New market designs in electricity market simulation models

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1.0	31.08.2021	Public	The new market designs and their implementations in the market models in subtask 4.2.2 will be featured in this report.

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Executive Summary

To integrate a high share of renewables in a future system, several modifications to the electricity market rules may need to be implemented. The most relevant market design concepts were identified from the literature and reported in work package 3. There are several uncertainties, for instance with respect to the questions of whether a future electricity market will provide enough incentives for investment in variable renewable energy sources (vRES) – mainly solar and wind energy – and in flexibility options, especially for long periods with insufficient vRES generation. In this deliverable, the modelling requirements to analyse the new market rules are determined. The modelling efforts will reflect the main policy choices and are based on the strengths of the modelling capabilities from the consortium.

The model enhancements to represent the temporal, spatial and sectoral flexibility will be approached in deliverables 4.1 to 4.3. For this reason, these topics will be described only briefly in this deliverable.

The first three chapters after the introduction describe the market design choices at the wholesale and retail levels that will be modelled. The primary objectives for changes to these markets are to allow trade closer to real time, in order to reduce the imbalances from vRES, and to stimulate flexibility options at all system levels, in order to absorb the fluctuations in the output of vRES. The consortium's agent-based models will be used to simulate the impacts of market improvements such as a higher time resolution in the wholesale market, shorter lead times for trade, the exposure of the demand side to real-time prices and the impacts of levies and subsidies.

Transmission and distribution network regulation play a role in the integration of vRES, but they will play only a peripheral role in our analysis. The reason is that the challenges with electricity network tariff regulation and congestion management are on the one hand not particular to vRES integration and thus not within the narrower scope of TradeRES, while on the other hand they have been a topic of study since the liberalization of electricity markets. Therefore, the network congestion will be considered, as it may affect vRES integration, and where necessary we will factor in the impact of network tariffs, but TradeRES will not research new congestion management methods or tariff schemes. The transmission network will be modelled with single nodes per bidding zone, considering the physical constraints of cross border capacity. Dynamic line rating as a means for increasing useable interconnector capacity is investigated.

The way in which ancillary services are procured affects the costs and benefits of vRES. The analysis in TradeRES focuses on the following design variables: the symmetry of bids (upward and downward capacity), gate closure times, the market time unit, payment schemes and the minimum bid size.

The second part of this report, from Chapter 6 onwards, describes several policies that may be implemented to improve future electricity markets. One of the main objectives of TradeRES is to evaluate under which conditions a future electricity market – with a very high penetration of renewables – will provide system adequacy and an efficient dispatch. To simulate a future power system, the consortium members contribute two types of models, agent-based models and optimization models. The evaluation of system adequacy in

Chapter 6, begins with a base scenario that represents an energy only market. In addition, a selection of capacity mechanisms will be modelled to investigate the extent to which they improve the performance of the market with respect to system adequacy, investment risk and cost and risk to consumers.

Chapter 7 presents the modelling choices for sector coupling. This may have a significant impact on system adequacy, as it influences not only overall electricity demand but also the volume and nature of flexibility options.

The last two content chapters, Chapters 8 and 9, describe the modelling of the two main policy instruments for decarbonizing the electricity system, the European Emissions Trading System as a means of carbon pricing and RES support schemes. In the base case analyses, it will be assumed that no CO_2 may be emitted, so there also will not be a CO_2 market, and it will be investigated whether an energy-only market will provide sufficient incentives for investment in vRES. However, as in case of system adequacy, we will investigate vRES support instruments in case there is a possibility that they will continue to be needed in the long term. We will also include a representation of the CO_2 Emissions Trading System in our analysis in order to be able to simulate transition steps between the current situation and a zero-carbon system. For this purpose, this deliverable includes the description of how the Emissions Trading System can be modelled in the model EMLab, along with the Market Stability Reserve and price floors and caps. Similarly, vRES support schemes – such as feed in premium, market premium, capacity-based support and contract for differences – will be modelled.

The model enhancements are currently under development. This deliverable contains the advancements until August 2021. In the second iteration of this report, major modelling activities, which are planned for the next months and years, will be reported.

Table of Contents

List of Tables

List of Figures

List of Abbreviations

aFRR *automatic frequency restoration reserve*
BRP *balancing responsible party*
CFD *contract for differences*
DER *distributed energy resources*
DyLR *dynamic line rating*
DSO *distribution system operator*
EOM *energy-only-market*
ETS *Emission Trading System*
ICAP *Installed Capacity*
ISO *Independent System Operator*
LCOE *levelized cost of electricity*
LSE *load serving entity*
mFRR manual frequency restoration reserve
MIBEL *the Iberian electricity market*
OHL *overhead line*
PFS *Power Flow Service*
SLR *static line rating*
VAT *value-added tax*
VOLL *value of lost load*

1 Introduction

This deliverable implements Subtask 4.2.2: “Representation of (new) market designs”, which is described as follows in the project proposal:

To enable the assessment of the performance of market design options as well as the time- and location-specific value of new market products, corresponding market and price-forming structures will be implemented into the market models in this subtask. This includes, e.g., new remuneration mechanisms for ancillary services and generation capacity (see Tasks 3.3 & 3.5) as well as consumer-side incentives. The actual performance analysis of these market designs will be executed in WP5.

This deliverable therefore describes the way in which various aspects of market design are implemented in the models of TradeRES. The focus is on modifications to the short-term market design that will enable a more flexible system that can influence the required installed capacity. With respect to temporal flexibility, Chapter 2 describes the requirements to model changes to the wholesale market design. In Chapter 3, the design of ancillary service provision is described. Next, Chapters 4 describes the same for the retail/distribution network level. Chapter 5 describes how transmission tariffs and congestion will be represented. Chapter 6 discussed the key issue of system adequacy, while Chapter 7 describes the representation of sector coupling, an important feature of the future energy system. The final chapters, 8 and 9, present how two important policy instruments, CO_2 policy and RES support, are modelled. Final remarks are given in Chapter 10. This deliverable is accompanied by a series of other deliverables from TradeRES Work Package 4 “Development of Open-access Market Simulation Models and Tools”. All of these deliverables are to be published within a timeframe of a few months. Please refer to these deliverables to gain deeper insights on their specific topics:

- Deliverable 4.1 covers model enhancements with respect to temporal flexibility.
- Deliverable 4.2 focusses on the implementation of sectoral flexibility within TradeRES models.
- Deliverable 4.3 describes spatial flexibility options and their implementation in TradeRES models.
- Deliverable 4.4 looks at new actor types in electricity market simulation models, starting with the given agent configurations of the ABMs.

2 Wholesale market design

Long-term bilateral agreements and day-ahead markets were designed for conventional dispatchable power plants, since the power forecast of variable renewable energy sources (vRES) and demand have significant errors for time horizons greater than six hours [1]. With the introduction of large amounts of vRES, wholesale markets need to provide more flexibility to compensate imbalances. This can be achieved by allowing trade to take place closer to real-time (delivery time). Furthermore, allowing bids of aggregated or hybrid vRES, making vRES (partially) dispatchable, can also reduce forecast errors and therefore balancing needs. A major objective of the modelling efforts will therefore be to investigate if such modifications to the wholesale market can reduce imbalances. A second objective of modelling wholesale markets is to assess generators' revenues. We want to analyse for both, vRES and dispatchable generators, how well they can be expected to recover their costs in a low-carbon energy-only market.

This section contains the high-level requirements for modelling these changes to market design. A more detailed description of the implementation of flexibility options will be presented in D4.1, D4.2 and D4.3.

2.1 Shorter lead time between market closure and delivery time

Shorter lead times, between market closure of day-ahead or intra-day markets and delivery can reduce forecast errors, especially from vRES, and demand. Thus, bringing market closure closer to real time can reduce balancing needs and also facilitate providers of vRES. The current standard design of day-ahead wholesale markets in Europe entails a market closure time at noon for trade for the 24 hours of the next day. A simple - albeit important - option is to **shift the market closure time to a moment later in the day**. However, if all hours of the following day are traded at once, this still implies that the forecast errors will increase over the 24 hours of the traded period and that logically, the latter hours would be traded more than 24 hours before delivery. The current intraday auctions design also bring along the same drawback in terms of forecast errors, since clearing all 96 quarter-hours of the following day is carried out here. In some countries, however, the auctions are held closer to delivery time (3 pm of the previous day for AT, BE, D and NL), though. Nonetheless, retaining some lead times and having a first (indicative) scheduling procedure enables the transmission system operators (TSOs) as system operators to retain a stable system.

As of now, a multi-stage decision making is used to tackle these issues. Continuous intraday trading provides market actors with the opportunity to improve their forecasts and trade until delivery time. Nonetheless, since improved information is available to all market participants in the intraday timescale and due to structural deviations between current day-ahead and intraday markets design (e.g., trading hours vs. quarter-hours), outcomes may not be most efficient, and one might rethink the day-ahead market design and its relation with intraday markets. Since the models used in TradeRES – except for MASCEM – do not contain an intraday market representation, we focus on changing day-ahead market designs and a single auction-based market clearing as well as on the general trends we can observe with bringing gate closure closer to delivery.

A second option we analyse is to trade electricity in rolling auctions, i.e. that every hour the market is closed for delivery a fixed number of hours in the future, e.g. six hours before delivery time. This would make it possible to reduce the forecast errors further and would eliminate the issue that the forecast error would increase over the 24-hour period. However, it would require not only the intra-day traders but also the wholesale traders to be active around the clock, rather than submitting their bids once per day.

The implementation of shorter lead times (e.g. for the agent-based dispatch model AMIRIS) is described in D4.1. The implementation of a rolling time-horizon market clearing process, in which the market is cleared per time unit, a fixed amount of time before real time, will be tested within TradeRES project to assess the potential benefits in different case studies. Similarly, to shorter lead times, a rolling-time market clearing procedure instead of clearing all hours of the day-ahead market simultaneously could also improve the quality of information of traders. In AMIRIS and RESTrade models, it is possible to simulate hourly or even more frequent clearing. In MASCEM, it is possible to clear the market at any specified time interval; usually in periods of one hour, half-hour, 15 minutes or 5 minutes; but not excluding any other periodicity that may be defined. MASCEM market models can also be executed for any horizon before delivery, usually day-ahead, hour-ahead, 15 and 5 minutes-ahead, but any other horizons can be simulated. See D4.1 for a detailed description of the flexibility options that AMIRIS, MASCEM and RESTrade can or will simulate. Besides the shorter lead time and the rolling time horizon, some of these models will (or already do) represent load shedding, load shifting, electricity storage and real time pricing.

