Whitepaper

ELECTRICITY MARKET DESIGN 2030-2050: MOVING TOWARDS IMPLEMENTATION

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Electricity Market Design 2030-2050: Moving Towards Implementation

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Preamble

Climate change and ambitious emission-reduction targets call for an extensive decarbonization of electricity systems, with increasing levels of Renewable Energy Sources (RES) and demand flexibility to balance the variable and intermittent electricity supply. A successful energy transition will lead to an economically and ecologically sustainable future with an affordable, reliable, and carbon-neutral supply of electricity. In order to achieve these objectives, a consistent and enabling market design is required.

The Kopernikus Project SynErgie investigates how demand flexibility of the German industry can be leveraged and how a future-proof electricity market design should be organized, with more than 80 project partners from academia, industry, governmental and non-governmental organizations, energy suppliers, and network operators.

In our SynErgie Whitepaper *Electricity Spot Market Design 2030-2050* [1], we argued for a transition towards Locational Marginal Prices (LMPs) (aka. nodal prices) in Germany in a single step as a core element of a sustainable German energy policy. We motivated a well-designed transition towards LMPs, discussed various challenges, and provided a new perspective on electricity market design in terms of technological opportunities, bid languages, and strategic implications. This second SynErgie Whitepaper *Electricity Market Design 2030-2050: Moving Towards Implementation* aims at further concretizing the future German market design and provides first guidelines for an implementation of LMPs in Germany.

Numerical studies – while not being free of abstractions – give evidence that LMPs generate efficient locational price signals and contribute to manage the complex coordination challenge in (long-term) electricity markets, ultimately reducing price differences between nodes. Spot and derivatives markets require adjustments in order to enable an efficient dispatch and price discovery, while maintaining high liquidity and low transaction costs. Moreover, a successful LMP implementation requires an integration into European market coupling and appropriate interfaces for distribution grids as well as sector coupling. Strategic implications with regard to long-term investments need to be considered, along with mechanisms to support RES investments. As a facilitator for an LMP system, digital technologies should be considered jointly with the market design transition under an enabling regulatory framework. Additional policies can address distributional effects of an LMP system and further prevent market power abuse.

Overall, we argue for a well-designed electricity spot market with LMPs, composed of various auctions at different time frames, delivering an efficient market clearing, considering grid constraints, co-optimizing ancillary services, and providing locational prices according to a carefully designed pricing scheme. The spot market is tightly integrated with liquid and accessible derivatives markets, embedded into European market coupling mechanisms, and allows for functional interfaces to distribution systems and other energy sectors. Long-term resource adequacy is ensured and existing RES policies transition properly to the new market design. Mechanisms to mitigate market power and distributional effects are in place and the market design leverages the potential of modern information technologies.

A rapid expansion of wind and solar capacity will be needed to decarbonize the integrated energy system but will most likely also increase the scarcity of the infrastructure. Therefore, an efficient use of the resource "grid" will be a key factor of a successful energy transition. The implementation of an LMPs system of prices with finer space and time granularity promises many upsides and can be a cornerstone for a future-proof electricity system, economic competitiveness, and a decarbonized economy and society. Among the upsides, demand response (and other market participants with opportunity costs) can be efficiently and coherently incentivized to address network constraints, a task zonal systems with redispatch fail at. The transition to LMPs requires a thorough consideration of all the details and specifications involved in the new market design. With this whitepaper, we provide relevant perspectives and first practical guidelines for this crucial milestone of the energy transition.

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Hans Ulrich Buhl and Martin Weibelzahl (Cluster Lead)
Martin Bichler (Work Package Lead)

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Acronyms

AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
ACOPF	Alternating Current Optimal Power Flow
aFRR	Automatic Frequency Restoration
AI	Artificial Intelligence
AIC	Average Incremental Cost
APIs	Application programming interfaces
ARR	Auction Revenue Right
BRP	Balancing Responsible Parties
CAISO	California Independent System Operator
CfD	Contract for Difference
CH	Convex Hull
DC	Direct Current
DCOPF	Direct Current Optimal Power Flow
DLMP	Distribution Locational Marginal Price
DLT	Distributed Ledger Technologies
DSO	Distribution System Operator
ELMP	Extended Locational Marginal Price
ENTSO-E	European Network of Transmission System Operators for Electricity
EPAD	Electricity Price Area Differential
ERCOT	Electric Reliability Council of Texas
EU	European Union
EUR	Euro
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
FCR	Frequency Containment Reserves
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Right
FSO	Future System Operator
HVDC	High Voltage Direct Current
IC	Integrated Circuit
ICE	Intercontinental Exchange
Inc-Dec	Increase-Decrease
IP	Integer Programming
ISO	Independent System Operator

ISO-NE	Independent System Operator New England
IT	Information Technology
LCOS	Levelized Cost of Storage
LD	Lagrangian Dual
LMP	Locational Marginal Price
LP	Linear Progamming
mFRR	Manual Frequency Restoration Reserves
MiFID II	Markets in Financial Instruments Derivative II
minRAM	Minimum Remaining Available Margins
MIP	Mixed Integer Programming
MISO	Midcontinent Independent System Operator
NEMO	Nominated Electricity Market Operator
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
OMIE	Operador do Mercado Ibérico de Energia
OPF	Optimal Power Flow
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PUN	Prezzo Unico Nazionale
RCC	Regional Coordination Center
RES	Renewable Energy Sources
SCED	Security-Constrained Economic Dispatch
SCOPF	Security-Constrained Optimal Power Flow
SCUC	Security-Constrained Unit Commitment
SIDC	Single Intraday Coupling
SPP	Southwest Power Pool
TSO	Transmission System Operator
UCED	Unit Commitment and Economic Dispatch
UK	United Kingdom
US	United States
USD	United States Dollars
VER	Variable Energy Resources
VPP	Virtual Power Plant
XBID	Cross-Border Intraday

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1 Introduction

In order to combat **climate change**, the reduction of greenhouse gas emissions is imperative. The economic cost of climate change is estimated to amount to USD 2 trillion by 2050, with a one degree Celsius increase in global temperature [2]. Moreover, the discounted costs of delayed mitigation efforts rose by USD 600 billion in 2020 [3]. The European Union (EU) is committed to increase the share of Renewable Energy Sources (RES) to 32% by 2030 and to achieve carbon neutrality by 2050 [4]. The national energy and climate plan of Germany includes a reduction of carbon emissions by 55% in 2030 (compared to 1990), with RES accounting for 30% of the energy supply (compared to 18% in 2020) [5].

The energy sector's shift from fossil-based systems (e.g., oil, natural gas, and coal) to RES (e.g., wind and solar) is referred to as the **energy transition**. The necessary decarbonization efforts shift central paradigms of electricity markets and thereby shape economic and societal developments. The energy transition provides opportunities to reduce the dependence on scarce fossil fuels and to build an economically and ecologically sustainable future. It is regarded as a key driver for innovation, growth, and modernization of the economy [6]. A successful energy transition is essential to the energy-intensive industry in Germany, in order to keep costs for energy and carbon emissions low, to reliably supply electricity, and to ultimately maintain the economic competitiveness of the industry.

In the past, a few hundred generators in Germany faced largely price-inelastic demand. The latter is a standard assumption in almost all electricity market models [7]. The task of the electricity market was to determine the mix of generators that produce and distribute the electricity at the lowest cost. However, the standard assumption of price-inelastic demand is unlikely to hold in the future. Electricity systems are changing profoundly due to the introduction of large volumes of RES. The largest proportion of RES capacity are Variable Energy Resources (VER) including solar and wind power. The characteristic variability and intermittency of these VER require demand flexibility [8], i.e. demand that can be adjusted or shifted over time. Promoting demand flexibility is a key element in the energy policy of the EU [9]. Similarly, the recent order 2222 by the United States (US) Federal Energy Regulatory Commission (FERC) from October 2020 demands US Independent System Operators (ISOs) to allow for an active demand side and distributed energy resources to bid in wholesale markets.

In short, **demand flexibility is at the core of the energy transition**. This especially holds for Germany with its large energy-intensive industry and, thus, large flexibility potentials. Economically, demand flexibility represents a low-cost option for peak-hour load balancing [10] and a low-carbon ancillary service [11]. Ecologically, demand flexibility is widely considered to be an essential means to reduce carbon emissions and to combat climate change [12, 13, 14]. In particular, there is evidence that demand response fosters the large-scale integration of RES more than other flexibility options (including storage and grid flexibility) [15]. As a consequence, carbon emissions can be reduced effectively by an integrated consideration of RES and demand response [16].

However, the impact of demand flexibility on carbon emissions depends to a great extent on the market framework. For instance, a necessary requirement to achieve carbon reductions are properly defined electricity prices and carbon prices [17]. Moreover, findings from demand response programs in the United Kingdom (UK) show that carbon savings depend on the technological environment and tariff designs [18]. Therefore, **in order to achieve ambitious carbon emission goals, a consistent and enabling market design is required**.

