need for BC. This has the potential to drive the most significant cost savings. On the one hand, it allows for a reinforced version of the second effect described here, i.e. lowering the technical constraints on the power system portfolios, thus allowing for more low-marginal cost capacity to be used for electricity generation. On the other hand, and probably more significantly, it allows to simply build less "back-up capacity". Unfortunately, this effect was not captured clearly here, as the EU-SysFlex scenarios have quite a lot of flexible capacity. Nevertheless, studying the trade-off between building more back-up capacity vs. building less but sharing more of it between control areas through reinforced cross-border connections is a key task for researchers working to understand the benefits of cross-border BC coordination; especially given that also here those benefits are anticipated to be greater for higher shares of renewables.

PRE-SELECTION OF THE OPTIMAL SITING OF PHASE-SHIFTING TRANSFORMERS BASED ON AN OPTIMIZATION PROBLEM SOLVED WITHIN A COORDINATED CROSS-BORDER CONGESTION MANAGEMENT PROCESS & DEFINING THE TSO'S INVESTMENT SHARES FOR PSTS USED FOR COORDINATED REDISPATCH

The cross-border problems related to congestion management in the European synchronous grid are solved by transmission system operators (TSOs). One of the reasons of the cross-border congestion management originates from the discrepancies between the market solution and physical flows, causing, in particular, the occurrence of unscheduled cross-border flows. The TSOs have a defined protocol of actions in order to solve those congestions, however this process is far from being automatic – it involves expert-based decision making and direct communication between the dispatch offices of particular TSOs.

Moreover, the aforementioned protocols provide a prioritization of different actions that the TSO can perform. First, TSOs would try to solve those internal problems by costless remedial actions such as changing the PST tap settings. Afterwards, if the problem persisted, the TSO would consider applying the so-called XBR (Cross-Border Redispatch), that is, coordinated redispatch of generators on both sides of the cross-border line at which the congestion occurred. However, redispatch capabilities of generators are limited, and in some situations it is necessary to involve other TSO(s) to apply MRA (Multilateral Remedial Actions), which include redispatching of generators operated by TSOs further from the congested border. The whole process is driven similarly to XBR nonetheless involving more than two TSOs. Obviously, redispatching in the form of XBR and/or MRA is costly and currently in Europe there is no universal rule governing the XBR and MRA cost-sharing between TSOs – the costs are covered on the basis of bilateral and multilateral agreements, and although TSOs have started to develop a common framework of cost-sharing, the process is far from being finalized.

The limitations of the current procedure are associated with the fact that the cross-border remedial actions are not coordinated across a wider area. For example, changing PSTs tap settings to counteract one cross-border congestion can have negative influence on congestions governed by other TSOs. Moreover, applying XBR/MRA measures individually by each TSO to counteract each congestion can be very costly. Instead, seeking an effective direction of redispatching between many TSOs could reduce the total cost of remedial actions in the whole coordinated area.

To this day, the TSOs do not operate any coordination tool that would allow them to perform the necessary remedial actions for the whole European synchronous area at once and in the most effective way. However, the most effective remedial actions could be based on redispatching the generation in a country different than the ones having congestion problems. From the global welfare point of view, it is a good solution. Nevertheless, from the individual TSO's point of view, it might not be justified if their costly redispatching is used to counteract a congestion in other TSO's region. Thus, a global coordination of remedial actions cannot be effective without accompanying fair rules of splitting their costs – in other words, the cost-sharing methodology must incentivize TSOs to be involved in the global cost optimization.

As a result, the EU is establishing the required mechanisms that could allow designing coordinated remedial actions, as defined in the Article 76 of Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (Official Journal of the European Union L 220/1) and Article 35 of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (Official Journal of the European Union L 197/24). Those mechanism are part of the task related to the RCC role.

The coordination of the cross-border remedial actions has been implemented in the form of an optimization problem and applied to power system models prepared within EU-SysFlex. The coordination tool proves the feasibility and potential for cross-border congestion management. Therefore, in this new framework, TSOs may examine increasing the ability to use more costless remedial actions, in particular by installing new PSTs – this idea is the main research focus of this topic.

Currently, PST investment decisions are supported by cost-benefit analyses, individually per PST candidate. However, the selection of candidates for further analysis is usually expert-based. On the other hand, applying the cross-border coordination optimization problem to analyse long-term scenarios provides valuable information like the potential of particular locations for reducing the overall cost of the congestion management with the means of a PST. The work proposes two methods of such PST candidates identification, namely: the *multiplier indicator* and the *congestion factor*. Both are based on the information extracted from dual variables of the optimization problem and the level of overloads, respectively, to suggest the identification and ranking of the locations for the PST investments.