Contribution to the electricity market models under development in TradeRES: provides insight in the benefits of wholesale market reforms for vRES integration

Input data: weather and demand forecasts and realizations, electricity supply data

Output data: wholesale market clearing prices and balancing market results; The hypothesis is that the balancing volumes and prices decline with shorter lead times.

2.2 Shorter time units

Trading shorter time units facilitates actors who may only offer capacities within a limited time window. Examples are industrial demand response and energy storage units with a high power to stored energy ratio. Instead of the current hourly resolution of wholesale markets, wholesale trade could be conducted in blocks of 30, 15 or even 5 minutes. Shorter time units could also help facilities that have significant ramping constraints. Currently, the main ones are thermal power plants, but the flexibility of large industrial processes may also be constrained by ramp rates and the same may be true of the electrolysers for hydrogen production in the future. In AMIRIS, the choice of product duration is flexible. Similarly, shorter trade time units are modelled in MASCEM and RESTrade (see D4.1).

Short-term intraday markets can be used to cover some of the deviations of market players, but they have limited liquidity. Several studies indicate that reducing the time unit of these markets to at least 15 minutes can substantially reduce the need for balancing reserve [2].

Contribution to the electricity market models under development in TradeRES: provides insight in the benefits of shorter trade time units for vRES integration

Input data: power and demand forecasts and realizations, electricity supply data

Output data: wholesale market clearing prices and balancing market results; The hypothesis is that the balancing volumes and prices decline with shorter time units.

3 Ancillary services

Although vRES can cause more imbalances in the system and increase the ancillary services requirements, they can also provide some of these services [3] . In this section, new market designs for ancillary services, to be modelled within TradeRES and studied in the context of the Iberian market (MIBEL), are described.

TradeRES Deliverable 3.3 pointed out some of the major challenges of the ancillary services for power systems with high shares of vRES[1]. The problem starts with the long- to mid-term markets. Day-ahead markets close between 13 to 37 hours before delivery, when vRES and demand-side players have to bid based on forecasts with substantial errors.

Gate closures closer to real-time operation, shorter time units (to at least 15 minutes), and improvements in the dispatchability of vRES are aspects that bilateral and spot markets can adapt to reduce the balancing needs (see e.g. [1], [2], [4], [5]), Short-term markets as intraday markets are used to cover some of the short-run deviations of market players, but they have limited liquidity [4]. Furthermore, allowing bids of aggregated or hybrid vRES, making vRES (partially) dispatchable can also reduce their forecast errors and reduce the balancing needs.

- **Gate closure**

As in spot markets, one of the main issues that increases the volume of automatic frequency restoration reserve (aFRR) capacity inefficiently is its gate-closure horizon. A gate closure long before real time decreases the forecast accuracy highly when predicting the maximum expected consumption or net-load, which conducts to an unnecessary increase of the aFRR capacity size [1], [4].

- **Market time unit**

Another issue that increases the size of the aFRR capacity is its market time unit. This type of reserve was designed for a continuous use of 15 minutes (maximum), so it will be more efficient if the market time unit does not surpass this value [3].

Balancing products were designed for the participation of fast-responsive dispatchable power plants (e.g. hydro or gas plants that are capable of offering guarantee of power). Since vRES usually increase balancing needs, the design of markets should also enable and favour their effective participation in the trading process (within the range of their technical capabilities), to decrease the overall imbalances [4].

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[1] J. Sijm, A. van der Welle, G. Morales-España, and R. Hernandez-Serna, "D3.3 - Design of ancillary service markets and products: Challenges and recommendations for EU renewable power sys-tems," TradeRES project deliverable 3.3: p. 73, 2021. Available at: https://traderes.eu/wp-content/uploads/2021/07/D3.3_DesignAncillaryServiceMarketsProducts.pdf.

Against this background, a more efficient procurement of aFRR capacity will be tested in some studies involving (at least) the Iberian electricity market (MIBEL), by considering the vRES expected production, a separate procurement for upward and downward reserve, gate closures closer to real-time, and a shorter time unit.

- **Payment scheme**

Concerning the payment scheme of the aFRR capacity market, a pay-as-bid mechanism can reduce the aFRR costs while marginal pricing allows a non-discriminatory participation of all producers. The clearing of the market is exactly the same using both algorithms, the main difference is that while using marginal pricing all players receive the clearing price, using pay-as-bid they receive the price they bid. So, agents should adapt their behaviour considering the payment scheme of each market. Pay-as-bid does not incentivize vRES participation based on their marginal prices, which can lead to an inefficient use of the free-of-cost vRES production, leading to curtailments and to the need of RES support schemes to guarantee their economic viability. Preliminary results (to be confirmed within TradeRES) indicate that marginal pricing appears to be a more adequate mechanism to incentivize a non-discriminatory participation of all producers based on their marginal costs, as suggested by energy economics [6]. Otherwise, vRES may use strategic bidding that may not consider their optimal operation, reducing the general welfare of market participants.

Regarding aFRR energy markets, one of the main issues consists of the lack of competition in some countries. Another situation is that some electricity markets/control zones do not have an aFRR energy market, being the aFRR energy paid by the *manual frequency restoration reserve* (mFRR) energy price. This is not an efficient procedure since aFRR's participants may have different marginal costs when comparing with mFRR's participants. The TradeRES Project will address alternatives for the electricity markets that may benefit from them.

Against this background, the balancing markets should be coupled between different countries to increase competition and decrease the balancing needs. A good example of existing coupled balancing markets is the Nordpool [7].

- **Minimum bid size**

Another non-discriminatory change that can increase market participation and competition in the balancing markets with high amounts of vRES is the reduction of the minimum bid size to 0.1 MW and 0.1 MWh to capacity and energy markets, respectively. This change incentivizes the participation of demand-side players, medium-scale vRES, and hybrid power plants ([2] .

- **Procurement of aFRR capacity**

ENTSO-E suggested a symmetrical procurement of aFRRs capacity based on the maximum expected consumption ([8], [9] . The use of symmetrical procurement for upward and downward capacity of aFRR increases operational costs and reduces efficiency. Some European countries updated this methodology by considering also the expected vRES production, decreasing the size of the required capacity, e.g. as in MIBEL [10]. Indeed, in power systems with increasing levels of vRES, using the maximum absolute value of the expected net load should be a better procedure than considering the maximum consumption. Some countries do not also use a symmetrical procurement of upward and downward capacity, changing their size to increase efficiency [10]. As this separate procurement for upward and downward capacity could be more efficient, TradeRES will address this aspect and analyse the impact of trading vRES in markets with high shares of renewables. A study involving (at least) MIBEL is foreseen at this phase of the project.

Most aFRR and mFRR energy markets already have a separate procurement for upward and downward energy. So, to increase the efficiency of these markets, closer to real-time gate closures are considered such as shorter time units [2]. The mFRR energy market is more attractive than spot markets [4]. Therefore, the costs to have mFRR capacity markets can be suppressed [4]. Table 1 presents the modelling approaches employed to upgrade the ancillary services considering future power systems with near 100% RES penetration addressed by RESTrade.

Table 1: Modelling approaches considered for ancillary services

Mechanism	aFRR capacity	aFRR energy	mFRR energy
Procurement	Separated upward and downward capacity based on expected maximum consumption, and vRES production	Separated upward and downward energy based on 5–15 minutes dispatch to cover frequency deviations	Separated upward and downward energy based on 15–60 minutes dispatch to cover frequency deviations
Payment scheme	Pay-as-bid / Marginal pricing	Marginal pricing / Pay-as-bid	Marginal pricing / Pay-as-bid
Trading procedure	Direct / Auction	Auction / Direct	Auction / Direct
Gate closure	2 hours-ahead	25 minutes-ahead	25 minutes-ahead
Time unit	5–15 minutes	5–15 minutes	15–30 minutes
Minimum bid size	0.1 MW	0.1 MWh	0.1 MWh

The TSO agent will be equipped with the modules containing the algorithms of each aFRR and mFRR balancing markets. The technical activation of these mechanisms has been studied in Deliverable 3.3 of this project. The representation of these markets will be harmonized to the whole Europe, so, they can be used in all case studies. Furthermore, TSOs will also be equipped with a harmonized imbalance settlement module, responsible to compute the penalties. This module is crucial due to the real-time unbalances that balancing responsible parties (BRPs) must pay in case of deviations, which derives from the system costs with balancing markets.

Contribution for the electricity models under development in TradeRES: Provides the need for secondary (aFRR) and tertiary (mFRR) control such as the prices of their markets and their participants' dispatch. Also provides the penalties due to each BRP deviations from schedules.

Input data: Receives all programmed dispatch of all market players, considering the previous markets' results. The aFRR capacity market receives a forecast of the maximum expected consumption and vRES production. During real-time operation TSOs receive the instantaneous produced and consumed power, using the balancing reserves to balance these powers in case of frequency deviations. TSOs also receive the market participants bids to these balancing markets.

Output data: TSOs should provide the aFRR capacity needs, each agent programmed dispatch in case of participating in the balancing markets, and each market prices, capacity reserved and energy used in every balancing direction for the defined time-units (see Table 1). Furthermore, the penalties paid by BRPs due to their deviations will also be provided.