In the SynErgie Whitepaper Electricity Spot Market Design 2030-2050 [1], we discussed the challenges for electricity market design that arise from the energy transition in Germany. Storage, sector coupling, other technological developments, and particularly increasing levels of demand flexibility require a rethinking of market design. A major recommendation from the whitepaper concerned the **move to Locational Marginal Prices (LMPs)** to effectively handle grid congestion and to integrate new types of market participants. Other recommendations referred to technological opportunities, bid languages and pricing rules, as well as strategic implications.

Such a transition does, however, not come without challenges. While the first whitepaper motivated a well-designed transition towards locational prices, this second whitepaper aims at concretizing market design options and at **providing a guideline for implementation**.

In what follows, we first revisit electricity market designs in Europe based on large price zones and the designs used by US ISOs such that this whitepaper is self-contained. We then provide a short outline.

1.1 Exemplary comparison of market design features in Europe and the United States

In order to illustrate examples of different market design features, we focus on a comparison between Europe and the United States. Most of the described features can, however, also be observed in other markets. Still, the study of the US market is interesting for several reasons.

After crises such as the one in California in 2000, electricity markets in the US have undergone reforms, which have been widely reported and studied. There is a vast literature associated to those issues, both in form of research papers and public reports from ISOs. Most importantly, central market design features in the US are different from Europe, which makes the US electricity markets an excellent candidate to compare against.

The fundamental objectives of electricity market designs are the efficient and reliable supply of electricity. This translates into both a short-run welfare-maximizing dispatch and adequate price signals for efficient long-run investments [19, 20, 21]. Other market design objectives include simplicity, transparency, and fairness [22]. In the 1990s, the EU and the US both liberalized electricity markets and both developed different market designs.

US and European electricity markets differ in their bidding formats and market clearing rules. Liberalized **US markets** are centered around an Independent System Operator (ISO), which assumes the role of both market and system operator and thus centrally optimizes the scheduling (allocation plan) and the dispatch (real-time control of resources) [22, 23]. Examples for such ISOs include the California Independent System Operator (CAISO), Electric Reliability Council of Texas (ERCOT), Independent System Operator New England (ISO-NE), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), Pennsylvania-New Jersey-Maryland Interconnection (PJM), and Southwest Power Pool (SPP). After the electricity crisis of California in 2000, many electricity markets in the US have undergone reforms, which have been widely reported and studied. There is a vast literature associated to those issues, both in form of research papers and public reports from the ISOs [24, 25, 26]. Many other countries have adopted a pool model similar to the ones in the US. For instance, several South American countries [27], but also Australia[1] and Canada follow a similar model.[2]

Since 2010, all US ISOs compute separate prices for each node and each time period [29, 30, 31, 32], commonly named LMPs. LMPs at some particular point in the network (aka. nodal prices) measure the marginal cost of delivering an additional unit of electricity to that location. Relevant grid constraints are explicitly accounted for, and hence grid congestion as well as cost of grid losses are efficiently priced. The solution to the clearing problem determines a dispatch that (mostly) renders ex-post congestion management or redispatch unnecessary and sends adequate long-run investment signals for generation and grid capacity [33, 34]. This is especially relevant for the current transformation of electricity systems, in particular the spatial allocation of increasingly decentralized renewable energy capacities [35]. Typically, price differences between nodes in electricity markets are small in the US and arise only if the transmission grid is congested [22]. Pricing in US ISO markets is still changing in an attempt to reduce the weight of uplifts (i.e., individual side payments to resources with negative revenues earned through market prices), and to internalize all operational costs into market prices [32].

In Europe, the historic development from strongly regulated to liberalized markets was similar in different countries, as it was strongly driven by European legislation. **European electricity markets** build on

[1] https://www.energy.gov.au

[2] Much less literature is available about the Chinese market. However, after a large reform in 2015, the electricity market in China moved from a state-owned monopoly to a market-oriented system where both public and private companies participate. The market is based on bilateral contracts and double-sided auctions [28].

the concept of exchange-based zonal markets [22], where system operation is decoupled from market operation. Unlike in the US, market operation is carried out by separate Nominated Electricity Market Operators (NEMOs). A NEMO collects all bids and matches supply and demand. Meanwhile, Transmission System Operators (TSOs) are responsible for ensuring that the balance of supply and demand is fulfilled at every point in time. It is worth noticing that European electricity markets are coupled, meaning that the NEMOs (with input from the TSOs) need to perform a coordinated clearing among different countries [36, 37]. The coordinated clearing is facilitated via the Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA). EUPHEMIA describes a complex allocation and pricing algorithm that has been criticized for its lack of transparency [38, 39]. This is different to the US, where ISOs have a well-defined geographical scope and no plans exist to further integrate the US ISOs [32]. The market coupling in Europe leads to significant computational complexity, which is going to increase as Eastern European markets join the common platform and as we see more participants due to RES.[3]

An important difference to the US ISO markets is the **bid language** used by European NEMOs. The main elements are simple hourly orders (allowing to express price and quantity) and block orders. Regular block orders are buy or sell orders for a period of consecutive hours that can only be accepted in total or not at all. Various versions of these basic formats are available in different NEMOs [32]. The market clearing and pricing is such that there is a uniform price for the entire price zone. Market prices must compensate all accepted bids, and simple bids must be fully accepted if the price is above the generation offer. This is typically not possible with the block bids allowed in NEMOs [40]. As a result, there are welfare losses [41] and paradoxically rejected bids. These are block bids that are profitable at the market prices but still rejected. They are considered “the most relevant concern nowadays in European markets” [32]. The joint response of the Agency for the Cooperation of Energy Regulators (ACER) and the Council of European Energy Regulators to the European Commission’s consultation on a new electricity market design states: “We would particularly like to see clearer rules and greater transparency around the market coupling algorithm (EUPHEMIA)” [38]. The number of block bids is expected to further increase since the bid language does not adequately address the needs of market participants. As a consequence, there is a discussion about the introduction of multi-part bids for different types of participants to replace many block bids submitted now [32]. Moreover, Herrero et al. [32] argue that a welfare-maximizing clearing approach could simplify the clearing algorithm in Europe and help European NEMOs to cope with the increasing complexity.

In the European **zonal electricity markets**, various network nodes are aggregated into larger bidding or pricing zones, requiring uniform (identical) prices within a zone. The design is similar to early US wholesale market designs [42]. Market participants can trade unlimited electricity within a zone, regardless of underlying grid constraints. Since the capacity constraints of the intra-zonal grid are ignored in the trading, frequent and expensive remedial actions by the TSOs are needed in order to mitigate congestion and to maintain operational security. Such measures lead to high costs: in Germany, the TSOs reported redispatch and countertrading costs that went from 41.63 millions EUR in 2011 to over 1 billion EUR in 2019.[4] In the first quarter of 2021, the TSOs in Germany have already reported costs of about 360 million EUR.[5] As participants’ utility or cost functions as well as grid constraints cannot be considered adequately in the trading, the zonal market design currently in place in the EU leads to substantial welfare losses [43, 44].

Example 1 *In Figure 1 we consider a simple 2-nodes example for a single hour. There exists one generator at each node, $G1$ and $G2$, with marginal costs (MC) of 10 EUR/MWh and 20 EUR/MWh, respectively. The line that connects both nodes does not suffer from losses, but it has a maximum capacity of 500 MW. The demand at the nodes 1 and 2 is 100 MWh and 600 MWh, respectively. The efficient solution will be for $G1$ to produce 600 MWh, supplying 100 MWh for node 1 and 500 MWh for node 2. The remaining 100 MWh will be provided by $G2$. The respective LMP will be 10 EUR/MWh for node 1, and 20 EUR/MWh for node 2 (the marginal cost of producing an extra unit). In contrast, zonal pricing would ignore the capacity limit and set a uniform price of 10 EUR/MWh (as $G1$ would satisfy the entire demand). The infeasibility of the dispatch would be resolved by the TSO by means of a redispatch, causing additional costs.*

[3] http://www.nemo-committee.eu
[4] Monitoring Report 2020 at https://www.bundesnetzagentur.de/EN/Areas/Energy
[5] https://transparency.entsoe.eu/dashboard/show

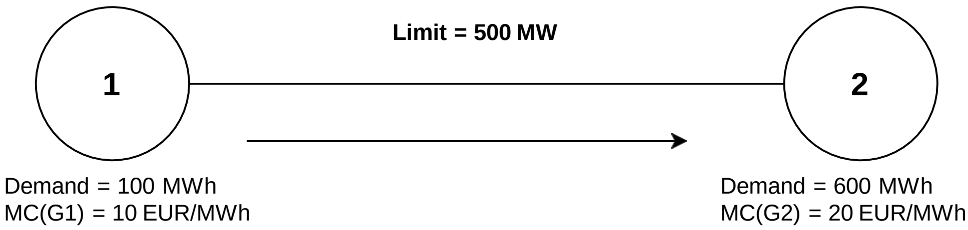

Figure 1: Simplified example of zonal and nodal pricing

Greater short-term intermittent energy supply is likely to require accounting for more transmission and generation operating constraints in European spot markets [42]. Therefore, in our first whitepaper we have argued that a **shift from zonal prices to Locational Marginal Prices** is inevitable in Europe to efficiently deal with grid congestion, and to let new types of market participants take part and be integrated into the electricity market [1]. Overall, LMPs are widely seen as the most economically efficient pricing rule for electricity markets [34]. An increased time and space granularity of prices is further deemed necessary to realize short-term benefits such as incentivizing demand response, avoiding redispatch, or enhancing the flexibility in system operation, as well as long-term benefits such as optimal investments in flexible assets, generation capacity, and grid assets [45]. However, the move to LMPs has significant consequences, not only for the design of spot markets but also for futures markets. This is because there are many nodes with possibly different prices and market participants cannot hedge against a single (zonal) spot market price. As a result, derivatives markets need to be restructured. Besides, setting long-term investment incentives using remuneration mechanisms for capital-intensive RES with very low marginal costs need to be considered.