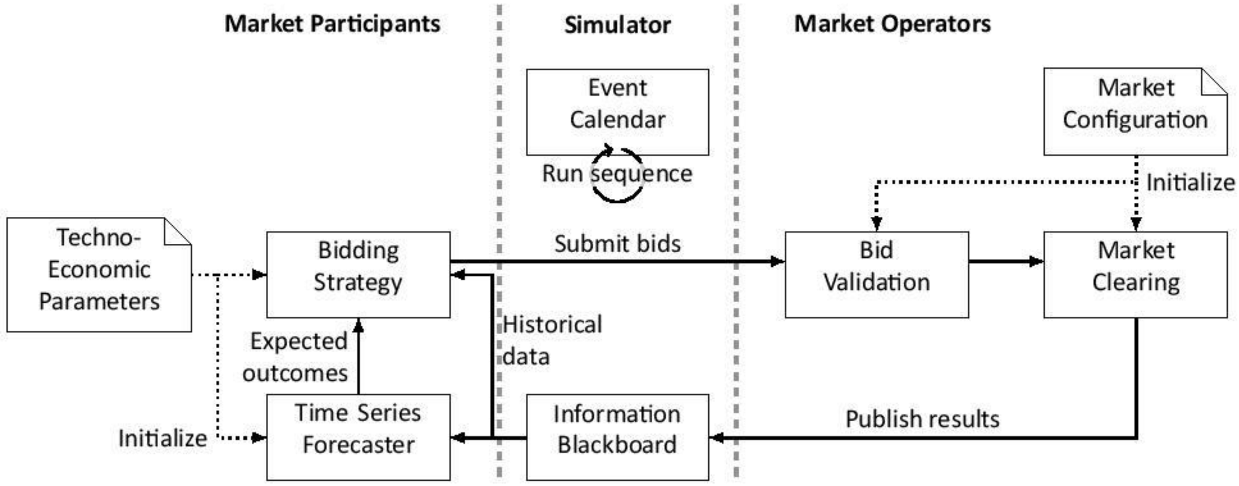
A cost-sharing methodology was implemented within this EU-SysFlex task, along the coordinated cross-border optimization. The methodology is based on the “polluter-pays” principle, which is accepted among TSOs in Europe. This principle allows penalising TSOs’ control areas responsible for causing the congestions, identified by performing the load flow decomposition, in this case based on the Power Flow Colouring methodology. In conclusion, the application of cost-sharing methods to long-term cost-benefit analyses of potential investments shows several interesting indicators for TSOs. Theoretically, the PST or other new investment can bring more savings to some distant zones than to the control area in which the investment is located. Various indicators have been proposed to open the discussion about joint investments: How should the investment cost be divided between TSOs? Are the savings from redispatch great enough to compensate the investment cost?

INCREASING TECHNOLOGY NEUTRALITY IN SERVICE MARKETS IN POWER SYSTEMS WITH HIGH RES SHARES

This study focuses on the challenges to accommodate high shares of RES while maintaining frequency stability of the power grid. One of the ways to tackle the frequency stability issue is through enhanced market design. In particular, dealing with more frequent and larger deviations from the standard frequency implies that greater levels of ancillary services associated with balancing demand and supply across all time horizons will be required. Unfortunately, wind and solar generators only contribute in a limited way to ancillary services in many countries, which limits further the system's ability to accommodate RES. However, an increasing body of literature shows that the participation of RES in ancillary services is technically feasible, although with some restrictions to guarantee security and stability. This shows that there is a gap between, on the one hand, the technical potential of technologies, which refers to the technical ability to deliver system services, and, on the other hand, the market potential, which translates the technical potential into economic value.

In this specific study, we looked at how the shortening of the procurement cycle of mFRR influences the participation of wind technology in the mFRR, and by consequence, the day-ahead market. The study complements Chapter 5 of this deliverable (i.e., “On the temporal granularity of joint energy-reserve markets in a high-RES system”). More specifically, while Chapter 5 focused on and confirmed the technical potential of RES to participate in service markets, our study looked at how this technical potential can be translated into market potential. More specifically, twelve scenarios were investigated depending on the selection of (i) the two EU-SysFlex scenarios (Energy Transition and Renewable Ambition), (ii) the frequency of mFRR procurement (daily, weekly, monthly), and (iii) the future need for mFRR as defined by the Belgian TSO, Elia (low and high need, both for mFRR up and mFRR down). This impact was then analysed by comparing, amongst others, the aggregated cost and the average offered supply/demand for the different markets (i.e., day-ahead, mFRR up and mFRR down). We looked at the simulation results from a system’s as well as a technologies perspective.