4 Retail market design

Complementary to wholesale markets, retail markets also facilitate the active participation of demand in the market. While conventional electricity demand showed to be relatively inflexible in the past, new types of consumption such as the charging of electric vehicles and electric heating may be much more flexible, which facilitates their integration despite the large increase in demand that they cause. In order not to additionally burden consumers, their flexibility should only be called upon when it benefits the energy system. If flexible consumption can reduce network peaks and/or improve the utilization of vRES, this may reduce system cost. Consumers are exposed to a combination of financial incentives:

- **The price of electricity**. As mentioned in D3.5[2], in TradeRES we assume that in the future, this will be based on the wholesale price for electricity.
- **Renewable energy support schemes**, e.g. feed-in tariffs for vRES systems (if they exist for small prosumers).
- **Taxes, levies and subsidies** such as value-added tax (VAT) and renewable energy levies.
- **Network tariffs**. Network tariffs usually reflect consumers' variable costs for annual consumption and sometimes also a fixed component reflecting peak consumption. Yet, they typically do not reflect the real-time costs of network usage due to congestion, for instance. Proposals exist to make them flexible as a way to reduce congestion.
- **Potential payments from network congestion management**. If the network tariffs do not provide (sufficient) incentives to avoid congestion, additional instruments[3] can be implemented to handle it.

Renewable energy support schemes are discussed in Section 9 of this deliverable. The latter two topics, network tariffs and congestion management, will be discussed in Section 5.1. This section will therefore focus on the modelling of retail price of electricity and taxes and levies in markets with high shares of vRES. In addition, in Sections 4.3 and 4.4 we will present two particular aspects of retail markets that influence their performance in a renewable system, namely the roles of aggregators and of prosumers.

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[2] de Vries, L., Sanchez, I., Morales-España, G., et al.. "D3.5 - Market design for a reliable ~ 100 % renewable electricity system," TradeRES project deliverable 3.5: p. 62, 2021. Available at: https://traderes.eu/wp-content/uploads/2021/04/D3.5_MarketDesignOptions_H2020.pdf (accessed on 15.07.2021).

[3] These instruments may take the form of congestion pricing or of fixed payments/tariff reductions to consumers for being flexible. Congestion does not need to be managed with financial incentives, however, but may also be handled through technical control options whose costs are socialized over all consumers.

4.1 The electricity price

Real-time pricing of electricity is the most accurate reflection of the momentary marginal cost or value of electricity generation to society and therefore in theory the best signal for indicating the need for flexibility. The market price coordinates the dispatch of flexible generation units, storage and demand response by signalling at every moment the value of generation and/or social cost of demand reduction. Therefore, real-time pricing will be included in the models of TradeRES. Usually, real-time pricing is understood as passing the wholesale price of electricity, i.e. the day-ahead market price, on to small consumers. This is how it will be represented in TradeRES, e.g. in the AMIRIS model (see D4.1). Consumers may also be stimulated to participate in balancing markets; the options for this will be presented in Section 3. A point of attention in our analyses will be how much risk this confers to consumers.

Contribution to the electricity market models under development in TradeRES: provides insight in the benefits of real-time pricing for vRES integration and the activation of demand-side flexibility resources

Input data: wholesale prices, demand response data (volumes, capacity, price response, maximum time that load can be shifted, etc.)

Output data: volume and capacity of load that is shifted, impact on system adequacy

4.2 Taxes and levies

Taxes such as VAT and levies such as for recovering the cost of renewable support are common and may have a significant impact on the cost of electricity to consumers, which are particularly relevant when considering incentivizing demand response and sector coupling. They will therefore be included in the models that analyse the impact of prices on consumers. Taxes and levies can be implemented in multiple ways. VAT is implemented as a fixed cost per unit of electricity consumption, as are most other taxes and levies. Therefore, we will include this option as well. In principle, energy taxes could also be charged as fixed annual payments, but this would be regressive with respect to income. Moreover, a common policy objective is to stimulate energy conservation and then a fixed rate tends to be ineffective, as opposed to a per-unit rate. Therefore, we do not include this option.

A per-unit tax rate distorts the market, on the other hand, as the consumption price of electricity no longer reflects marginal cost. This may become an obstacle to efficient charging of batteries, whether stand-alone or of electric vehicles. A third option is therefore to define the tax or levy as a percentage of the market price, i.e. a percentage markup [11]. While this still distorts the market price, it has as an advantage that surpluses of renewable energy lead to lower prices and shortages to higher prices and therefore may incentives consumer flexibility better.

Summarizing, the taxes and levies will be implemented in TradeRES models as follows:

- As a fixed rate per kWh of electricity consumption;
- As a percentage rate per kWh of electricity consumption.

AMIRIS already contains the option to pass volumetric taxes, levies and subsidies to prosumers (see D4.1).

Contribution to the electricity market models under development in TradeRES: provides insight in the effects of charges on top of the electricity price on prosumer behaviour

Input data: the price and structure of consumer taxes and levies on electricity

Output data: changes to prosumer behaviour with respect to the base case as described in Section 4.1

4.3 Aggregation

Aggregation of distributed energy resources (DERs) has been among the very promising operations foreseen in the zero-carbon paradigm as it enables the exploitation of the full potential of those small and medium-sized resources connected at the distribution level.

In D3.2[4], a separate aggregation layer was considered in the analysis of the actors' scene, with business entities such as suppliers, aggregators and VPPs engaging in aggregation activities. Based on the adopted classification, the suppliers are entities that buy electricity from the wholesale market or directly from the producers and sell it to the end users, while aggregators are entities that aggregate a number of end-users that own resources, like prosumers, producers or a mix of them, and engage as a single entity in markets.

Although margins in the supply segment are considered relatively low due to high competition intensity, the buy-sell spread that is incorporated in the static or dynamic version of tariffs, which may even take the form of real time pricing, represents the costs of the offered retail services. The typical pricing approaches included static tariff plans that were designed given average wholesale prices. Main aim of such plans has been the maintenance of the sales volume ensuring certain revenue levels. In contrast to that, by triggering demand response, extra challenges arise and higher profitability opportunities emerge as the role of the supplier may become more active, through the optimization services that are internalised.

Such challenges and opportunities are just a part of the optimization operations of an aggregator, a new market player that aims to optimise the use of any kind of distributed energy resources under a combination of business models. Distributed generation assets, energy storage systems and the controllable loads can be coordinated and operated together, forming a sufficient capacity for participation in markets and creating economy of scale conditions that make such value propositions viable. Additional business models may include the provision of services to distribution system operators (DSOs) for active

[4] Chrysanthopoulos, N., Papadaskalopoulos, D., & Strbac, G. *et al.*. "D3.2 - Characterization of new flexible players," TradeRES project deliverable D3.5: p. 65, 2021. Available at: https://traderes.eu/wp-content/uploads/2021/07/D3.3_DesignAncillaryServiceMarketsProducts.pdf (accessed on 25.07.2021).

network management, the provision of security of supply services during emergency conditions and the participation in local energy trading. This realization potential of aggregators in several market structures has been discussed in D3.5, where the challenges around distribution network management and the value stack that emerges from business model combinations have been highlighted. Activities included in the aggregation operations are presented in Figure 1, which is an adapted schematic of the aggregator overview of IRENA [12]. Beyond the optimization routines that can lead to more efficient scheduling and coordination, the adopted forecasting approaches used for anticipating the demand, the supply and the system prices play also a vital role. This information can be either generated internally or acquired by third-parties and used as it is or being refined since the less bias is introduced, the closer to optimality the outcome gets. For the optimization part, a dynamic programming approach seems suitable, while different strategies may enable the consideration of different behavioural characteristics. Additionally, the temporal flexibility aspects related to load shifting and energy storage operations that take place on the aggregation level are discussed in D4.1.

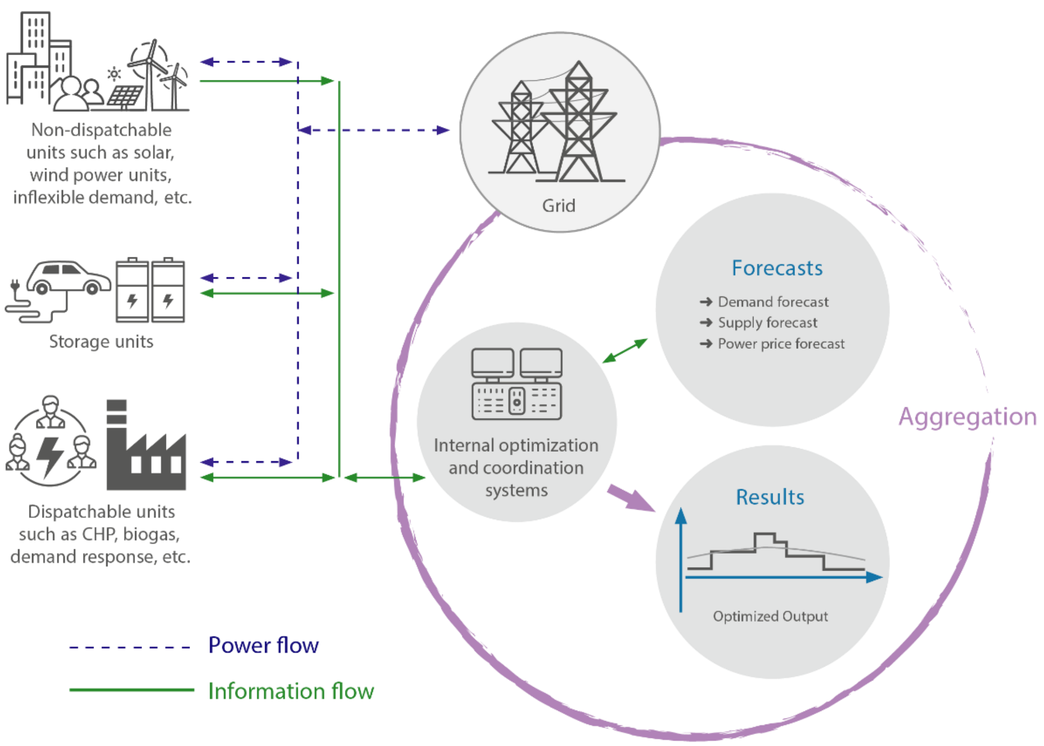

Figure 1: Aggregation operations, including forecasting, optimization, coordination activities

Given the bridge that aggregation offers between wholesale- and retail-scale sides, for its representation into models certain key operational aspects of the micro-founded environment have to be considered. As mentioned in D3.2, demand side operational characteristics related to the demand profiles, the load shedding actions and the demand side response representation (Shiftable fixed cycles, Continuously/discretized adjusted power) as well as storage (Min/Max energy limit, Charging/discharging power) and distributed generation (Generation profile, Curtailment action, Ramp limit, Up/down time) operational characteristics are among the important ones. As these characteristics are inherited from the DERs, the asset portfolio is considered important and its formation is dynamic in a competitive way, with coalitions being evolving over time. Of course, this level of detail is out of the scope of TradeRES and especially if the highly competitive environment of a retail market is considered then the portfolios not being dynamic seems natural. Additionally, this does not prevent the incorporation of optimal portfolios and the consequent implicit or explicit representation of aggregating entities. The former would include pre-aggregated resources under simplifications losing some low-level details, while the latter would analytically incorporate the several assets either under leasing schemes, or dynamic contracts and real-time pricing concepts. Versions of the implicit representation seem to suffice for studying the retail market side the relation that is developed with the energy and balancing markets.