1.2 Outline

Locational Marginal Prices are central to address the challenges arising from large volumes of RES. However, a transition to LMPs has ample consequences on electricity market design that we will focus on in this whitepaper. Section 2 provides the results of numerical simulations that should help understand the impact of LMPs on welfare and the level of prices in different regions in Germany. In addition, we need to understand the very changes that need to be implemented on the spot market and derivatives markets, in order to facilitate LMPs. This is what we study in Section 3. The vertical, horizontal, and cross-sectoral integration of such markets is discussed in Section 4. With almost zero marginal costs of RES, long-term investment incentives deserve attention, a topic discussed in Section 5. Section 6 analyzes how new technology can facilitate the transition to LMPs, before we introduce complementary policy instruments in Section 7. Finally, Section 8 outlines our vision and policy implications and concludes.

2 A review of numerical studies on LMPs and zonal pricing

In our first whitepaper, we discussed the benefits of LMPs against the background of ongoing decentralization and a shift to low-carbon technologies in the electricity system [1]. To evaluate the impact of a switch to LMPs in Germany, this section provides a **review of literature** that investigates various questions regarding electricity systems under different market designs, in particular the differences between a uniform pricing approach and LMPs. In the reviewed models, the optimization of dispatch, generation capacities, and locational choices in LMP scenarios[6] is performed under consideration of all relevant costs and restrictions for the dispatch. In this case, LMP scenarios maximize welfare and lead to the theoretical first-best outcome, identical to the integrated planner approach [46]. Therefore, the LMP scenarios can be set up as the efficiency benchmark. The presented literature gives insights into efficiency gains, price developments, distributional effects, grid expansion, RES support, and installed generation capacities. Technical details of the presented studies are presented in Table 1.[7]

2.1 Effects of locational price signals

One branch of literature studies **optimal locational investments regarding different technologies**, where LMPs signal profitable investments. For instance, Schmidt et al. [35] and Obermüller [47] study optimal locations for wind power plants and construct an LMP scenario. The locationally resolved prices constitute an additional parameter for the investment decisions next to wind potentials, which is the key investment driver under uniform pricing. Babrowski et al. [48] study the optimal allocation of storage systems, whereas Vom Scheidt et al. [49] study the interdependence of hydrogen production and the transmission grid.

Schmidt et al. [35] find that in Germany, under the LMP scenario, wind energy curtailment drops to one-third of its value under uniform pricing. Assuming the absence of steering RES policies, locations of wind power plants shift from the northwest coast to other areas. However, local price differences are not large enough to see large amounts of investment in wind power in the German south. The authors see weighted average nodal prices increasing by 5 to 10 EUR/MWh compared to uniform prices for consumers in the south.[8] The price increases in most areas are modest, whereas a decrease in the northwest coast is more pronounced with prices decreasing by more than 15 EUR/MWh. Thus, price changes show an unsymmetrical pattern. Similarly, Obermüller [47] finds that under LMPs, revenues of wind power plants at the north coast are lower, even though wind conditions are better. On average, wind power plants' revenues under LMPs are 21% higher than average wind power plants revenues under uniform pricing. However, the variance of revenues is higher due to the consideration of the transmission grid with LMPs.

Babrowski et al. [48] model the German electricity system by 442 network nodes connected by 550 transmission lines and investigate optimal storage system locations. Their model implies a high amount of battery storage units in the northwest coastal area, which smooths high amounts of fluctuating in-feed from offshore wind farms. Additionally, they find high amounts of storage systems in the western region before and after transmission bottlenecks, easing the pressure off the congested grid. The model in the analysis by Vom Scheidt et al. [49] represents the German electricity system by 485 nodes and 663 lines. They aim to investigate optimal hydrogen generation and storage locations, and calculate cost differences under LMPs and uniform pricing. Independent of the scenario, defining which form of hydrogen is considered in the market, the authors find that, in general, prices for hydrogen are lower under LMPs.[9] This is due to lower production costs of hydrogen given lower electricity costs under LMPs. The uniform pricing approach already contains locational investment signals for the placement of electrolyzers, as producers pay the transportation costs of hydrogen. However, LMPs provide a stronger signal for grid-beneficial locations, as the electricity grid is considered for the dispatch. Therefore, locations shift from regions with high hydrogen

[6] Here, the term *scenario* refers to a set of regulatory rules, according to which an electricity system is modeled and assumptions for the location of resources and demand.

[7] Note that not all studies comment on all economic outcomes, as they focus on different topics.

[8] Note that the comparison with uniform pricing includes redispatch costs.

[9] Uniform pricing: 5.98 EUR/kg H2 for compressed hydrogen, 4.30 EUR/kg H2 for liquefied hydrogen, and 4.68 EUR/kg H2 for liquid organic hydrogen carrier. LMPs: 3.55 EUR/kg H2 for compressed hydrogen, 2.73 EUR/kg H2 for liquefied hydrogen, and 3.32 EUR/kg H2 for liquid organic hydrogen carrier.

consumption to regions with high electricity production when moving from uniform pricing to LMPs. Hence, costs of electricity for hydrogen production outweigh transport costs of hydrogen under the LMP scenario. Furthermore, in 2030, electrolyzers increase congestion management costs by 11% in a scenario without locational price signals for electrolyzer placements compared to congestion management costs in 2030 without electrolyzers.[10] Furthermore, congestion management costs are 23% lower (i.e., by 1.46 billion EUR) in a scenario with the same amount of hydrogen in the system but electrolyzer placements driven by locational price signals.

Ambrosius et al. [50] investigate the effects of different market designs on **investment incentives for flexible demand** in the German industry. They construct a multi-stage equilibrium model which allows for endogenous generation capacity investments as well as network expansion. A set of scenarios allows for the comparison of various outcomes under an LMP scenario and uniform pricing.[11] For instance, under an LMP system, one can compare outcomes where flexible demand is either allocated according to the status quo or according to locational investment signals. Note that this constitutes a comparison between two LMP scenarios with the same amount of installed flexible demand. The authors find that welfare increases by 180 million EUR and the expansion of conventional generation capacity is 1,000 MW lower in the scenario with optimal locational investment, as less dispatchable power plants are needed to meet peak demands in certain regions. Also, there is less power line expansion in that scenario. Therefore, both locational investment signals and an efficient dispatch due to locational marginal prices highly contribute to welfare gains. Lastly, in the LMP scenarios, the authors find high average electricity prices in the south (e.g., Bavaria, close to 60 EUR/MWh), which is characterized by excess demand, and lower average prices in the north (e.g., Schleswig-Holstein, close to 50 EUR/MWh), with high amounts of wind power supply and lower demand.

2.2 Congestion management under different market designs

The second branch of literature considers the **impact of LMPs on congestion and grid expansion**. Bertsch et al. [51] and Bertsch et al. [52] study the effect of different market designs on grid congestion and expansion. Again, they do so by running energy system models under different scenarios, representing LMP, multi-zonal, and uniform (single-zonal) pricing in Germany. Bertsch et al. [51] find that congestion management is most expensive under uniform pricing given the additional circumstance that every bidding zone is managed by one TSO. This result is driven by the fact that TSOs of different zones can only agree on the smaller of two proposed levels of cross-zonal line expansion as the project needs agreement of both TSOs. That makes the realization of some lines infeasible. Compared to an LMP system, the scenario with uniform pricing increases system costs by 5%. Bertsch et al. [52] focus on grid expansion. They argue that LMPs reduce the need for grid expansion and reveal locations where it is needed the most. In the scenario with uniform pricing, load shedding becomes necessary at some nodes, as neither sufficient generation capacities nor transmission lines are built at every node due to missing price signals.

2.3 Mitigation of distributional effects

As generation and load structures can highly differ between nodes, there is a strong consensus that a switch to LMPs will have **distributional effects** on participants in the energy system. Some studies mentioned above have pointed out diverging average prices for electricity under LMPs. Therefore, some market participants might oppose such a system change. Financial Transmission Rights (FTRs) are a way to mitigate distributional effects of LMPs.[12]

However, the initial allocation of FTRs is a highly discussed issue, as it again impacts rents of various market participants. Neuhoff et al. [53] estimate distributional effects of different FTR allocation schemes in

[10] This increase holds for both flexibly dispatched electrolyzers and statically dispatched electrolyzers, not reacting to wholesale prices.