To find an answer to our research question, a sequential market simulation tool was developed. The backbone of the simulation is the capturing of the market time sequence and consequently mapping the different decisions taken by the market participants as well as market operators. The main actors are the simulator, market operator and market participant. While the latter two are also actors in reality, the simulator is virtually in control of the execution of the event calendar and the flow of information. Another key element of the market simulator is a blackboard for market information. It is put in place to control the flow of information among individual market participants and market operators. This is to define specific scenarios linked to sharing information. To make the bidding strategies more realistic, forecasting relevant information for the decision-making is incorporated in the simulation. At the moment, this is linked to forecasting time series for prices and availability of generation units including the underlying weather data.



The results indicate that, from a system's perspective, large cost savings can only be achieved by reducing the procurement cycle to daily auctions; changing from monthly to weekly auctions only reduces the cost in a limited way. When it comes to the technologies perspective, the results show a very strong increase of offered capacities from wind and solar towards the daily procurement. Offered capacities from solar only appear with daily procurement. There are also seasonal effects, most pronounced for solar and onshore wind. Finally, there is also an impact of procurement cycle on the offered prices. As a consequence of the bidding strategy and necessity of having reduced capacity available for the DAM (in case of mFRR up), there is a difference in prices for upwards and downwards reserves. For mFRR down, only a strong difference in case of daily procurement can be observed, while for mFRR up, a shift towards cheaper prices and an increase in price diversity is observed. The obtained results motivate some future work to improve the simulation and gain additional insights.

ANALYSIS OF LONG-TERM INVESTMENT SIGNALS PROVIDED BY ANCILLARY SERVICES MARKETS

New system services, required for efficient operation of systems with high shares of variable renewable generation, will change the make up of future generation portfolios. Including these new system services within an investment model indicates a shift towards more flexible technologies. However, it is important that clear market signals exist for investors and conventional plant owners, in order to either commission new plant or retrofit existing generating units. Effective markets for new system services will create such signals, and will change the shape of long-term generation investments.

While unit commitment and economic dispatch models have evolved to capture variability and uncertainty impacts associated with high levels of variable renewable generation, traditional planning models typically do not incorporate sufficient temporal and operational detail to fully capture the real-time requirements for such systems. Consequently, the value of flexible technologies and energy limited resources is often not fully captured. A generic energy network optimisation tool, Backbone, is capable of performing both investment and operational optimisation, and enables analysis at sufficient temporal and operational detail, in order to capture the flexibility requirements of systems with high non-synchronous generation shares, while balancing model complexity against computational effort. A range of flexibility service requirements are explicitly modelled, including ramping products and fast frequency response, and the impact on investment decisions, and the operation of successful technologies, are explored for a system and a range of scenarios with associated technical scarcities. The analysis is completed for two core scenarios with varying degrees of variable RES generation, Steady Evolution and Low Carbon Living.

The results demonstrate how the inclusion of new (needed and valued) system services alter the optimum plant portfolio, and how new system services markets can send clear long-term signals to investors. In the absence of such markets, sub-optimal portfolios will be obtained, which can increase operating costs and CO2 emissions with increased renewable energy curtailment due to insufficient flexibility at certain times.

It is interesting to note that the additional reserve products have a much greater impact on the portfolios (and operating costs and emissions) in the Steady Evolution scenario over the Low Carbon Living scenario, which has much higher shares of variable renewable generation. When shares of renewable generation are sufficiently high, large investments in flexible technologies, such as batteries, are already justified, considering energy only markets, which indicates that incentivising suitable levels of flexible technology investments may be more crucial in the medium-term transition period in Ireland (~50% variable renewable generation), rather than for long-term, very high renewables scenarios. The largest changes to investment decisions for the Low Carbon Living scenario occur when a ramping product is included, as the product requirements are tied to wind levels. Greater investment in OCGTs occur, which have relatively low capital cost and can ramp from an off-line state, such that there is significant system value in procuring large reserve volumes from them, particularly if low plant utilisation.

For future (high renewables) systems, it is essential that adequate investment in flexible technologies are incentivised through strong investment signals via stable markets for the new system services. Marginal prices for both energy and system services are dependent on many factors, including fuel prices, interconnection capacity, installed capacity and capacity factors of variable renewables, and, indeed, competing sources of flexibility, all of which are associated with a high degree of uncertainty. While a fast product such as fast frequency reserve is of high value, the quantities required are small (compared to the energy market) and market saturation is a risk. Markets for such services require careful design, and relying on marginal cost pricing may not provide sufficient certainty for investors.