A much more detailed consideration of aggregating agents is performed in D4.4, where agent-based models (ABM)s present current modelling approaches around agents and sketch modelling enhancements for the incorporation of emerging concepts.

Contribution to the electricity market models under development in TradeRES: allows to analyse the participation of flexible resources in the market through aggregators

Input data: characterization of aggregated demand with their willingness to pay / shift

Output data: Aggregated dynamic demand response

4.4 Prosumers

Prosumers are the first class of actors defined in D3.2 and by being the end-users and owners of distributed energy resources are in the heart of the retail market. Traditional consumers are also included in the prosumer class, as prosumers with zero generation and storage capacity, with the justification of the adopted convention laying on the fact that prosumers will prevail towards the 100% renewable generation era. Moreover, prosumers as the final users or groups of users consume, store, self-generate, participate in flexibility or energy efficiency schemes, in a not primary commercial or professional way. They are distinguished based on their type to residential, enterprise, industrial prosumers, while the group instance can be expressed through the community prosumer.

By owning assets of several technologies, which may be related to inflexible demand, controllable load (demand side response, electric vehicles, flexible heating and cooling), energy storage systems (batteries, electric vehicles) and distributed generation (photovoltaics, wind turbines, combined heat and power, etc.), they incorporate the operational characteristics mentioned in the previous subsection as owners of the assets. Their most dominant characteristic, which differentiates them from all other actors, is the utility maximization principle that governs their behaviour. Their needs have been the main driver for the establishment and evolution of the system as they set the demand side, while at the same time prioritization and shifting of loads enhances elasticity, short-term local storage adds extra time-coupling opportunities offering further flexibility and self-generation offsets the external energy requirements.

Prosumer agents may be related to inflexible, although curtailable, demand, which can be represented through input time series that follow the spatial and temporal resolution of the model. The part of the demand that can be shifted can be incorporated either through assuming continuous or discretized power blocks or through fixed, deferrable cycles that represent certain devices and uses, as is shown in Figure 2, with the former being characterised by its simplicity and the latter being closer to reality [13]. Computation time can become a significant challenge in case of large systems, in which case a more aggregated approach may be necessary. A hybrid form, with continuous intervals instead of fixed cycles, but discretized states, is implemented in AMIRIS. A planning algorithm that implements a dynamic programming approach for load shifting is described in D4.1. Energy storage systems like the batteries behind-the-meter constitute an extra source of flexibility that prosumers may use internally for reshaping their profile or lease its operation to an aggregating entity. Such assets may be incorporated via operating constraints that refer to their operating state of charge range, charging/discharging power limits and efficiencies. Regarding the flexibility emerging from sector coupling, electric vehicles and the space/water heating loads are among the technologies that are taken into consideration in the modelling, with a more detailed analysis being foreseen in D4.2.

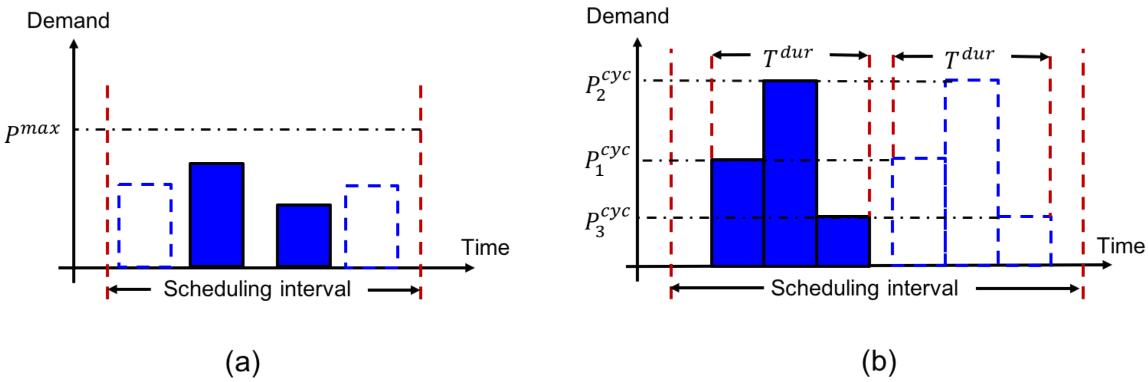

Figure 2: Flexible load modelling options; (a) Continuously adjustable power and flexible shift intervals, (b) Fixed cycles and discretized power states

Regarding the explicit representation of prosumers, this can take place through representative agents that incorporate certain of the functionalities described, with the areal distribution being subject to the spatial resolution of the models. Multi-agent approaches are conceptually closer to the distributed representation of prosumers, while the alternative would include the consideration of prosumers after aggregation. The challenge that has been mentioned in D3.5 about the loss of diversity into price-signal responses and the consequent concentration effects that may arise by the application of dynamic pricing are well known obstacles around the distributes form of demand side response that involves individual prosumers. A more in-depth consideration of the prosumer agent modelling principles and the enhancing directions proposed can be found in D4.4.

Contribution to the electricity market models under development in TradeRES:

Provides insights to the contributions of prosumers to the system's demand side response

Input data: Characterization of prosumer portfolios, similar to aggregators

Output data: Changes to load shifting/shedding and its effect on system adequacy

5 Transmission networks

5.1 Tariffs and congestion management

Transmission network tariffs usually consist of i) a fixed component (a connection cost), ii) a component that is related to consumption, i.e. a volumetric component (a charge per MWh of consumption) and iii) and a peak component (a charge per MW of peak consumption). Currently, the consumption peaks of small consumers are not measured, but in principle this can be done with the use of smart meters. Volumetric and peak components may influence network usage directly. The fixed component can only be expected to influence the behaviour of network users at the time of investment decisions, or if consumers have a choice of an alternative energy infrastructure such as hydrogen.

Unfortunately, there is no electricity network tariff design that provides optimal incentives to network users. One reason is that network expansion costs are ‘lumpy’: network expansion takes place in sizeable quantities, not in a continuous mode. As a result, the capital cost of a network increases in steps as network use increases, which means that the marginal cost of the network has extremely high spikes at the points where a step increase in capacity is needed. Marginal-cost pricing would therefore hit some consumers occasionally with extremely high prices: the marginal consumer causing the last unacceptable bit of congestion would be faced with the full cost of expansion, which is not acceptable. A second reason is that marginal cost pricing has been proven to be not sufficient for natural monopolies in the regulatory economics literature since their average costs are higher than the marginal costs. As a result, network tariffs do not reflect marginal cost [14].

A second reason for this is the collective nature of networks: network flows that oppose each other cancel each other out and thereby reduce network energy losses, which are a function of the flow. Flows in the same direction, on the other hand, cause a quadratic increase in energy losses. As a result, the marginal cost of a transaction depends on all the other transactions that occur at the same time, making the cost of each transaction difficult to calculate. Consumers, however, require predictable tariffs. A third reason is that marginal cost pricing does not lead to network cost recovery [14].

As a consequence, actual network tariffs may not provide network users with sufficient incentives to avoid network congestion. Separate congestion management methods are therefore applied in Europe. The EU prefers flow-based market coupling for cross-border links (interconnectors), while the preferred method for solving temporal congestion is redispatch and market splitting for structural intra-zonal congestion [15] [5]. The payments to redispatched generators can either be cost-based or market-based. Locational marginal

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[5] See also https://www.entsoe.eu/network_codes/cacm/implementation/sdac/.

pricing, which is applied in the USA, is considered to lead to more efficient dispatch decisions [16], [17]). This has not been implemented in Europe so far, but Poland is planning it [18], [19] . The result could be a step-wise approach, in which first the cross-border flows are determined through a zonal market clearing approach as is currently already done in the EU with EUPHEMIA, after which intra-zonal congestion is handled with locational marginal pricing [20]. This approach is less efficient than clearing the entire market through a single integrated locational pricing algorithm but appears to be more feasible in the EU.

The design of network tariffs and congestion management methods requires careful balancing of conflicting objectives; cross-subsidies and economic inefficiencies tend to appear as inevitable. As this issue is not particular to an all-renewable energy market, no new solutions will be developed within the TradeRES project. However, the impact of network tariffs and congestion management on operation and investment cannot be ignored. Therefore, existing tariffs and congestion management methods will be included in the model analyses when they are expected to play a role.

In model studies that involve multiple countries, cross-border network constraints must be represented to avoid outcomes that rely on unrealistic cross-border flows. A full representation of network flows is elaborate and may not always be necessary. Instead, a common approach is to model bidding zones as single nodes and represent cross-border network capacity as fixed constraints. Cross-border congestion is handled as market coupling, leading to zonal price differences [21]. In the models developed by TradeRES, this approach will be adopted, as a principle.

5.2 Dynamic line rating

The limiting factors for the transmission capacity of overhead lines (OHLs), i.e., the maximum allowed current (usually called *ampacity*) are established based on two main criteria: maximum conductor temperature, and minimum distance above ground – or clearance [22]. Usually, to accomplish these factors, TSOs use a static line rating (SLR) methodology to assess the lines ampacity [23]. This methodology determines the line’s ampacity from constant weather conditions using: i) seasonal basis information or ii) conservative conditions. For example, the typical values applied by TSOs range between 0.50 - 0.61 m/s for wind speed (direction is neglected), 1000 – 1150 W/m2 for solar irradiance. The temperature can be adjusted monthly, and spatially in summer (Portugal case) or seasonally (Spain), according to the highest temperature expected for each region [23].