[11] In the LMP scenario, one node per federal state in Germany is modeled and one node per neighboring country.

[12] An FTR determines the obligation or option to pay or receive payment, when congestion occurs on a line, depending on the direction of the congestion. The value of the FTR is defined by price differences between the nodes at both ends of the congested lines. See subsection 3.2 for a discussion of FTR.

Germany.[13] They find that FTRs are very effective in mitigating distributional effects of LMPs. However, the tested schemes have different income effects on participants, as, for example, RES and conventional power plants have different cost functions. The authors conclude that more complex FTR allocation schemes might be needed for the initial allocation of FTRs to set the right incentives for all market participants at all times, when switching from uniform pricing to an LMP system.

2.4 Remarks on numerical studies on LMPs and zonal pricing

After reviewing the literature, it should be clarified what the reviewed studies can and what they cannot contribute to understanding the effects of switching to LMPs. Studies typically abstract from various aspects to effectively represent a complex system within a model [54]. In electricity system modeling (especially regarding the comparison of LMPs and uniform pricing), it is particularly those **abstractions and simplifications** which are being discussed as hindering factors for a switch to an LMP system [55]. For instance, in our first whitepaper, political costs and system transition costs were discussed in more detail, as well as the perception that less competition at each node may increase market power. We argued that increased competition with market participants across the entire grid due to a price-responsive allocation of transmission capacity outweighs the concern of increasing market power under LMPs [1]. However, when abstracting from these issues, LMP systems unanimously represent the efficiency benchmark for electricity systems, both for the short-term dispatch and long-term investments. Therefore, the numerical results of the reviewed studies, comparing scenarios of LMPs, zonal pricing, and uniform pricing, can be viewed as an indication of how LMPs will affect various economic outcomes at hand, keeping in mind that some other relevant questions cannot be answered comprehensively by existing numerical models. Further, it needs to be studied whether price signals from LMPs are strong enough to drive grid-serving capital investment or whether they 'merely' offer additional evidence to inform and support regulatory determined grid expansion choices, as there seems to be evidence from US markets as well as analytical models that capacity, load, and grid expansion do not necessarily follow price signals in the long term [56, 57].[14]

Moreover, especially in the European case, the possibility to allocate capital where it is most grid-serving is increasingly constrained by barriers like a lack of comprehensive and stable regulation as well as a lack of public acceptance, with lengthy and complex approval processes [58, 59]. Therefore, investments for grid expansions need an adequate lead time in order to be already in place when switching to LMPs. This lead time should be used by market participants to already anticipate transmission capacities and potential price signals in order to plan their own investments adequately. For these reasons, numerical simulation models could and should be further refined to allow for an accurate anticipation of the future market outcomes under LMPs regime. Moreover, the results of these numerical simulation models can and should drive the discussion on whether, for example, the political costs are reasonable to undertake a system transition towards LMPs. Furthermore, concerns regarding a switch to LMPs are well known and researched in markets that implemented LMPs, and therefore instruments to mitigate these problems exist.[15]

There is a strong consensus in the literature that a switch to LMPs increases welfare. The following main results sum up the findings:

- LMPs support the efficient dispatch of generation and capacities through direct consideration of generation, load, and transmission capacities at each node.
- LMPs generate efficient locational price signals for long-term capital investment.
- Larger price differences are only short-term since capital allocation reduces larger price differences between nodes and regions in the long-term.

[13] The FTR allocation to generators can be either based on historical generation (volume-based) or based on installed generation capacities (capacity-based). The FTR allocation to the demand side is based on consumption.

[14] Note that an LMP system does not exclude the possibility of further locational price signals in the form of policy instruments, further increasing the incentive to allocate capital where it is most grid-serving.

[15] See for example Harvey and Hogan [60] for a discussion of market power under nodal and zonal congestion management.

> Still, as necessary grid expansion projects are increasingly impeded in some European countries, an appropriate lead time before the LMP introduction might be necessary to account for the long time periods until new infrastructures are built up.

Lastly, as noted above, some aspects of LMPs have not been included in quantitative electricity system modeling yet. However, when aiming to explicitly address the effects of switching to LMPs, rather than setting up an LMP scenario as a benchmark for numerical analysis, further research could expand the existing body of literature by incorporating these issues.

Author	Focus	Number of nodes	Endogenous transmission line expansion	Time frame	Resolution	Region
Ambrosius et al.[50]	Flexibilization of industrial electricity consumption	28	yes	2035	Hourly resolution: first week of every month (2016h)	Germany plus 12 nodes for neighboring countries
Obermüller[47]	Wind power plant allocation	575	no	2014	Hourly resolution (8760h)	Germany plus 9 additional nodes, one per neighboring country
Babrowski et al.[48]	Electricity storage systems	440	no: exogenous grid expansion according to power grid extension act EnLAG 2009.	2020-2040 (every fifth year modeled)	Hourly resolution: 12 representative days per year (288h)	Germany
Schmidt et al.[35]	Wind power plant allocation	380	no: exogenous grid expansion according to German grid development plan 2019.	2019,2020, 2025, 2030	Hourly resolution: 12 representative days per year (288h)	Germany plus 8 neighboring country nodes
Bertsch et al.[51]	Grid expansion	70	yes	2020 and 2030	Hourly resolution: 9 representative days per year (216h)	Nodal representation of Central Western Europe and aggregated representation of other European regions.
Bertsch et al.[52]	Congestion management design	70	yes	2020 and 2030	Hourly resolution: 9 representative days per year (216h)	Nodal representation of Central Western Europe and aggregated representation of other Europen regions.
Kunz et al.[53]	Financial transmission rights (FTR) allocation	438	no	2012	Hourly resolution: 3 representative weeks per year (504h)	Germany plus 22 nodes for neighboring countries
Vom Scheidt et al.[49]	Interdependency hydrogen and electricity system	485	no: exogenous grid expansions according to German Federal Network Agency.	2030	Hourly resolution (8760h)	Germany and one node for imports of hydrogen

Table 1: Overview of LMP studies

3 Perspectives for spot and derivatives markets in an LMP system

An implementation of an LMP system as a main feature for European electricity markets 2030–2050 would invoke changes to the structure and functioning of different markets. In this section, we first elaborate on spot markets before we analyze the impact on derivatives markets.

3.1 Spot markets

As outlined in the introduction, the market micro-structures in zonal European electricity markets and in US ISO markets with locational marginal prices differ significantly. We will first discuss the changes in the spot market organization required in Europe with nodal prices, before we introduce the welfare maximization problem that has to be solved, as well as the arising pricing problem.

3.1.1 Market organization

Under current European market design, it can broadly be distinguished between day-ahead, intraday, and balancing markets, which together determine the dispatch of all participating resources.

The preliminary economic allocation of electricity is determined in **day-ahead and intraday markets**. In the day-ahead market, the NEMOs collect all electricity bids for the following day. For all coupled markets, the EUPHEMIA algorithm then matches supply and demand, and determines zonal day-ahead electricity prices (limited to the range between -500 EUR/MWh and 3,000 EUR/MWh) under consideration of cross-zonal interconnector capacities. Subsequently, an intraday market, consisting of an opening auction and a continuous trading period, allows for adjustments in production and consumption based on more accurate forecasts. The initial auction sets prices ranging from -3,000 EUR/MWh to 3,000 EUR/MWh, while the continuous trading follows pay-as-bid rules. As the underlying zonal model neglects transmission limits within each zone, the obtained dispatch might not be physically feasible. In the introduction, we have already discussed the rising costs for the resulting redispatch and feed-in management by the TSOs. Such measures eventually determine the physically feasible and final dispatch of electricity.

In US ISOs that already use LMPs, short-term markets comprise the day-ahead and the real-time market. The real-time market features a bid-based, security-constrained economic dispatch and is conducted every five minutes throughout the day [22]. It balances the differences between day-ahead commitments and the actual real-time demand and production of electricity. In these markets, grid constraints and power flows between all nodes are explicitly considered, significantly reducing ex-post congestion management or redispatch. Imbalances are settled on real-time markets, and only so-called ancillary services are required to maintain grid stability and security in the short run.

With the exception of the ERCOT real-time market, these ancillary services are co-optimized along with the energy itself in both day-ahead and real-time markets. Both markets consider online (spinning) and offline (non-spinning) resources, but the day-ahead market typically allows for longer response times (e.g., 30 minutes) compared to real-time reserves (e.g., 10 minutes). The joint optimization replaced the previous sequential optimization which was considered too inflexible, insufficiently aligned with the energy dispatch, and unable to globally minimize the total cost of energy and reserves [61]. In contrast, the co-optimization adds some computational complexity but accounts for opportunity costs and enhances welfare and market price signals. For instance, after the introduction of the co-optimization in California, ancillary service costs decreased from 13% of annual energy costs in 1998 to only 1.7% in 2019 [62]. Despite institutional challenges [63], a co-optimization of energy and reserves in European markets could decrease the overall costs significantly and appropriately reflect opportunity costs [64]. Furthermore, under a system with co-optimization, well-defined operating reserve demand curves can account for the real value of reserves more accurately [63].