IMPACTS OF FLEXIBILITY AND UNIT COMMITMENT CHARACTERISTICS ON MARKET POWER EFFECTS

After the deregulation of the European electricity industry, electricity markets are characterised by imperfect competition, where players owning a large share of the market or located strategically in the network can behave strategically and manipulate the electricity prices in order to increase their profits. This market power exercise results in increased price levels and loss of social welfare. In this context, we need to move away from traditional centralized system operation models which have been assuming perfectly competitive behaviour, towards new models which can capture the strategic behaviour of multiple self-interested market players and identify likely market outcomes.

The existing literature on this area exhibits two limitations which are particularly important in the context of this project. First of all, the developed market models cannot investigate the impacts of flexible demand and energy storage as they are inherently unable to capture their time-coupling operating characteristics. This limitation is particularly important, given that the role of these flexible resources is extremely valuable for the cost-effective integration of renewable generation. Secondly, the developed market models cannot investigate the impact of the unit commitment (UC) characteristics of the producers on their strategic bidding decisions, as they are inherently unable to include binary UC decision variables in their representation of the market clearing process. This limitation is particularly important in the European market setting which moves towards complex bidding mechanisms.

Therefore, the objective of this particular topic lies in addressing these two limitations of the existing relevant literature through an advanced market model. This model adopts the basic methodological framework of the existing literature, namely bi-level optimisation founded on game-theoretic principles, since it captures the interaction between the strategic bidding decisions of self-interested players (modelled in the upper level) and the competitive clearing of the electricity market (modelled in the lower level). However, this model also captures the time-coupling operating characteristics of flexible demand and energy storage as well as the non-convex UC characteristics of the generation side. In order to address the fundamental mathematical challenge associated with these non-convex characteristics, our work employs a novel analytical approach recently proposed by the authors, which is based on the relaxation and primal-dual reformulation of the original, non-convex lower level problem and the penalization of the associated duality gap.

By employing this advanced model in a number of case studies, this work aims to address two research questions, which are relevant to the focus of this project: a) what is the impact of flexible demand and energy storage on market efficiency and b) what is the impact of considering the complex unit commitment characteristics on the strategic bidding decisions of electricity producers.

Regarding the first question, the results have demonstrated that the introduction of demand flexibility and energy storage drives a flattening effect on the price increments created by the exercise of market power: these increments are reduced at peak periods and are increased at off-peak periods. However, the former reduction is significantly higher than the latter increase, resulting in an overall reduction of market power and thus higher market efficiency. Regarding energy storage, this beneficial impact is reduced when large storage capacity is owned by individual market players, since these players can exercise market power through capacity withholding in order to maintain the market price differential between peak and off-peak periods at higher levels and make higher profits.

When the underlying network is congested, this impact is location-specific; introduction of demand flexibility and energy storage at a particular location deteriorates the market power potential of local producers and improves the market outcome for the local consumers. Overall, the impact of demand flexibility and energy storage on market efficiency is positive irrespectively of their location; however, this positive impact is higher when they are located in areas with more expensive generation and higher demand.

Regarding the second question, the results have demonstrated that the consideration of the complex unit commitment characteristics results in more profitable bidding decisions for strategic producers than state-of-the-art approaches which neglect them. Furthermore, producers can exercise market power and increase their profits by misreporting non-convex operating characteristics (such as the no-load cost examined in this work), a strategic potential that cannot be explored with state-of-the-art approaches and could be very interesting for both strategic players and market regulators.

1. INTRODUCTION TO TASK 3.4

1.1 CONTEXT

With the advent of very high levels of variable renewable generation, as well as a move to more decentralised and distributed power electronic interfaced technologies, there are likely to be significant challenges that need to be overcome in relation to the technical, as well as the financial, characteristics of power systems. In the context of the EU-SysFlex project, high levels of renewable generation are defined as being installed capacities of renewables that succeed in meeting at least 50% of the total annual electricity demand. Transitioning from power systems which have traditionally been dominated by large controllable synchronous generation to systems with high levels of variable, limitedly predictable and non-synchronous renewable generation has been shown to result in technical as well as economic challenges for balancing and operating power systems safely and reliably.

Deliverable 2.1 of the EU-SysFlex project has performed a comprehensive review of the literature and identified a number of key technical scarcities associated with integration of variable, limitedly predictable and non-synchronous generation and the associated displacement of conventional synchronous generation. These scarcities, if not mitigated, may impact the security and stability of the power system of the future.