Most of the time, these references values (strongly) underestimate the real transmission capacity of OHLs leading to vRES curtailment, grid congestion, namely, market splitting, and redispatch occurrences bringing economic losses to market participants. Grid reinforcements to reduce the occurrence of market splitting are costly and require long planning periods and complex approval procedures. Moreover, careful cost-benefit analyses of the investment costs against the benefit of reducing the occurrence of such events are needed. Therefore, new approaches to exploit the existing power network within the actual smart context assets are crucial.

One of the most promising approaches is the use of dynamic line rating (DyLR) analysis. Considering the cooling and heating cable effect' and its inertia, the DyLR analysis can estimate the ampacity value, which the OHLs may be operated at each time based on the weather conditions, Figure 3. This type of procedure led to the development of detailed numerical models such as the CIGRÉ ([24] , which has been applied successfully to different geographical regions demonstrating that DyLR has significant potential to increase the cable ampacity' [25]. DyLR can be applied to all OHL power lines but accordingly with the goals of this project it will only be applied on the interconnection lines to (potentially) increase the cross-border capacity.

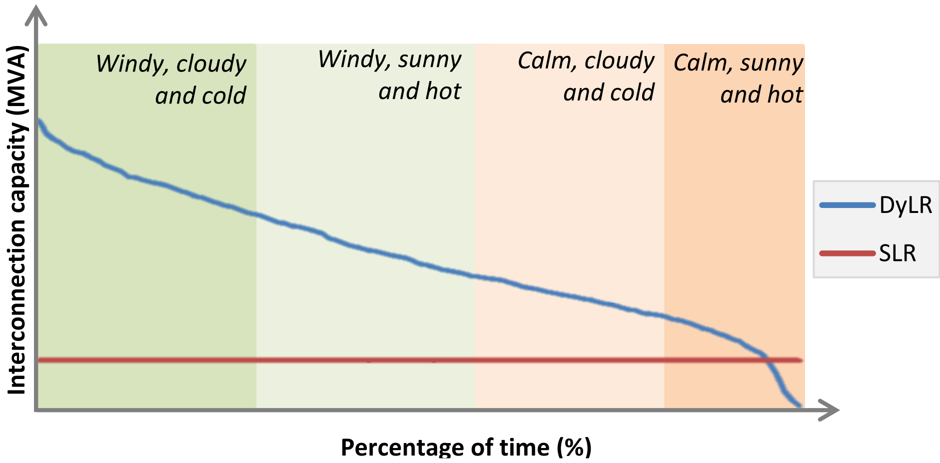

Figure 3 Interconnection capacity using a DyLR analysis versus SLR analysis

According to several authors, the DyLR enables to increase, on average, 10 to 30% of the thermal capacity over the transmission line's capacity estimated using SLR without jeopardizing the cable characteristics [22], [26] . Due to the synergy between the increased wind power generation and the line capacity (associated with convective cooling effect) the DyLR concept was initially applied in regions with high wind power potential. Nevertheless, recent studies also highlight the benefit in regions with high wind and solar potential as well as for interconnection power lines. Belgium's TSO, Elia identified that the thermal capacity (due to wind cooling) of OHLs is more than 200% of the projected SLR [25]. Although other transmission system assets (as transformers and circuit breakers having lower ratings) may reduce the benefit from applying DyLR to OHLs, recent studies show DyLR can provide a cost-effective generation dispatch [25].

In this project and for RESTrade and MASCEM models (and application to MIBEL), the DyLR analysis implemented in [23] is used to feed the agent representing the TSO. A software module was created as depicted in Figure 4. The module is based on CIGRÉ approach [24].

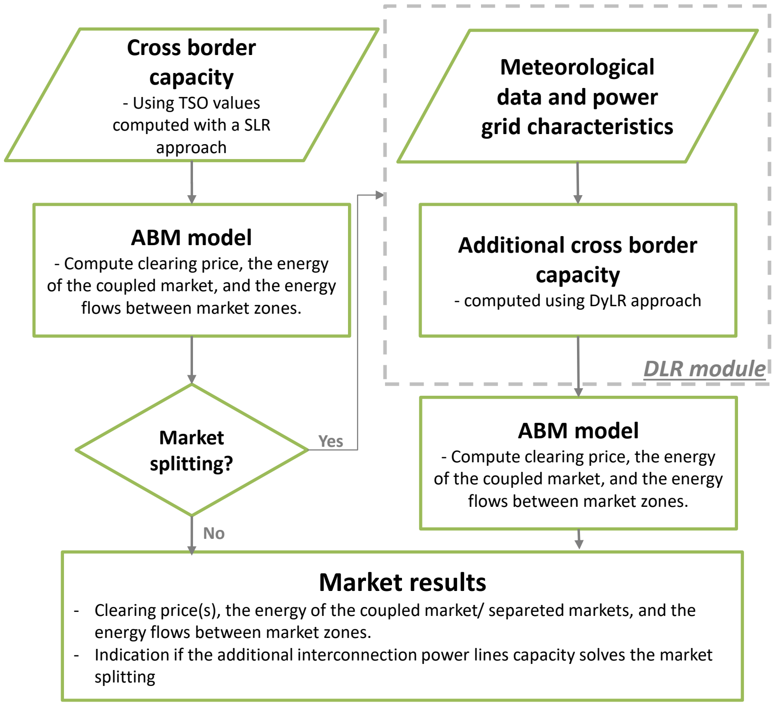

Figure 4 : Main steps used to feed the TSO agent aiming to reduce the market splitting occurrences

The DyLR module is applied for every hour where market splitting is identified in the day-ahead or intraday markets. For these hours, the DyLR analysis is used to verify if there is an extra capacity for cross-border trade compared with the assumed SLR of each interconnection line. If an extra capacity is available, the interconnection capacity between regional power systems using the DyLR result is recalculated. This information is then used by the ABMs to compute the clearing price, the energy of the coupled market, and the energy flows between market zones for the different market products.

If the energy flows are higher than the cross-border capacity between market zones, even with the extra interconnection capacity attained with DyLR, the markets are separated by the different market zones. In this case, the clearing price and energy are computed to each market zone, receiving as explicit supply (importing) or demand (exporting) bids the available energy for cross-border trades.

Due to the data requirements and specifications, this module will not be applied to all case studies foreseen in this project and, in principle, will be only tested for the MIBEL case study.

Contribution to the electricity market models under development in TradeRES: Provides the hourly additional cross-border capacity based on a DyLR analysis; It is only applied when market splitting occurs using the SLR approach.

Input data: It requires the identification of market splitting occurrences. To apply DyLR, the following is necessary *i)* meteorological data – wind speed and direction, solar irradiance and air temperature for the interconnection lines, and *ii)* transmission and distribution networks data – georeferenced layout and topology of the interconnection lines and their electrical characteristics (e.g., type of cable, number of cables, SLR, height above the sea level, etc.).

Output data: Hourly additional interconnection capacity based on a DyLR analysis.

5.3 Congestion in transmission and distribution networks

TradeRES has developed a Power Flow Service (PFS) with the purpose of validating the network feasibility of market results. This service supports any type of power network, including distribution and transmission networks, having a significant impact in impact on system adequacy, RES remuneration and balancing.

The PFS is a web service built with Django, that utilizes the *pandapower* library [27] to define and evaluate electrical networks. *Pandapower* consists of an open-source python tool capable of analyzing distribution and transmission systems [28] by using the power flow analysis to obtain the voltages at the buses, as well as the line flows and the system losses ([29] . This service allows several types of requests using both JSON and Excel as input and output and allowing the definition of every element of an electrical network, as long as it exists in the *pandapower* library. The schemas built to validate the inputs of this service also allow different types of power flow algorithms, so that the user can choose the one that applies better to the scenario that needs to be tested. At last, the result type (JSON or Excel) can also be configured in the input, so that the user can choose the one that he/she is most comfortable with. This service provides several types of requests, such as the definition and evaluation of a network, the evaluation of a saved network with new buses' loads and generators, and the retrieval of both the validation schemas for each one of the requests and the saved networks. This consists of a very flexible and fast way of evaluating electrical networks, not requiring any programming knowledge, and permitting its integration in other applications and tools.

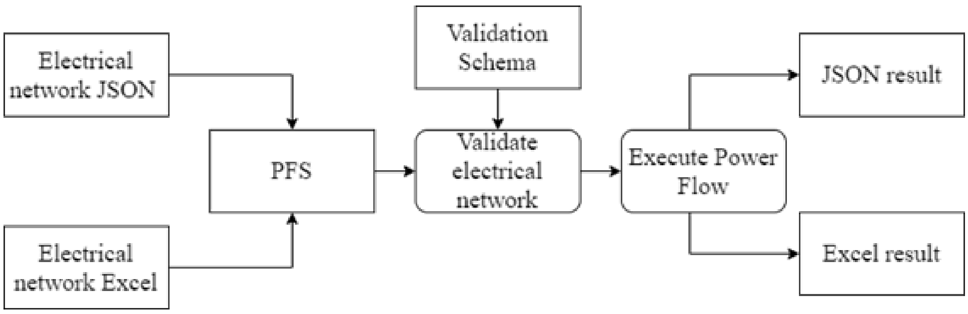

Figure 5: PFS information flow

The validation of the electricity network is made considering the equation (1) - (5), Equation (1) and (2) correspond to the constraints for buses.

$$V_{(i,t)}^{\min} \leq V_{(i,t)} \leq V_{(i,t)}^{\max} \quad \forall i \in \Omega_{\mathrm{B}}, \forall t \in T \tag{1}$$

$$\theta_{(i,t)}^{\min} \leq \theta_{(i,t)} \leq \theta_{(i,t)}^{\max} \quad \forall i \in \Omega_{\mathrm{B}}, \forall t \in T \tag{2}$$

where, $V_{(i,t)}^{\min}$ and $V_{(i,t)}^{\max}$ corresponds to the minimum and maximum limit for the voltage magnitude buses, $V_{(i,t)}$ corresponds to the voltage magnitude bus in p.u., $\theta_{(i,t)}^{\min}$ and $\theta_{(i,t)}^{\max}$

corresponds to the maximum and minimum angle value, $\theta_{(i,t)}$ is the angle value bus, i is the referred bus, t correspond to the period, Ω_{B} is the set of buses and T is the total number of periods. The maximum power flow in each line is given by equation (3).