An implementation of LMP systems in Europe would put a greater **emphasis on real-time or intraday markets**. Redispatch or mandatory wind and solar spills could largely be avoided. Moreover, the dilemma between a cost-based and a market-based redispatch, the former not being applicable to many future market participants and the latter resulting in the infamous Inc-Dec gaming[16], would be resolved. Balancing energy, which is currently traded in a separate market, will become a key component of a real-time market under LMPs, implying a significant shift of market structures and responsibilities [65]. Several options to implement a real-time market in Europe are possible, for example, to implement two-settlement markets like the market structure in the US or to improve existing markets to make balancing markets the reference [34]. Moreover, the current balancing group responsibility requires a balance of physical generation and consumption. This is hard to maintain for a small balancing group, e.g., consisting of only a single generation unit. The physical balancing responsibility therefore favors larger portfolios [66, 67] and limits liquidity in balancing markets [66, 68]. In contrast, shifting to financial balancing responsibility (comparable to single balance pricing without additive components) enables unit-based (or nodal) balancing, increases the transparency of expected power flows, and can contribute to system stability [69, 67].

As the transformation to LMPs affects both the market and the network, this also implies **institutional changes** in the corresponding responsibilities and roles of the involved entities. Enforced by the EU 3rd Energy Package in 2009, the unbundling of former vertically integrated utilities formed the current system with TSOs, owning and operating the network, and NEMOs, operating the market platform. Furthermore, in Europe we observe the trend towards stronger coordination on system operation level by the introduction of European Regional Coordination Centers (RCCs). These roles will need to be revisited during a transition to LMPs as the tasks will shift by merging the operation of the network and the market.

During the liberalization in the 1990s, the degree of unbundling has been intensively discussed and, in the US, the concept of an Independent System Operator (ISO) has been established. The ISO is the responsible entity for the operation of the short-term markets and the network operation, but the ISO neither owns the network nor any generation unit. This model is different from the current TSO model, which is dominantly deployed in Europe, and in which responsibilities related to network planning, asset construction, and system operation are in one hand. Bundling the tasks of an ISO at the European TSOs may rise concerns regarding the incentive to optimize congestion rents as the TSO simultaneously owns the network [70]. In particular, with lumpy transmission investments, the ownership of the network assets can influence the TSO's decisions on optimal power flows and congestion management [71]. However, if a proper regulation of the TSO is in place, it can be manageable to combine both tasks at the TSO [72]. By now, the question of which institutional system to prefer for the operation of LMPs remains open, as there is no clear recommendation in existing literature [73]. It is open to debate which of the existing entities in the EU would become in charge or whether a new responsible party has to be defined [34]. The existing separation of the transmission network, the electricity market, and strong regulatory authorities in the EU may provide a good starting point to solve the institutional issues [74].

However, despite a zonal market design, the UK decided to move towards an ISO type of institutional setup and to legally split the TSO National Grid into an asset-owning part and into a system operation part in 2019. Recently, the UK ministries and regulator even proposed to go one step further by establishing a so-called Future System Operator (FSO).[17] The case of Poland provides an example vice versa. Despite the proceeding implementation of a nodal market design, it is to our knowledge not planned to change the governance structure of the national TSO towards an ISO-like company. And lastly, the discussion around the governance structure for offshore wind in Europe provides a third example: With an expected massive increase of offshore wind capacity and the tendency towards a development of a meshed offshore grid, new challenges arise with respect to governance in such complex structures. Some stakeholders call for an establishment of an "ISO" who would be responsible for the new offshore bidding zones.

Based on these cases, we argue as follows and recommend:

> Firstly, that the discussion and choice of a certain market design can and should be detached from the questions related to the institutional arrangements. Although there might exist some interdependencies between market design and governance, this should not be a barrier for a (political) decision on certain market evolutions.

[16] Incentives for participants to change their consumption and generation behavior to aggravate congestion and to profit from price differences between consecutive energy markets

[17] https://www.current-news.co.uk and https://www.gov.uk

> Secondly, that black-and-white discussions on the establishment of "the ISO" are not adequate. It seems to be conceivable that there are several options to address a potential governance issue as for instance, solutions where most of the functions of current TSOs remain with them and real-time calculations are done on a decentralized basis (individual TSOs perform calculations in parallel using merged datasets) or integrated in already existing European RCCs.

Further aspects of the institutional design are related to market monitoring, in particular if ex-ante monitoring is implemented and controlling bids to avoid market power abuse [75], and to the cooperation and coordination of TSO and Distribution System Operator (DSO) activities and the corresponding market design at the distributional level [34]. These aspects are discussed in Sections 4 and 5.

3.1.2 Efficient dispatch and optimal power flow

Computational questions play a central role on electricity markets. Already with the zonal system in Europe computational complexity is a major concern. The EUPHEMIA algorithm aims to solve a very large optimization problem and clears the European market. While it does not consider transmission constraints within zones, it has become a very complex algorithm that determines trade and prices. **Computational complexity** can be expected to increase significantly with a large number of renewable energy sources.[18]

In US ISO markets systems, the market operator centrally solves large welfare maximization problems in both the day-ahead and the real-time context. Then prices are determined based on the welfare-maximizing dispatch. Questions concerning pricing and the distribution of rents are separated from the efficient market clearing which ensures overall maximum welfare. In the **day-ahead market**, an initial Security-Constrained Unit Commitment (SCUC) problem determines which resources are committed for the upcoming day. This is followed by a Security-Constrained Economic Dispatch (SCED) which determines the operating level of every committed resource. Subsequently, the market operator determines prices at each node to reflect the locational value of electricity and to send proper investment signals for generation resources, transmission capacity, or demand flexibility. The day-ahead market typically considers hourly dispatch intervals.

In contrast, in the **real-time market**, the SCED and pricing is typically conducted in five minute intervals to determine the real time prices to guide generation and demand, which may in the case of large generation assets be accompanied with dispatch signals [22]. Earlier approaches to use five minute dispatch intervals together with averaged hourly prices have been found inefficient [63]. Real-time markets typically also include additional SCUC runs for resources with short start-up times. While dispatch instructions are only issued for the next five minutes, the real-time market clearing looks ahead over a longer interval, depending on the ISO. For instance, whereas CAISO optimizes through at least the next trading hour [77], PJM only looks ten minutes beyond the target time [78], and ERCOT optimizes only over the five minute interval under consideration [79]. This has an impact on resources with inter-temporal constraints and longer time horizons (e.g., storage) as well as prices, and the look-ahead interval should therefore be designed in accordance with the characteristics of participating resources and desired policy incentives.

To give a representative example, the CAISO [80, 81] day-ahead markets consider hourly time intervals. The so-called integrated forward market performs the initial hourly unit commitment (SCUC) and economic dispatch (SCED), and delivers hourly day-ahead LMP. In the real-time market, bids refer to sub-hourly time intervals, and therefore long-start units cannot effectively participate. Moreover, unlike in the day-ahead market, demand bids are no longer accepted, since CAISO postulates its own demand levels that need to be cleared. Real-time unit commitments (SCUC) run four times per hour with different time horizons to produce resource commitments in 15-minute intervals. Each real-time unit commitment includes an SCED run for a single 15-minute interval. Therefore, economic dispatches are computed for every 15-minute interval in a rolling fashion over time. This is referred to as the fifteen minute market. The fifteen minute market also includes a pricing run for 15-minute LMP. Finally, the real-time economic dispatch as an SCED

[18] ACER and the Council of European Energy Regulators [38] responded to the European Commission's Consultation on a new Energy Market Design and stated: "We would particularly like to see clearer rules and greater transparency around the market coupling algorithm (EUPHEMIA)". The public documentation of the market-coupling algorithm [76] is not completely detailed. Relaxing the uniform price requirement is seen as one way to address the computational complexity issues in EUPHEMIA.

is calculated every five minutes and approximately 7.5 minutes before the actual dispatch. It produces the dispatch instructions and five-minute LMP.

US ISO markets use so-called **multi-settlement** systems. This means that the cleared day-ahead dispatch and day-ahead prices form the basis for resource compensations. Any deviations in the real-time clearing are settled with the respective real-time price. Among other things, this enables virtual bidding, i.e., submitting purely financial bids that are closed prior to the physical delivery, and an enhancement of market performance through financial participants [82].