1. The advent of non-synchronous renewable generation will result in a need for extra system services, such as operating reserve capabilities, to ensure there will be sufficient frequency control capabilities across multiple time frames
2. The displacement of conventional technologies means that the typical suppliers of these system services will decrease. This poses challenges related to system stability, reactive power control, system restoration capabilities (e.g., black start services) and system adequacy. It further implies the need to open system service supply to, and develop related provision capabilities for, non-conventional technologies.
3. The transition to power systems with high levels of renewable generation results in high levels of variable generation, both at the transmission level, but also embedded in distribution networks. The variability and limitedly predictability of renewable generation can be partially mitigated by geographical smoothing. In this regard, transmission and distribution networks are considered to be key providers of flexibility. However, with increased renewable generation, this can also lead to increased congestions, both at transmission and at distribution level.

In recent times, there have been many changes to system services. These adaptations have mainly been driven by new service providers, new entrants to the market and the drive towards greater cross-border coordination, rather than being driven by the evolving needs of a future power system with very high levels of variable renewable generation. In order to mitigate the technical scarcities that were identified and studied in WP2, and to continue to provide a secure and resilient power system for consumers, new and innovative system services may be required, to complement the existing suite of ancillary services. In addition, new service providers will need to have a route to market, and novel remuneration mechanisms and innovative market designs need to be explored.

1.2 WP3 OBJECTIVES

Developing and analysing the innovative product and market designs and regulatory options that can address the challenges outlined above is the focus of Work Package 3: "*Analysis of market design and regulatory options for innovative system services*" in the EU-SysFlex project. WP3's main objectives are:

1) A conceptual analysis to determine a comprehensive "basket of products" with detailed characteristics to fulfil the need for system services;
2) An extensive analysis of role models, possible market organization schemes and associated regulatory frameworks to identify barriers and solutions to overcome them;
3) An in-depth analysis through market modelling studies of key market/regulatory design parameters; and
4) A detailed business use case analysis for the demonstrated products to provide functional specifications to enable the innovative system services and facilitate the development of system use cases (in other WPs).

1.3 TASK 3.4 AND RELATIONSHIP WITH OTHER TASKS

Within WP3, the main objective of Task 3.4 was to complement the conceptual market designs of Task 3.2 through advanced power system and market modelling studies, considering both the long-term (investment) and short-term (operational) impacts of these designs on the pan-European power system. This interaction itself has to be seen in the wider context of WP3 and the EU-SysFlex project as a whole, as presented in Figure 1-1.