$$0 \leq FlowS_{(i,j,t)} \leq FlowS_{(i,j)}^{\max}, \forall (i,j) \in \Omega_{\mathrm{l}}, \forall t \in T \tag{3}$$

where: $FlowS_{(i,j,t)}$ corresponds to the flow of line between bus i to bus j and $FlowS_{(i,j)}^{\max}$ is the maximum value admitted in line of bus i to bus j, Ω_{l} corresponds to the set of lines. The active power is constrained by the maximum and minimum capacity that can be supplied (4).

$$P_{SMinLimit(bs)} \leq P_{Supplier(bs,t)} \leq P_{SMaxLimit(bs),} \forall bs \in \Omega_{\mathrm{BS}}, \forall t \in T \tag{4}$$

where: $P_{SMinLimit(bs)}$ and $P_{SMaxLimit(bs),}$ corresponds to the minimum and maximum limit for supply element, $P_{Supplier(bs,t)}$ corresponds to the value of supply element and Ω_{BS} corresponds to the set of supply elements. The reactive power is constrained by the maximum and minimum capacity that can be supplied (5).

$$Q_{SMinLimit(bs)} \leq Q_{Supplier(bs,t)} \leq Q_{SMaxLimit(bs)}, \forall bs \in \Omega_{\mathrm{BS}}, \forall t \in T \tag{5}$$

where, $Q_{SMinLimit(bs)}$ and $Q_{SMaxLimit(bs)}$ is the minimum and maximum limits for the reactive supplay elements, $Q_{Supplier(bs,t)}$ is the reactive energy value supplied. To obtain the test values the power flow service is run. Several parameters of *pandapower* can be adjusted according to the scenario, see the *pandapower* documentation[6].

When distribution networks are congested, this can be managed through variable network tariffs, e.g. tariffs that increase in real time to reflect the level of congestion. Alternatively, if the network tariffs are constant, a separate congestion method may be applied.

As network tariffs do not reflect the marginal social cost of network usage, they cannot fully prevent congestion. Therefore, separate congestion management methods have been invented. There are two broad categories: i) congestion pricing and ii) flexibility markets. An example of the first is locational marginal pricing, in which local prices are varied in order to attract more generation and less consumption, or the other way around, and thereby adjust the network flows to fit the available network capacity. This method increases the price of network usage for market actors who cause the congestion and therefore yields revenues, but it has been shown that they should not simply accrue to the network operator as it provides an incentive to limit network capacity to increase revenues ([30], [31] . In a flexibility market, the monetary flow is opposite: there, the DSO pays parties to relieve congestion. While this is more easy to implement, local flexibility markets are highly susceptible to market power, e.g. in the form of inc-dec gaming [32].

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[6] https://pandapower.readthedocs.io/en/v2.0.0/powerflow/ac.html (accessed XX)

It is not in the scope of TradeRES to model possible distribution network tariffs and congestion management options.[7] The topic is large and complex, while it is not particular to a renewable electricity system. Therefore, in TradeRES, as a principle, we will not model distribution network tariffs and congestion.

Contribution to the electricity market models under development in TradeRES: Power flow modelling

Input data: network injection and withdrawal data

Output data: network load

[7] A project in which this is done is the STEP-UP Project, in which the TU Delft work package focuses on this precise problem. See https://www.stepupsmartcities.eu.

6 System adequacy

One of the main research questions to be addressed by TradeRES models is whether an energy-only market provides sufficient flexibility and incentives for investment in dispatchable resources to achieve adequacy in the future power system. With 'dispatchable' resources, we mean all kinds of resources that can help compensate for the variability of vRES: controllable electricity generation, e.g. from hydrogen, hydropower or biomass, energy storage, demand response and sector coupling. In the negative case, if the market does not provide enough investment in these flexible resources, the next question is, which capacity mechanism design is the most attractive for power systems with high shares of vRES.

The second main question in this project, whether markets provide enough incentive to invest in vRES, is complementary to this one and will be discussed in Chapter 9 of this report.

The interactions between modifications to the wholesale market and capacity mechanisms will be evaluated. To evaluate capacity mechanisms, a situation of prolonged scarcity of wind and solar energy will be considered. Even when a power system is designed to have an annual average vRES capacity to supply the yearly average consumption, there will be energy deficit and surplus periods. The challenge is therefore to provide an optimal combination of energy storage, dispatchable generators and demand response in the system, i.e., a cost-minimal mix from a macroeconomic point of view. This requires to design the market and regulations in such a way that they provide the socially desired volume of each of these technologies and services. The scenarios and the indicators to test the implementation of the model of capacity mechanisms to different case studies will be described in work package 5.

6.1 Modelling approach

To simulate if investors will have enough incentives to invest in generation capacity, it is a requirement to take into consideration that investors in reality do not have perfect foresight (of demand, the capacity planned by competitors, the regulation modifications, etcetera). Investment behaviour will be modelled with the ABM EMLab. (See Deliverable 4.6[8] for a description of EMLAB, which provides the investment algorithm that we will use, and Deliverable 3.5 for a detailed description of capacity mechanisms). In EMLab, investments will only be made if the investor can have a reasonable expectation that the net present value of the investment will be positive, based on information that is available at the time of investment and the incentives, such as the prices of electricity and CO_2.

[8] Schimeczek, C., Rinne, E., *et al*. "D4.6 (D4.3.1) - Market model communication interfaces," TradeRES project deliverable 4.6: p. 53, 2020.

The objective of the optimization models in the consortium (COMPETES, BACKBONE), by comparison, is to find the macroeconomic least-cost investment strategy. The ABM simulations will be compared with the results of the optimization models in order to determine the efficiencies of the different market design options and identify the optimal market options to be simulated in detail with ABM for different scenarios. The optimization models will indicate the best possible investments, from the perspective of society and given a certain scenario. The ABMs will provide insight in realistically expected investment behaviour, given the market prices, the regulatory incentives and the limited time horizon of investors.

Because optimization models are simpler to create and computationally faster, they are able to cover a wider geographical scope. Wholesale prices resulting from those models can therefore be used to assess revenue streams and market dynamics on the Pan-European level based on a market characterized by installed capacities resulting from investment decisions modelled in the ABMs.

6.2 Energy-only market

When assessing if the current energy-only-market (EOM) design provides sufficient incentives to achieve system adequacy, it is crucial to carefully model the price level and occurrence of peak prices in the energy-only-market. That is because with their dispatch times expected to decrease in a power system mainly based on wind and solar energy, dispatchable technologies, such as storage facilities and hydrogen-based power plants, require a sufficient number of hours with high peak prices above their marginal costs to recover their long-term investment costs in an energy-only-market [33]. In theory, peak prices should reflect consumers' willingness to pay and thereby incentivize exactly the volume of dispatchable capacity that provides the level of security of supply that is desired by consumers, given the cost of these dispatchable technologies.

Therefore, for TradeRES it will be important to model demand-side flexibility as well as dispatchable generation in detail, both in the ABM simulations and in the optimization models. Particular aspects of flexibility resources that need to be considered in the models are:

- Capacity and energy volume that can be provided (by storage) or shifted (by demand);
- Cost (of generation and storage) and willingness to pay for secure supply or accept curtailment (of demand).

In AMIRIS, one of the models that is used for the analysis, load shedding is represented by dividing the overall electricity demand time series into segments and providing each segment with a baseline demand time series as well as a value of lost load (VOLL) that reflects the consumer groups' willingness to pay. Demand-side bids are placed at this price by the demand trading agent. Thus, a more granular aggregated demand curve is intersected with the supply-side merit order. Load shifting in turn is represented using a dynamic programming approach and accounting for shift times as well as load shift energy levels and the restrictions in terms of power, energy and shift times. D4.1 contains a description of the implementation.

Beside this flexible resources and demand, the EOM will be analyzed with the increased flexibility that results from the modifications to the regulation of the market as described in Sections 2 and 3.

6.3 Capacity mechanisms

Several capacity mechanisms will be modelled in order to evaluate their impact on system adequacy and the cost of electricity to consumers. Many capacity mechanisms have been devised and tried out [34]. We will focus on three types: capacity markets, as they are commonly implemented, capacity subscription, as it is a promising innovation (see also Deliverable 3.5); and a strategic reserve, as the EU prefers this method. The EU has specified requirements for capacity mechanisms, but in our analyses, we will take an open view of the market design options.[9] In the next subsections, the proposed implementation of the capacity mechanisms will be described, based on their implementation in EMLab.

6.3.1 Capacity market

Two types of capacity markets have been modelled in EMLab, the forward capacity market and the yearly capacity market. The forward capacity market follows the UK rules, as it is the first capacity market in Europe and one of the few ones with forward contracts. The generation that bids successfully in the forward market should be available four years ahead (reference year). The new plants win a contract of 15 years while existing plants are awarded a one-year contract. The refurbished plants are not modelled. Power plants that forecast a positive revenue for the reference year bid 0 and become price takers. Plants that estimate negative revenues bid the difference between the estimated net revenues (revenues minus marginal costs) and the revenues needed to cover the fixed costs. Power plants that have been awarded a long-term contract cannot participate again in the auctions for the duration of the contract. For the demand side, the regulator sets the installed reserve margin r to calculate the demand requirement D_r (6). The awarded long-term capacity C_{LT} and the capacity awarded with RES support C_{RES} are subtracted from the peak demand D_{peak} [32]

$$D_r = (D_{\mathrm{peak}} - C_{\mathrm{LT}} - C_{\mathrm{RES}}) \times (1 + r) \quad (6)$$

[9] Regulation (EU) 2019/943 of the European Parliament and of the Council on the Internal Market for Electricity Art. 22 mentions some requirements for the implementation of the capacity mechanisms. They should be temporary, planned for no longer than 10 years, should not create market distortions, not go beyond the necessary adequacy capacity, assign the support in a competitive manner, be open to all resources able to provide capacity in scarcity (including energy storage and demand side response), in case the plants are not available in stress times a proper penalty should be assigned. Mechanisms other than strategic reserves should ensure that the remuneration does not affect the decisions of the capacity on whether to generate or not. Capacity obligations should be transferable. Finally, the participating generators should consider certain emission limits as explained in Art 22(4).