Real-time markets could be further augmented by additional **intraday auctions** to pool bids and offers and increase liquidity [83]. Depending on design goals and the look-ahead interval, intraday auctions could be designed as either SCUCs or SCEDs. In the latter case, they would send additional reference price signals. The lack of transparent intraday prices has been identified as an area of improvement for multi-settlement US ISO markets [84]. Moreover, there is evidence that intraday auctions enable a more efficient use of cross-border capacities in the European context compared to continuous bilateral trading [85]. Finally, they ensure a secure market operation, incentivize competitive and easier bidding strategies, and potentially contribute to unlocking flexibility [64]. It has recently been concluded that the key question is not whether intraday auctions are needed for European markets, but rather how many of them are appropriate [85].

Both SCUC and SCED problems respect constraints associated to the transmission grid. This class of problems is thus also referred to as **Optimal Power Flow (OPF) problems**. Below, we briefly outline the main objective and constraints of OPF models in an informal manner (e.g., ignoring ancillary services, market coupling, sector coupling, or DSO integration). The OPF ensures a welfare-maximizing allocation of electricity, determining both the optimal dispatch of resources and corresponding power flows through the transmission grid.

$\max$	Social Welfare: Buyers' valuations $-$ Generators' costs	(OPF)	Objective
subject to			
	Generators' operating conditions		Economic Dispatch
	– *List not exhaustive* –		
	Minimum and maximum generation	(1)	
	Minimum run time, start-up restrictions	(2)	
	Ramping limits	(3)	
	Buyers' preferences		
	– *List not exhaustive* –		
	Price-inelastic load	(4)	
	Flexible loads	(5)	
	Grid representation		Power Flows
	– *List mutually exclusive* –		
	AC power flow *(ACOPF)*: active & reactive power flows, line resistances & reactances, voltage angles, voltage magnitudes	(6a)	
	DC power flow *(DCOPF)*: active power flows, line reactances, fixed voltage magnitudes	(6b)	
	Other convex relaxation of AC power flow (e.g. SDP, SOC, QC)	(6c)	
	Nodal power balance	(7)	
	Line flow limits	(8)	
	Contingency constraints	(9)	

The OPF is based on the submitted bids and takes into account the generators' costs and operating conditions (1-3), typically including minimum and maximum power generation, ramping restrictions, or minimum runtimes after a generator's start-up. It also considers buyers' valuations and constraints expressing buyers' preferences and flexibilities (4-5), which are of increasing relevance due to the rising share of price-responsive and dispatchable demand. In order to be feasible, the dispatch must also satisfy physical constraints of the power grid. Various representations of the transmission network (6a-6c) are discussed below. Moreover, at each node the net total of demand, supply, and power flows needs to be strictly balanced (7) and the flow limits of transmission lines must not be violated (8). The OPF problem can also include additional contingency constraints to consider unexpected events and outages, often referred to as Security-Constrained Optimal Power Flow (SCOPF) [86].

Note that SCUC and SCED can be regarded as different variants of the OPF problem. The SCUC typically does not account for certain operating conditions (e.g., ramping limits). In contrast, the commitment of resources and other discrete variables in the SCED are fixed, which allows to solve the problem faster and in shorter intervals.

The representation of the market clearing in the central OPF problem depends on the **bid language** provided for the market participants. As discussed in our first whitepaper [1], a bid language should enable efficient outcomes by allowing market participants to express economical preferences (including opportunity costs), or physical constraints [87]. There is evidence that the current bid language under EUPHEMIA, mainly consisting of single-part bids and block orders, is not sustainable with an increasing penetration of RES [32]. The increasing variability and uncertainty of energy supply increases the number of block bids and results in computational challenges. Moreover, the current bid language is not well suited for new types of market participants (e.g., storage or flexible demand), and the widely used portfolio bidding gives advantages to incumbents as opposed to new entrants [32]. Embedded in an LMP system, a scalable bid language consisting of multi-part bids and tailored, resource-specific parameters would handle uncertainties on electricity markets more efficiently, increase the transparency of the clearing algorithm, and alleviate the computational complexity [32, 63, 88, 89].

With respect to the **network representation** (6a-6c), the Alternating Current Optimal Power Flow (ACOPF) model is the theoretically ideal approach as it correctly models the underlying physics [86]. It includes a set of non-linear constraints, describing the energy flow through each transmission line [90]. Considering various integer variables required in the OPF, the ACOPF turns out to be a non-convex non-linear mixed-integer optimization problem [91]. In spite of advances in global optimization, the ACOPF can be regarded intractable for practical problem sizes. To put this into perspective, the CAISO operating region covers 26,000 circuit miles, roughly 1,000 power plants, a population of 30 million, and about 9,700 pricing nodes [92]. Solving ACOPF problems of that size is out of reach for state-of-the-art techniques in global optimization, and there are currently no tools that employ the full ACOPF without relaxations.

This led to significant research into convex relaxations of the ACOPF [91]. The linear relaxation of the AC power flow equations is referred to as the Direct Current Optimal Power Flow (DCOPF) model. It does not model all the line resistances, or reactive power flows. Nevertheless, it is used among US ISOs to compute the efficient dispatch and prices in a network [93]. The fact that such linear relaxations of the ACOPF can be solved today hinges on the remarkable performance increases in mixed-integer linear programming over the past 30 years [94, 95]. For instance, PJM has initially introduced mixed integer programming to solve a DCOPF in 2005 [96]. This led to improved market outcomes and substantial cost savings compared to the previously used Lagrangian relaxation method [86], and has consequently been adopted by all other ISOs.

The problem continues to be a computational challenge: New bidding formats add to the complexity of the problem, but in particular the energy transition leads to many more and smaller generators, which leads to high computational costs and eventually to intractability of the problem. Already the DCOPF implementations in use today often result in solutions that must be iteratively checked for physical feasibility before implementation [97]. As noted by the FERC, the resulting adjustments also lead to higher and more concentrated uplift payments, distorting the market price signal [98]. Therefore, the development of solution methods providing physically feasible and tight solutions within the time limits required for practical application remains an open problem [99, 100, 101, 102, 103, 104]. Promising convex relaxations include the Semi-Definite Programming (SDP) relaxation [105, 106], the Second-Order Cone (SOC) [107], the Convex-DistFlow (CDF) [108], the Quadratic Convex (QC) relaxation [109], and Moment-Based [110] approaches. Distributed and parallelizable OPF algorithms provide another way forward to incorporate large numbers of distributed energy resources [111]. Moreover, there are increasing efforts to incorporate and optimize the use of power flow control instruments, such as phase shifting transformers or switched shunts. The ARPA-e grid optimization competition[19] in 2020/21, awarded with $2.3 million, emphasizes the relevance of

[19] https://gocompetition.energy.gov/

this research.

An LMP system in Europe requires an adequate incorporation of grid constraints into spot market clearing problems. Currently employed relaxations of power flow models, such as DCOPFs, would already imply higher welfare and gains from lower redispatch levels [34, 112]. In addition, ongoing advances in power flow optimization could be leveraged and promoted to generate reliable and physically feasible dispatches.

3.1.3 Pricing rules

Regardless of the choice of the power flow model, the inherent non-convexities of the OPF lead to challenges in pricing. The umbrella term of Locational Marginal Prices typically refers to the concept of locational prices, but leaves open the specific mechanism to arrive at such prices. As discussed, modern electricity markets are two-sided non-convex markets, causing several trade-offs for the price determination.

Ideally, market operators could compute **Walrasian prices** on electricity spot markets. Walrasian prices describe linear (single price for each good or hour of the day) and anonymous (prices being independent of the bidder) competitive equilibrium prices. At such prices every participant maximizes payoff and the budget is balanced. This means the market does not require a subsidy and the outcome is stable. Under certain assumptions, including convex preferences and perfect competition, the Arrow-Debreu model shows the existence of Walrasian prices [113, 114, 115, 116]. If Walrasian prices exist, then any Walrasian equilibrium implies a Pareto efficient allocation of the goods and any efficient allocation can be attained by some set of Walrasian equilibrium prices [117]. Unfortunately, these assumptions are not satisfied in non-convex electricity markets. A number of recent papers discuss the very assumptions under which a Walrasian equilibrium exists [118, 119, 120, 121, 122]. Market operators might need to relax the linearity or anonymity of the price function, in order to achieve a competitive equilibrium. However, it can be shown that with general preferences even non-linear and personalized competitive equilibrium prices might not exist in two-sided (electricity) markets [40].

As a consequence, several pricing rules have been developed to mimic such equilibrium prices on non-convex electricity markets [7]. For instance, nowadays many practical implementations of LMP rules are based on **Integer Programming (IP) pricing**, where prices on a node in the transmission grid are set to the dual of the nodal power balance constraints (7) of the linear program resulting from fixing the integer variables of the DCOPF to their optimal values. IP prices are linear and anonymous, yet do not constitute a competitive equilibrium. This is because participants are not maximizing payoff at these prices. Prices are often not even individually rational, meaning some market participants incur losses when payments are limited to price compensations [123]. Some ISOs recently switched to **Extended Locational Marginal Prices (ELMPs)** where prices are derived from the duals of the Linear Progamming (LP) relaxation of the DCOPF, but similar issues arise [124].