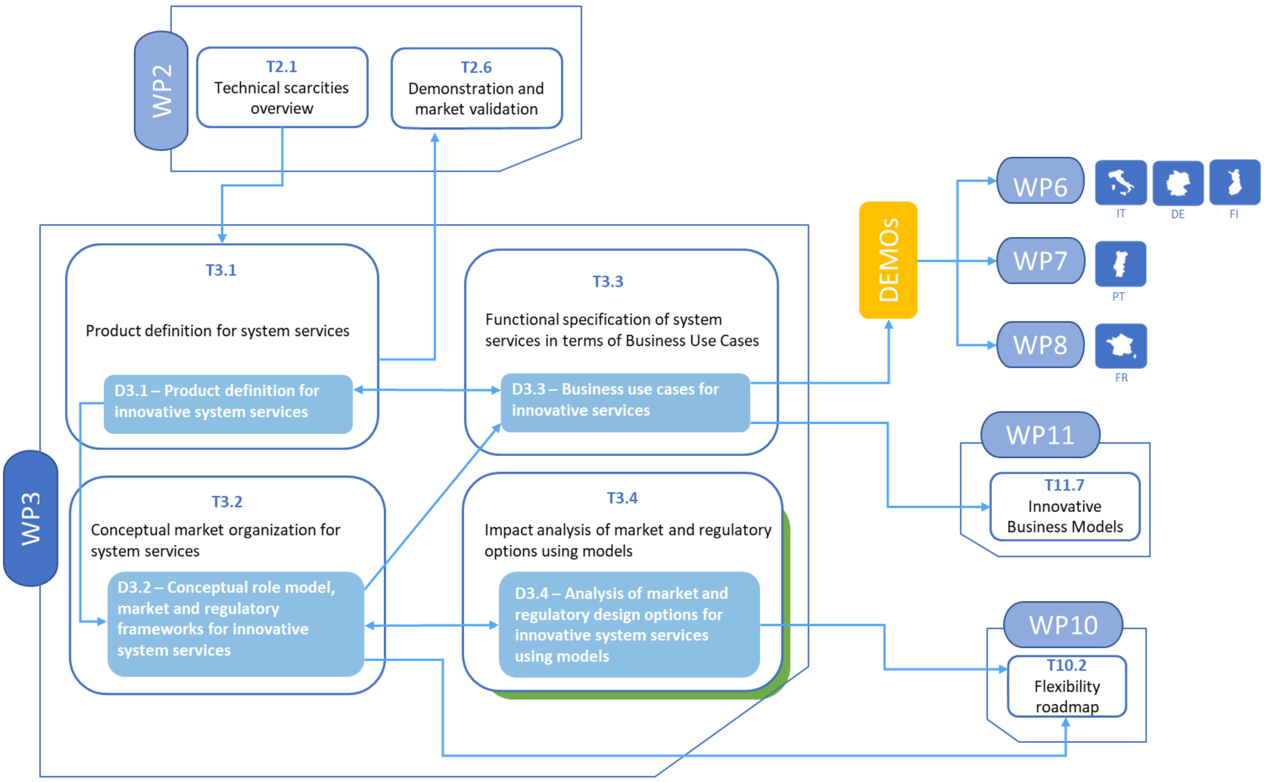


FIGURE 1-1: TASK 3.4 IN THE WIDER CONTEXT OF WP3 AND THE EU-SYSFLEX PROJECT

Task 3.4's main focus was on the operational timeframe – seconds, minutes, hours – analysing how different market and product designs of systems services play out in different power system configurations: distribution vs. transmission level, isolated vs. interconnected, lightly-loaded vs. congested grids, etc. A range of advanced models were deployed to study these effects, ranging from flexible UC/ED models (stochastic/deterministic, adaptive in terms of considered technologies, interconnections, geographical and temporal scope, etc.) over game theoretic approaches (equilibrium models, bi-level optimization, etc.), agent-based simulations to investment models.

Task 3.4's main interaction with Task 3.2 are the key market design/regulatory options proposed for analysis, and feedback of model results to support the argumentation on these different options. Task 3.2 as a whole focused on the organization of markets and regulation to facilitate the innovative system services, looking at role models and interactions in the provision of system services, and benchmarking market designs and regulatory frameworks to identify issues and barriers, as well as ways to overcome them.

Finally, Task 3.4 interacts with WP10 and, indirectly, with the demonstrators (WP6-9). The scientific evidence for market design options developed within this task will feed in the flexibility roadmap of WP10. Moreover, through the support of the work in Task 3.2, the task contributes to the development of market/regulatory options to procure, activate/operate, measure and settle the defined innovative products for system services in a cost-efficient way.

1.4 REPORT OUTLINE

The remainder of this report is outlined as follows. Chapter 2 provides an overview of the approach that was used in this task, notably highlighting its interaction with Task 3.2. Chapters 3-11 then present the research that was performed under Task 3.4 on market/regulatory design options:

- **Chapter 3**: Enhancing TSO-DSO integration to facilitate market access for distributed energy resources
- **Chapter 4**: Interdependence of energy and reserve markets in high-RES systems
- **Chapter 5**: On the temporal granularity of joint energy-reserve markets in a high-RES systems
- **Chapter 6**: Benefits of regional coordination of balancing capacity markets in future European power markets
- **Chapter 7**: Pre-selection of the optimal siting of phase-shifting transformers based on an optimization problem solved within a coordinated cross-border congestion management process
- **Chapter 8**: Defining the TSO's investment shares for PSTs used for coordinated redispatch
- **Chapter 9**: Increasing technology neutrality in service markets in power systems with high RES shares
- **Chapter 10**: Analysis of long-term investment signals provided by ancillary services markets
- **Chapter 11**: Impacts of flexibility and unit commitment characteristics on market power effects

2. METHODOLOGY AND APPROACH

2.1 OVERVIEW

Within Task 3.4, several regulatory, product and market design options were studied. A key emphasis was to benchmark these options, partly provided by Task 3.2, with ideal, fully integrated market/regulatory settings. Moreover, these options were evaluated in advanced models with detailed representations of the short-term operational constraints of power systems, capturing both power system reliability and the impact of such constraints on market designs and outcomes. The results of these research topics, in turn, provided scientific ground for the regulatory, and product and market design options of Task 3.2 (outlined in Section 2.2).