The capacity market cap P_C is set by the consumers maximum willingness to pay (7)-(9). The slope of the demand curve was modelled as in the New York Independent System Operator (NYISO) Installed Capacity (ICAP) market and PJM capacity market on the East Coast of the USA considering an upper margin um and a lower margin lm for a demand slope m.

$$m = \frac{P_c}{LM - UM} \tag{7}$$

$$UM = D_{\text{peak}} \times (1 + r + um) \tag{8}$$

$$LM = D_{\text{peak}} \times (1 + r - lm) \tag{9}$$

The capacity market is modelled as a uniform price auction where the bids are sorted in an ascending order [35].

The yearly capacity market was modelled assimilating the NYISO-ICAP market rules. The difference is that awarded power plants need to be available the following year of the auction. The ISO contracts the capacity on behalf of the load serving entities (LSE). The LSEs are obligated to buy credits according to their forecasted peak demand and a reserve margin. In EMLab this capacity market is modelled in the same way as the forward capacity market, in a yearly auction and with a sloping demand curve, albeit the demand requirement D_r is calculated as follows (10):

$$D_r = (D_{\text{peak}}) \times (1 + r) \tag{10}$$

6.3.2 Capacity subscription

In a market with capacity subscription, consumers choose the level of reliability they prefer for scarcity situations by paying for a certain capacity, e.g. several kW per household, that they are always wanting to be able to consume. Under normal conditions, they may consume more, but during periods of energy shortage they will be limited to their maximal contracted capacity. The payments benefit the generation companies by providing a clear investment signal and a stable revenue for dispatchable capacity. This mechanism assumes that consumers have an electricity meter that allows them to charge real time price rates.

To model capacity subscription, the main requirement is to parametrize the demand side response. The supply side is the same as in a capacity market model. The willingness to shift can be differentiated according to consumer classes, considering their maximal shifting time, the response time (ramp rates) and a percentage of the demand (MWh) and of the capacity (MW), according to price thresholds (willingness to shift).

To model capacity subscription in an agent-based model, each type of consumer can have a different value for reliable supply. The price of subscription can be modelled as a function of the peak demand of the different consumers. To calculate the cost of the capacity subscription, the supply curve can be modelled with the bids of the power plants as in the capacity markets. In an optimization model that serves as a reference, consumer flexibility needs to be modelled with the same parameters.

6.3.3 Strategic reserve

The European Commission has established in Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the Internal Market for Electricity, [15] Article 21 (General Principles for capacity mechanisms) that the member states should evaluate if a strategic reserve is capable of addressing the resource adequacy concerns. Only if this is not the case, another mechanism may be implemented.

A strategic reserve is under the control of the TSO, who designates a volume of generation capacity to be held in reserve. This capacity is kept out of all markets and is activated only in scarcity situations. The TSO covers the fixed costs of power plants that have a low probability to be called in the wholesale market in order to avoid their mothballing. In case the plants are activated, the TSO keeps the difference between the market revenues and the marginal costs of the plant to offset the cost of the reserve. The European regulation enlist the requirements for the strategic reserve in Article 22 (Design principles for capacity mechanisms). These are: "the strategic reserve resources should be dispatched after the TSO exhausted their balancing resources; during imbalance settlement periods, imbalances in the market are to be settled at least at the VOLL; the output of the strategic reserve should be attributed to balance responsible parties through the imbalance settlement mechanism; the resources of the strategic reserve should not participate in the wholesale and balancing markets for the contractual period".

Bhagwat et al. [36] implemented a strategic reserve in EMLab. To determine the parameters, they considered that the reserve price should be determined such that the revenues earned with the strategic reserve should be equivalent to the revenues from an EOM (to avoid changing the average electricity price for market parties).

Contribution to the electricity models under development in TradeRES: Investigates the need for and performance of capacity mechanisms in an all-renewable energy system, considering future flexibility options; Capacity subscription is a new mechanism that will be modelled.

Input data: It requires forecasted revenues from the wholesale market (yearly unit production and average unit production price) fuel prices, fixed O&M costs, unit capacity, unit efficiency, parametrization of demand side response (for capacity subscription).

Output data: Assigned capacity mechanism support per unit, electricity price per time unit, total cost of electricity (including the cost of the capacity mechanism) to consumers, system adequacy

7 Sector coupling

The future power system will be characterized by a higher level of interaction between the heating, industrial, transport and electrical sector. For example, the recent European plans for a green hydrogen strategy can enhance the system flexibility. This flexibility should be considered to estimate the need for installed capacity in scarcity situations. The D4.2 will outline the consortium modelling capabilities and its enhancements in this regard.

Deeper coupling of different energy sectors also has impacts on the different market aspects discussed in this report. In some cases, it might be beneficial to have multiple energy sources for a single purpose. For example, some heating solutions might be based on electricity *and* fuels – e.g. hydrogen in the future – as well as increased heat storage capacity. In such situations, the owner of the asset might need to consider multiple markets for different energy commodities and even markets for emission allowances for making a least cost decision. The design of the different markets should enable this kind of multi-market situations. Furthermore, an operational question might be whether it is more profitable to buy, sell or store energy which can be converted to and from various forms or other products, and the different commodities have their separate markets.

Similar to the multi-commodity situation above, the owner of an energy asset might operate on multiple ancillary service markets. These are mainly related to electrical energy balance and frequency stability, but the asset might be converting one form of energy to another and therefore multiple sectors are involved. Again, ancillary service markets should be designed to enable trading in multiple (energy) commodities simultaneously.

System adequacy can be achieved through enough generation capacity that can always be dispatched at will. Energy sector integration involves conversion of energy into different forms, some of which are more economical to store. This allows for more dispatchable generation. Energy sector integration should be considered as an option for increasing or maintaining power system adequacy.

Contribution to the electricity market models under development in TradeRES: availability of hydrogen as a fuel for power generation; demand for hydrogen

Input data: electricity prices (for hydrogen production); cost and performance data of electrolysers; hydrogen demand; hydrogen network and storage data

Output data: cost and quantity of hydrogen production; cost and quantity of hydrogen consumption for electricity generation

8 Carbon policy

In an all-renewable energy system, there is no need for a carbon policy. In TradeRES, carbon policy will be included in model analyses of interim steps in the energy transition. The modelling of carbon policy will be based on the European Emission Trading System and possible changes to it.

The European Emission Trading System (ETS) is the main policy instrument in the European Union for reducing greenhouse gas emissions. It works according to the cap-and-trade principle, implementing a ceiling on total CO_2 emissions and allowing trade of emission rights to allow for the most cost-efficient emissions reduction options. To stabilize the prices, the EU has introduced a Market Stability Reserve. In the past years, this mechanism has passed through several reforms. From 2021 onwards, the annual rate of emission allowances will reduce by 2.2%. On July 14th 2021, the intermediate target for greenhouse gas reduction was set to 55% by 2030, compared to 1990 which requires for a stronger reduction rate. Furthermore, a separate scheme for traffic and the heating sector not yet covered by the EU ETS shall be set up[10]. A more extensive explanation of the basic policy and its status and late evolution is outlined in Deliverable 3.5. In this subsection we will focus on the modelling approach for this policy instrument.

At the most basic level, a CO_2 market can be implemented as an annual auction of CO_2 credits. The auction volume is set exogenously, as in reality it is set by the government. The demand for CO_2 credits stems from the facilities that emit CO_2 – in our models, the power plants. Per power plant, the demand is equal to the expected emissions in the next year and the willingness to pay for CO_2 is equal to the expected market revenues minus operating costs. Thus, by dividing the expected operating margin by the associated emissions, a maximum price per ton of CO_2 is derived.

This method may lead to highly volatile CO_2 prices. Therefore, it is necessary to add a module that represents a forward market for CO_2. By simulating intertemporal arbitrage, CO_2 price volatility will be dampened to a more realistic level. The forward market for CO_2 should be based on a simulation of supply and demand in a future year. The supply of CO_2 credits is regulated (we will assume a reduction path in accordance with the EU Green Deal); the demand can be simulated by accounting for changes in energy demand and the electricity generation portfolio. If the future price of CO_2 is expected to increase, this will lead to a higher spot price in view of the opportunity cost of using credits. This will reduce the demand for credits (i.e. the current emissions), leading to more banked credits, which will help reduce the future shortage. The other way around, if a future surplus of credits is expected, this will depress the short-term price and lead to more emissions.

[10] Press release by the Commission: https://ec.europa.eu/commission/presscorner/detail/en/IP_21_3541, (accessed 17.08.2021).

In some countries, a minimum price has been implemented to provide a stronger price signal for investment in decarbonization. By reducing the price risk of investments in decarbonization, they should take place sooner, thereby reducing CO_2 emissions as well as the average price of CO_2. This policy option will be included in the models.

The modelling of the ETS will be based on [37] who implemented it in EMLab. The reduction options in EMLab were limited, however, to fuel switching and a few low-carbon generation technologies; in TradeRES, the much more refined market representation as well as endogenous investment in vRES will provide a significant improvement in the quality of the analysis.

Contribution to the electricity market models under development in TradeRES: provides insight in the impacts of the ETS and the options of a minimum and a maximum price on CO_2 reduction pathways

Input data: CO_2 policy settings: the ETS as it is now, or the addition of a minimum and possibly also a maximum price

Output data: CO_2 emissions, CO_2 prices, investment in CO_2 reduction

9 RES support schemes

Analogous to the analysis of investment in dispatchable generation, the analysis of investment in vRES will start with an energy-only market without any kind of financial support. If the wholesale market (and its modifications) do not provide sufficient revenues to invest in renewable energy technologies, we will investigate different support instruments, namely market premia, contracts for difference, feed-in premiums, and capacity-based support [38].