In order to avoid losses, ISOs introduce **personalized side payments** to either incentivize all market participants (lost opportunity cost payments) or only to ensure individual rationality (make-whole payments) [125]. The latter form of payment is mostly used by ISOs, since stability can be achieved differently in the highly regulated environment of electricity markets. Actually, most ISOs stipulate penalties for deviating from the optimal dispatch [126]. Under either form of compensation, the payments to the market participants are now personalized and non-linear, despite the linear and anonymous market prices.

However, even make-whole payments have recently come under scrutiny [126]. The US FERC as the relevant supervisory authority found these practices to be unjust and not accurately reflecting the cost of serving load [127]. As these side payments are not reflected in the public price signal, investment signals and references for hedging markets are distorted. Therefore, the FERC has released several orders saying that “the use of side-payments can undermine the market’s ability to send actionable price signals”[20]. Similarly, [127] point out that “the make-whole payments are not transparent to other market participants and are allocated too broadly to provide correct price incentives for market participants to make efficient entry and exit decisions as well as efficient investments in facilities and equipment”. The authors suggest the so-called Average Incremental Cost (AIC) pricing that avoids make-whole payments through prices that also

[20] https://www.ferc.gov

recover fixed cost components. However, in order to ensure efficiency, AIC pricing requires personalized prices on the demand side [127]. AIC pricing therefore implies a different kind of discriminatory pricing, where the degree of price differentiation remains to be investigated in settings with considerable demand bidding.

The following example illustrates pricing with convex (a) and non-convex (b,c) preferences and the resulting trade-offs.

Example 2 *Consider Figure 2 with one generator G1 and two consumers D1 and D2 at a single node and in a single hour.*

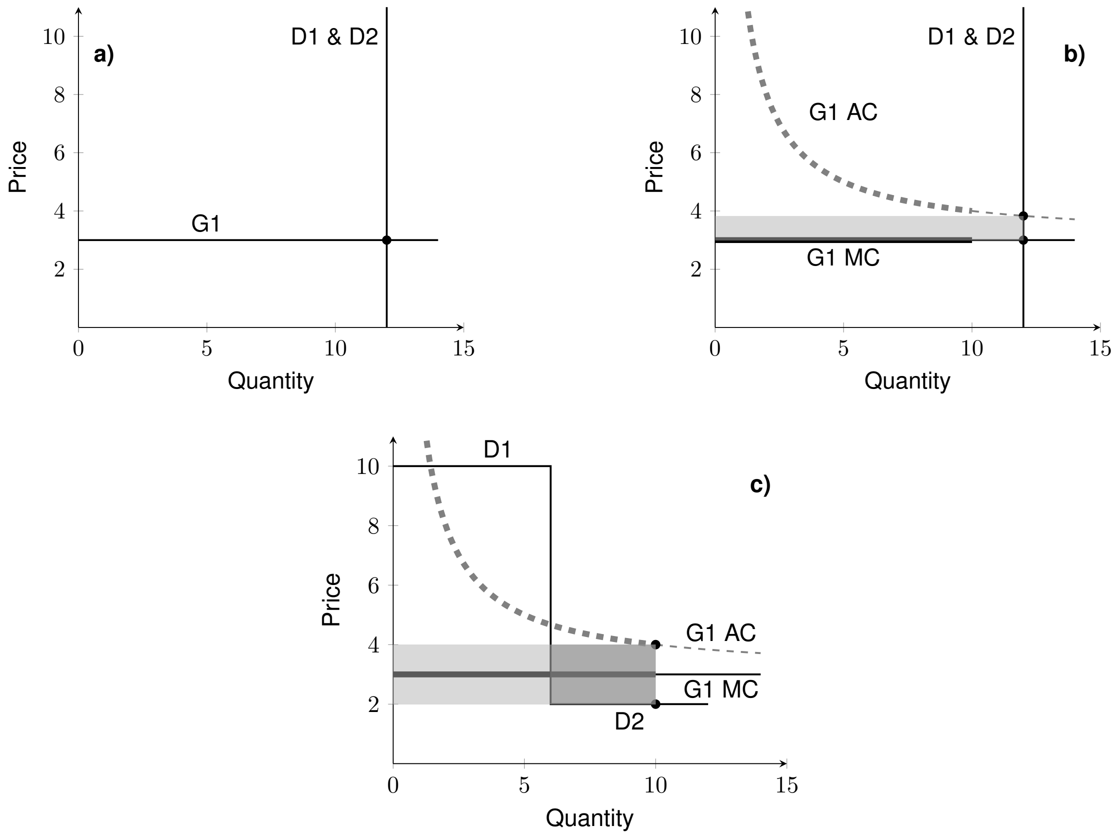

Figure 2: Prices and make-whole payments under different scenarios

- *In case (a) G1 is able to produce up to 14 MWh at constant marginal costs of 3 EUR/MWh. D1 and D2 ask for 6 MWh each. Setting the price at 3 EUR/MWh is, in fact, a Walrasian equilibrium and requires no make-whole payments. No non-convexities occur in this case.*
- *In case (b) G1 has a minimum load of 10 MWh. This part of the offer curve is drawn as a thick line. When the generator is online (i.e., producing at least the minimum load), fixed costs of 10 EUR occur regardless of the produced quantity. This leads to average costs (AC) higher than the marginal costs (MC). Using the IP price of 3 EUR/MWh would require a make-whole payment of 10 EUR to G1 in order to recover the fixed costs (marked as gray area between marginal and average costs). Using a different pricing rule, e.g., the AIC price at 3.83 EUR/MWh, would render make-whole payments unnecessary.*
- *Finally, case (c) considers a price-sensitive demand side. In particular, D1 is willing to pay 10 EUR/MWh for 6 MWh, while D2 is only willing to pay 2 EUR/MWh for 6 MWh. The optimal schedule is*

to clear the minimum load of 10 MWh of G1, assigning 6 MWh to D1 and 4 MWh to D2. In this case, there is no linear and anonymous market price that requires no make-whole payments. For example, setting the price at the marginal cost of 2 EUR/MWh leaves G1 with a loss of 20 EUR (marked in light gray). Similarly, setting the price at the average generation cost of 4 EUR/MWh leaves D2 with a loss of 8 EUR (marked in dark gray). Indeed, the only way to avoid make-whole payments is to resort to discriminatory pricing.

Therefore, while LMPs are desirable as they set better regional investment signals, there is an ongoing discussion regarding the specific properties such prices should achieve. The complexity of electricity markets does not allow for idealized Walrasian equilibria, and **several trade-offs** need to be weighted. Experiences from practice and findings from research should be leveraged to design a proper locational pricing scheme.

Compared to the current European spot market organization where day-ahead markets are central, in US ISO markets the real-time markets is of greater importance. However, the decision on LMP or zonal prices is independent of the time frame and nodal prices can also be implemented on the European day-ahead and intraday markets requiring minimal institutional changes. We argue that institutional arrangements and governance structures deserve a debate on their own.

Computing an efficient dispatch in any of these markets is a complex undertaking itself and depends on appropriate bidding formats and network representations. Multi-part bids and resource-specific bidding formats would contribute to a more accurate and effective expression of economical preferences. We also outline how advances in optimization algorithms promise more accurate network models to enhance efficiency.

From the efficient dispatch, locational prices can be computed in various ways, and each pricing scheme comes with certain trade-offs that need discussion. Non-convexities in the OPF problem prevent the existence of Walrasian equlibrium prices and even imply personalized side-payments to compensate market participants for individual losses. Therefore, pricing schemes need to balance several trade-offs, and the design of the specific LMP algorithm needs to be closely aligned with underlying policy objectives. Under an LMP system, the current European market design could be augmented by the introduction of additional intraday auctions. This would provide transparent price signals, increase liquidity, and enable a more efficient use of cross-border capacities.

3.2 Derivatives markets

A well-functioning derivatives or forward and futures market allows market participants to trade not just the actual commodity – electricity – but the expected price of it [128]. By doing so, short-term volatility on the physical spot markets caused by load, season, weather, and short-term fluctuations of fuel and emission prices can be anticipated and financial risk exposure can be hedged, while incentives to respond to the spot prices are retained.

In Europe, most of the end-consumer prices are defined by the expected annual average price traded on derivatives markets. Notable exchanges offering derivatives for electricity are the European Energy Exchange (Europe), Nodal Exchange (US), or NASDAQ Commodities (Europe/Nordics). The offered contracts are typically cash-settled futures contracts, which are revalued every day (mark-to-market) such that only price differences over time are settled. The underlying[21] is the actual electricity price of the zone, node, or hub. Some exchanges also offer options on futures contracts. The most liquid contracts are front-year contracts, i.e., averaged over the next calendar year. Usually, exchanges also offer up to six or even ten years on the long end as well as quarter, month, week, and even day contracts on the short end for traders to hedge against seasonality and short-term corrections of economic expectations – but liquid trade is limited to the first three to four years. As the contracts do not contain physical delivery but are financially settled, trading on the derivatives markets allows non-physical counterparties[22] to contribute liquidity and, once a contract has sufficient liquidity, it can attract traders from other market areas, such as neighboring countries. For market participants from other markets there is always a trade-off to be considered: On the one hand, using a contract with reference price in a neighboring zone involves a basis risk because the traded contract does not exactly match the actual price exposure. On the other hand, using contracts from the neighboring zone traded at larger liquidity reduces transaction costs and allows market participants to trade the volume they want to buy or sell at their expected price. The attraction of participants from different market areas to contracts with high liquidity shows that traders can manage basis risk and prefer to bear this risk if it allows them to reduce transaction costs from illiquid markets.