Surveying the work performed under Task 3.4, the following areas of research have been explored, all of which provide further insight into how the different options would perform in practice:

- **Market and regulatory design**
  a) Integrated markets (simultaneous clearing) versus sequential clearing
  b) Bias respectively neutrality in the ability for (new) technologies to participate
  c) Clearing frequency, temporal resolution and lead time for system services
  Related work: Chapter 4, Chapter 5, Chapter 6, Chapter 9
- **Market behaviour**
  a) Market participant decision making in multi-service markets
  b) Potential for strategic behaviour in system service provision
  Related work: Chapter 9, Chapter 11
- **Geographical aspects**
  a) Locality of system services, i.e., coordination of TSOs and DSOs
  b) Interconnections and cross-border exchange of flexibility products
  c) Cross-border coordination and congestion management
  Related work: Chapter 3, Chapter 6, Chapter 7
- **Investment effects**
  a) Long-term investment signals of short-term system services
  b) Cost/benefit analysis of cross-border coordination and investment allocation
  Related work: Chapter 8, Chapter 10

The different chapters explore separate research question in high detail, using advanced modelling techniques on power system operation and market clearing, to contribute to the overall research aims of Task 3.4:

- **Chapter 3** studies TSO-DSO coordination for the optimization and control of the use of distributed energy resources. It uses detailed market and network models to study the performance of a Virtual Power Plant coordination approach in a centralized and decentralized context. This provides insights into the trade-off between optimality and complexity of the market and control mechanisms, and into the role of DSOs in enabling the use of distributed resources.

- **Chapter 4** studies the interdependence of energy and reserve markets by exploring sequential and joint market designs. It does so by employing a highly detailed unit commitment and economic dispatch model. This model includes detailed constraints related to power system technologies' technical abilities, e.g., on ramping, minimum operating points, and start-up and shut-down limitations. This provides valuable insights into the trade-off between a more complex market clearing algorithm, combining energy and reserve, and the operational and economic benefits this would unlock.
- **Chapter 5**, building on a similar methodology (including a detailed UC/ED model), explores the temporal granularity of four different dimensions of reserve products: the sizing frequency and resolution, and the procurement frequency and contract duration. This provides insights into the trade-off of developing more complex product and market designs and the potential welfare benefits that this can lead to.
- **Chapter 6**, also building on a similar methodology with a UC/ED model, explores different configurations of cross-border coordination in ancillary services markets in line with recent publications from the European Commission and ENTSO-E. Here, insight is created on the one hand into the trade-off between more complex cross-border market coordination and an increase in social welfare, and on the other hand into the reduction of security margins (through joint reserve sizing) and an increase in social welfare.
- **Chapter 7** and closely related **Chapter 8** explore cross-border management of congestion, through redispatch opportunities and investment opportunities, with the associated analysis into activation cost settlements and investment cost sharing. In both chapters, detailed network models are employed to ensure proposed solutions are operationally sound. Both chapters provide key insights into the mechanisms and benefits of coordinated network management and investment in network assets including phase-shifting transformers.
- **Chapter 9** investigates the impact of changing the parameters of ancillary services market design with regard to the participation of RES, focussing on the procurement cycle of mFRR and participation of wind and solar. As such, the employed agent-based market modelling allows to study the technology neutrality of market designs. Results provide insight into the extent to which market designs allows to fully translate the technical potential into market value.
- **Chapter 10** explores the impact ancillary service markets have on long term investments. It employs an investment model with a high level of operational detail to examine changes in investment decisions in the presence/absence of requirements for different ancillary services. It provides insights into the magnitude of the investment signals driven by ancillary services markets and the timeframes over which they matter most.
- **Chapter 11**, finally, studies how market power is affected by flexibility and operational constraints. It employs game-theoretic, strategic market modelling. It provides insights into the impact of flexible demand and energy storage on market efficiency, important flexible resources for the cost-effective integration of renewable generation. It provides further insight into the impact of complex unit commitment characteristics on the strategic bidding decisions of electricity producers, important in a European market setting that is moving towards complex bidding mechanisms.

2.2 INTERACTION WITH TASK 3.2

As discussed in Section 1.3, Task 3.2 is concerned with the conceptual market organisations for the provision of innovative system services. It describes and frames the responsibilities for power system operation (regulated) and the responsibilities of, and interactions with deregulated players (in particular flexibility service providers, e.g. aggregators), in light of system service delivery (frequency control products, congestion management products, voltage control products or inertia) by both centralized and decentralized energy resources (demand response, storage, generation). It analyses electricity and system service market/regulatory aspects with specific attention for market harmonisation, ENTSO-E grid codes, benchmarking proposed role models and organisations with existing market designs and regulation in EU countries.