It is well known that a higher volume of a type of renewable energy in a market zone may cause its market value to decrease, as its generation normally occurs in a synchronized manner affecting large spatial areas and therefore usually dominates the local market trading in such periods [39]. This is often referred to as the wind/vRES 'cannibalizing' effect' (cf. López Prol et al. [40]), but fundamentally, it is a normal phenomenon in markets that the return-on-investment declines when supply increases. A particular issue with vRES is that wind and solar PV installations have similar marginal costs (close to 0), and are basically non-dispatchable, therefore tend to remain producing as long as they have primary energy resource and as a result of which they tend not to recover much of their investment when they are setting the market price.

A second challenge is weather uncertainty, as a result of which annual revenues of vRES may vary between years, which may contribute to investment risk, even in a long-term stable decarbonized market. An increase in flexibility may stabilize future electricity prices, as was explained in Section 5.1 of D3.5, but the extent to which this will occur is uncertain. As a result, the need for financial support (e.g. acting as an environmental retrofit to RES) in an all-renewable electricity system is not clear at this time of the project, but we expect it will be known after the first round of TradeRES case study simulations (in WP5).

It is a core objective of TradeRES to investigate this issue with its models. Therefore, the base case will be a market in which vRES need to recover their costs through the market (the wholesale market plus possibly the balancing market). In addition, several types of renewable energy support instruments will be analysed. Firstly, we will model ***contracts for differences***, which are currently a common instrument, as well as two other forms of price support, namely a ***feed-in premium*** and a ***market premium***. In addition, we will model ***capacity-based support***. Capacity-based support of vRES was applied at the end of 20th century in many western countries, mainly in the European Union. This way of supporting renewable technology had variable results, some reportedly negative. One of the main issues normally pointed out was the tendency to artificially increase the investment costs of projects by developers. Subsequently, it was concluded that renewable support-schemes should be aimed at the operation/efficiency of the units and not investment. This is now the established view and has been applied, e.g. in recent projects supported by NER300 European programme and Innovation Fund.[11] However, capacity-based support has as an interesting feature, that it does not distort the short-term market incentives and may therefore contribute to more efficient market operation [41].

9.1 No vRES support

This reference option entails all vRES selling the bulk of their electricity generation through the day-ahead market. Nevertheless, their potential trading in eventually more favourable markets, similarly to the actual intraday and/or reserves markets should also be considered in the TradeRES project. In reality, they may sell their output through long-term contracts; currently, power purchasing agreements are popular. However, in an all-renewable energy market, there will be no bonuses for renewable energy, as it likely is the only energy source, and it may be expected that the price of long-term contracts will approximate the average price that the generators would have received in the short-term market. For wind and solar PV generators, this price – called the capture price – will be lower than the average market price because this price will be lower when more of their generation is available. The capture price will be monitored in the model runs to evaluate the cost recovery of all RES, variable or not.

Most TradeRES models (including AMIRIS, RESTrade, MASCEM) allow for vRES generation being marketed without support. In this case, the RES feed-in potentials are marketed at their marginal costs. Hence, traders marketing the vRES generation are not willing to accept prices below the marginal costs and would curtail the generation in this case. The optimization models within TradeRES can be applied to model wholesale price dynamics and their effects on the revenues of vRES at the pan-European level, while integrating the knowledge gained about their investment and dispatch behaviour from the ABMs.

9.2 Contracts for Differences

Large renewable projects are currently supported with contracts for differences (CFD) in a number of European countries. This instrument pays renewable generators the difference between a reference price and their market revenues, often up to a maximum number of operational hours per year. A limit on the total amount of support per MWh of energy production may also be implemented, as well as a restriction to hours in which the market price is not negative, in order to avoid an incentive to keep producing when there is a surplus of energy. Producers of RES bid competitively for the support, which is therefore awarded to the producer who needs the lowest level of support, i.e. bids to the lowest reference price. Producers bid before they build their RES installations. In case of offshore

[11] NER 300 programme | Climate Action (europa.eu), consulted on 28.07.2021.

wind parks, they bid for a package that includes permits and the network connection in addition to the subsidy.

Model implementation will hinge on the determination of the reference price. It may not be easy to emulate the bidding process, as producers' bids are determined by a number of factors such as the estimated costs of the vRES plant, financing costs and risk premia. In principle, not considering risk premia and market imperfections, the reference price should reflect the average price of electricity per unit of output, increased by the financing cost. This is therefore a suitable starting point for model implementation.

The payments are simply the difference between this reference price and the received market price. As mentioned above, they may be limited to a maximum payment per MWh, to hours in which the market price is not negative and to a maximum number of hours per year.

In summary, as a departing point, CFD will be modelled as follows:

- The **reference price** will be set equal to the long-run marginal cost of RES generation, i.e. the average cost of new RES generation units, plus the cost of financing;
- The **payments to the vRES** generators will be equal to the difference between the reference price and the market price; payments are made per unit of produced electricity. Optionally, the payments may be restricted to:
    - Hours with non-negative prices;
    - A maximum payment per MWh;
    - A maximum number of operational hours per year;
    - Whether or not to let generators pay back when the market price exceeds the reference price.

As an example, for AMIRIS, there is already an implementation of the German variable market premium scheme which can be classified as a one-sided CFD since there is no payback obligation in case the market revenues exceed the levelized cost of electricity (LCOE) (in Germany approximated by the so-called value applied of the German Renewable Energies Act – EEG 2021). The market premium amount paid is dependent on the energy carrier-specific market value which is determined ex post for a given month. The market premium is defined to be the difference between the value applied (approximately equal to the LCOE) and the respective market value. Thus, the trader is willing to offer RES capacities at negative prices with an absolute value that is smaller than the difference between the (near zero) marginal costs and the received market premium since this does reflect the opportunity cost of the support instrument.

It is planned to add CFD as a support instrument for RES support building on the given architecture. This architecture contains a central support policy agent who is attributed with all the necessary information for determining support pay-outs. This also comprises projected or at a later stage potentially modelled LCOE estimates for vRES. A trading agent markets the aggregated RES capacity infeed whereby the price depends on the opportunity costs resulting from the support instrument and its limitations (e.g. no support after a given number of hours with negative prices, caps for capacity or full-load hours). RES units are aggregated to sets of portfolios for the particular trading agent. Parameterization as well as generalization of the approach are still work in progress and to be addressed within the TradeRES case studies of WP 5 for most, if not all, case studies.

9.3 Capacity-based support

Capacity-based support of renewable energy generators does not distort the short-term market incentives. It is easy to model: generators receive a subsidy per installed MW of generation capacity. The main question is how to determine this level in the model, also in view of providing fair support for different types of renewable generation.

For AMIRIS, it is planned to add capacity premiums as a support instrument for RES, again building on the given architecture described in section 10.2. A previous implementation of a prior AMIRIS version shall be built upon [42].

9.4 Feed-in Premium

A feed-in premium provides a fixed amount of money per unit of electricity generation in addition to the market price. A single premium would increase the overall investment in renewable energy, while the differences in cost and output characteristics between the different technologies would lead to an efficient mix in which they all just recover their cost. For AMIRIS, it is planned to model a fixed feed-in premium.

A variant of a feed-in premium is a market premium. In this case, the renewable energy generator receives a fixed premium on top of the electricity price. It may be implemented with a lower limit to guarantee the economic viability of the technologies' installations and an upper limit (floor and cap prices). Spain used this option until 2010, considering a reference premium of 30.99 €/MWh, with a lower limit of 75.41 €/MWh, and an upper limit of 89.87 €/MWh.

The main difference of VRE behaviour regarding CFD vs. market premium appears to be that with a CFD, they have the incentive to produce and sell as much kWh as possible, while with a market premium they would consider the current market price and cap production at the negative price equal to the level of a market premium (considering operational costs). In case of a capacity-based premium, rational VRE producers would cap their production at any price below zero since they would not receive any revenue from that. This behaviour is expected to emerge from the agent-based model simulations in our project.

Contribution to the electricity market models under development in TradeRES: provides insight in the effects of different vRES support instruments on the development of vRES and on investment risk in vRES

Input data: vRES support instrument parameters and conditions (specification of how much support is issued under which circumstances)

Output data: investment in vRES, vRES operation, including curtailment, vRES capture prices (received market prices by vRES generators), cost of vRES to consumers

10 Final remarks

Together with the other deliverables of Work Package 4, this deliverable outlines the scope and model conceptualization of the models that will be developed and run in Work Package 5 of TradeRES project. As the models are implemented, their documentation will be refined. This document outlines the main model choices that are currently being, or will be, implemented in the suite of models that is under development by the project. System adequacy – the ability of the electricity system to meet demand under all circumstances – is a key aspect. As it depends on the availability of generation, storage and demand response at all system levels, on network capacity and on sector coupling, ideally it would require a detailed operational analysis of the full integrated system. However, because this is not feasible, a modular approach to modelling is applied to handle the large scope and computational complexity of the analysis. This approach of developing a suite of modelling extends the state-of-the-art in integrated energy system modelling.

Various policy options for system adequacy will be modelled, with the energy-only market as the reference case. Improved flexibility options will be included, with the question whether they will provide sufficient stability to the market or whether a capacity mechanism will improve the performance of the market in terms of adequacy and price stability. Existing as well as new capacity mechanisms, such as the capacity subscription, will be analysed. Contrary to existing analyses, their performance will be tested in the context of an all-renewable energy system with innovative flexibility options. The contribution of more flexibility from the wholesale market (as described in Section 2) and from aggregators (as described in Section 4) to the energy-only market and to different capacity mechanisms (as described in Section 6) will be evaluated, as well as the impact of sector coupling (Section 7).

The second main question that is addressed in this project is the degree to which variable renewable energy sources will be able to recover their costs in a future electricity market. Again, the energy-only market is the base case, while various policy support instruments will also be modelled (Section 9). And again, a key modelling question is to what degree future improvements to system flexibility will be able to absorb the fluctuations in renewable energy generation and thereby support their business case. The impact of carbon policy – the ETS and possible modifications to it, as described in Section 8 – will be included in analyses of interim steps towards full decarbonization.

In this deliverable, the enhancements to temporal flexibilities in the models were mentioned briefly, as Deliverable 4.1 enlist their details. Similarly, innovations to the governance of consumers are captured in Deliverable 4.4. With respect to transmission networks, an innovative approach to maximize the capacity is dynamic line rating, which will be evaluated in the MIBEL case study.

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