Over the course of the analyses carried out under Task 3.2, several key attention points in the market/regulatory options were identified that motivated further analysis with advanced models under Task 3.4. The following questions, among others, were examined in Task 3.2 and link to the research in Task 3.4 as such:

1) What parameters are important when designing products and market characteristics?
    a. **Chapter 5** provides key insights into the procurement organisation of generic flexibility services. Specifically, it explores several dimensions of product design, how they related to the cost-efficiency of system service provision, and how they enable/prevent the participation of different types of providers. In that regard, additional insights in how to design technology-neutral markets are generated in the research in **Chapter 9**.
    b. **Chapter 9**, also, using an agent-based market simulation, focusses on the first two of the four market phases proposed in Task 3.2: pre-qualification, procurement, activation and settlement. The market participants and market operators in the model are equivalent to the flexibility service providers and optimization operators, respectively, in the role models from Task 3.2. The model is then applied to a specific case study, results of which provided support for further market design work in Task 3.2.
2) What are the advantages and drawbacks of a regulated organisation vs. a market-based organisation?
    a. **Chapter 10**, through its exploration of the long-term investment signals of system service markets, offers key insights for the design of these markets. The warnings on market saturation and possible volatility of system service markets – unwelcome factors for many investors – push thinking on market design to find opportunities on revenue stacking (e.g., different system services) and other regulatory interventions that can create more stable investment conditions.
    b. **Chapter 11** explores market power effects. Its results provide important insights into the role of flexibility providers (demand response, storage) and the impact of technical constraints on the potential for strategic behaviour. As such, it provided valuable input for further market/regulatory design to pay attention to new types of market behaviour that could be challenging to monitor/regulate.

3) How can cross-border flexibility procurement best be organized?
    a. **Chapter 6** explicitly studies the allocation of cross-border interconnection capacity for energy and reserves. A market formulation is developed that includes the clearing of both types of markets and cross-border capacity constraints. This provides insights into the importance of these grid constraints and the use of this capacity in highly renewable systems, helping to navigate the trade-off between complexity of market clearing models and, for example, price traceability.
    b. **Chapter 7** and **Chapter 8** go into even more detail in network representation and analysis, studying coordinated cross-border congestion management processes. The work in these chapters helps gain insight into the cost/benefit-distribution effects of different flexibility procurement strategies in addition to a detailed analysis of the impact of grid constraints on that procurement.
4) What coordination between TSO and DSO is required?
    a. **Chapter** 3 analyses coordination strategies for the use of distributed energy resources. It looks at the use of smart controls for the minimization of system cost and the enhancement of control coordination between TSOs and DSOs. It compares the performance of priority use of those distributed resources for DSOs with a co-optimized TSO-DSO use and how those modes of coordination impact power system performance aspects.
5) Is a joint procurement of some flexibility services possible, in particular for frequency control products and congestion management?
    a. **Chapter 4** explores the potential for joint organisation of markets, in its case energy and frequency control products. It provides insight into the way energy and flexibility bids are linked in practice, and should in a market design preferably be as well, in order to capture operational constraints. It further provides reflections on weighing the resulting market design complexity with the potential gains of such a joint procurement approach.
    b. **Chapter 6** implicitly captures the joint procurement of frequency control products and congestion management by studying the effect of incorporating cross-border interconnection constraints in a joint energy and reserve market clearing set-up. This provides insight into the benefits of an endogenous optimization of the allocation of transmission capacity, in this case interconnection capacity between multiple market zones.

In addition to these specific inputs, the work under Task 3.4 provides several key messages across the different chapters that support the outcomes and recommendations of Task 3.2.

- ✓ The work shows that improvements in market design can facilitate the sustainability transition.
- ✓ The work provides evidence of specific ways that regulation and market design can do so. The implementation of shorter-term, higher resolution ancillary service markets reduces the cost of ensuring system reliability, among other things by enabling the participation of nonconventional providers such as demand response and variables renewables. Cross-border coordination in both markets and system

management (e.g., cross-border congestion management) also reduces the cost of ensuring system reliability.

- ✓ The work calls attention to key challenges for regulation and market design. New market power effects associated with new service providers and technical constraints need to be understood in more detail. System service markets have to provide sufficiently stable investment signals such that the required flexibility will be developed.
- ✓ All chapters indicate that these effects become increasingly significant as renewable shares grow, and therefore point to the importance of action being taken sooner rather than later.

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The content chapters of the deliverable D3.4 are still confidential due to pending publication processes in peer-reviewed journals.

You can contact the authors to get access to the specific chapters

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