3.2.1 Derivatives in zonal markets

Trading derivatives is particularly attractive on zonal electricity markets. As there is only one underlying per market area (usually defined by national borders), only one family of contracts has to be traded even for large generation and consumption portfolios. The market reached with one contract can be quite large, thus **pooling liquidity and reducing transaction cost** for traders to the efficient limit. Against this background, generators and consumers can hedge their exposure practically free from basis risk and at minimal transaction cost, because the underlying of the liquid derivative is the actual electricity prices they are exposed to.

This setup also allows the construction of contracts with **physical delivery of derivative contracts** that are traded on financial markets. Such contracts are attractive for smaller market participants because this allows them to qualify for an exemption from financial regulation of financial instruments as, e.g., in the European Markets in Financial Instruments Derivative II (MiFID II) directive[23].

Market areas with excellent liquidity also support **large churn rates**, i.e., the ratio of financial trading volume to physical generation/consumption. In Germany, the churn rate is of the order of 12, in the Nordic markets, it is 4 to 5 [129, Fig. 17]. This high turnover reflects two important aspects of derivatives trading: Positions are adjusted with high frequency to accurately manage spot market risk, and actual hedging strategies can be quite sophisticated, e.g., modeling physical assets as real options combined in a risk-neutral portfolio with the derivative. This allows to manage not just price risk, but also activation risk for flexible assets and requires the possibility to decouple traded volume from nominal asset capacity.

[21] The "underlying" or reference price of a derivatives contract is the physical or financial asset from which the derivatives contract is derived and according to which its final value is calculated. For instance, a futures contract on German Bonds uses the value of the German Bond as underlying. The "derivative"-aspect of the contract is the agreement that delivery of the value is postponed to a certain date in the future.

[22] Non-physical counterparties are usually brokers, insurances, and hedge funds.

[23] Legislative framework by the European Union to regulate financial markets and improve investor protection.

3.2.2 Derivatives in LMP markets

If the underlying spot market is nodal, the fundamental design of derivatives markets need not change. However, due to the bidding zones being reduced to single nodes in the transmission network, most of the advantages of the easy-to-employ approach of forward markets in zonal systems seem to be lost. The most obvious drawback of using an LMP market underneath a forward market is the **expected low liquidity in each nodal contract** with its negative impact on transaction cost and efficiency of long-term price discovery due to the limited number of active market participants. For spot markets cleared in auctions, this is not an issue as the bids usually are given by costs, i.e., short-run marginal cost; here liquidity only matters as an indicator of infra-marginal rent potential to refinance investment.

The inclusion of the grid topology in the spot clearing of an LMP market requires the inclusion of the same information on grid state and development plans into the price discovery and modeling processes for long-term contracts.

If derivative contracts were written on each individual node, they would exhibit very low liquidity due to their small market size. At the same time, the number of contracts in the system would correspond to the number of nodes **making the hedging of geographically widespread portfolios rather complex and expensive**. Hence forward contracting would either require joint clearing across all nodes together with a clearing of FTRs, or the aggregation of nodes to trading hubs as reference price (underlying) for forward contracts. A joint clearing of forward contracts with FTRs would require a very high level of standardization and auctions.

3.2.3 Aggregation of nodes into larger market areas

In US markets, some of these issues have been addressed by **aggregating smaller nodes into zones or virtual hubs**, thus mimicking forward trading in zonal markets. In particular, the hedging of load has moved from nodal to zonal trading using "load zones". A similar approach can also be observed in European markets with smaller bidding zones, e.g., the Italian or the Nordic markets.

In the Italian market, generators are exposed to the seven bidding zones, whereas consumers are only exposed to the single national price called Prezzo Unico Nazionale (PUN). Derivatives contracts are written on the PUN, and producers manage the basis risk of the price difference between PUN and the price in their bidding zone.

Aggregating nodes into zones and thus establishing system prices like in the US, Nordic or Italian LMP markets creates **basis risk** for the price differential between the market in which the actual physical exposure is located and the market in which the financial hedging is performed. This issue can be addressed in several ways: If liquidity in the markets for system prices or on the preferred trading hubs is large enough such that basis risk can easily be managed by the traders themselves, no additional instruments are needed. If, however, such basis risk is not allowed to be incurred, additional instruments that cover the price differential are required. Such “spread contracts“ exist in a huge variety of forms. For instance, in Europe, there are spread contracts that are based on the price differential between two neighboring bidding zones and are essentially defined as a composite of two opposing positions in the respective futures contract.

In the Nordic markets, **Electricity Price Area Differentials (EPADs)** cover the price difference between the local market area and the system price. However, these instruments suffer from serving special hedging interests, e.g., there is a limited number of market participants or the contract is only attractive to one side of the market due to known power flows. They suffer from low liquidity and, therefore, high transaction costs.

In the US, due to the nodal nature of the market, **Financial Transmission Rights (FTRs)** [130] have been established as the proper tool to cover price differentials between different nodes. FTRs are issued by the system operators and thus backed by physical capacity. Their underlying is the congestion revenue incurred on a particular connector between nodes or regions [131]. Thus, they do not exhibit the financial risk that is present in the Nordics, and, therefore, it is easy to find suitable contractual counterparts.

3.2.4 Challenges and recommendations for derivative markets in an LMP system

It must be noted that a direct comparison between European and the US markets in terms of dealing with the challenges of derivatives markets in LMP systems is, in general, difficult. **Financial regulation** and **governance of utilities** differ significantly, and financial hedging has a completely different history in Europe than in the US.

In Germany, e.g., many of the smaller utilities are municipality-owned ("Stadtwerke") and thus subject to regulation forbidding or severely restricting trading financial instruments, as such trading is commonly perceived as speculative activity. Trading financial instruments with basis risk, as it would be the case for trading a system price in an LMP system, is per se speculative. Trading of financial instruments is also subject to European regulation, most importantly MiFID II. In particular, this directive states trading and position limits above which a banking license is required for the respective trading participant. However, *Stadtwerke* need to hedge if they are active on the spot markets, as otherwise any loss would have to be taken by the municipality and socialized.

In the US, many state-owned utilities have been or still are not allowed to hedge at all. The inability to hedge high electricity prices while at the same time being exposed to regulated low end-consumer prices has also contributed to the California energy crisis [132].

Summing up the fundamental challenge for derivatives in LMP systems in Europe, we arrive at the following conclusions:

> Current financial regulation only grants exemptions necessary for hedging to physical contracts.

> Derivatives markets in LMP systems need to be based on aggregated products (hubs/zones) to pool liquidity and reduce transaction cost. This makes every hedging contract a financial instrument. The necessity to manage risk on electricity markets with financial instruments instead of physical contracts needs to be reflected in financial regulation; in particular, German local government law needs to be adapted to allow prudent risk management for municipality-owned utilities using financial instruments on aggregate products.

> Instruments to cover price differentials between different nodes or towards trading hubs are required. The concept of FTRs most actively used in the USs could serve as a blueprint to reconcile established trading paradigms on zonal markets with the nodal structure of the physical market.

Given the current state of the markets and regulation in Europe, we can formulate policy recommendations for how to properly set-up derivatives markets in nodal systems: Current European derivatives markets for electricity feature large markets and huge liquidity. This is the basis for many trading strategies of utilities and traders and, thus, should not be compromised. An LMP system in Europe thus requires properly defined trading hubs or market areas. Low transaction costs due to large liquidity still outweighs the challenge of managing basis risk. The experience from the high liquidity of the German derivatives market that attracts (physical) traders from all over Europe supports this. In order to allow as many actors as possible to access such virtual hubs and zones, financial regulation currently barring participation needs to be revised. The regulation in member states and on EU-level in MiFID II has to be adapted accordingly, so that trading of derivatives on system prices – genuine financial instruments – is allowed if a sufficiently prudent management of basis risk can be ensured. In addition, auxiliary contracts such as spread contracts or FTRs should be introduced for those actors whose main focus is on basis risk and who can ignore transaction cost due to low liquidity on single-node contracts.

4 Horizontal, vertical and cross-sectoral integration of markets

While the introduction of LMPs at the national transmission level in Germany (or Europe) is the focus of the current whitepaper, such a system will, at the start, potentially not cover the entirety of Europe, nor reach the lower voltage levels of the electricity system, i.e., the distribution grids. Nonetheless, as it is one technically as well as institutionally interconnected system, horizontal interfaces (i.e., an integration in European market coupling) as well as vertical interfaces (i.e., a coordination with activities on the distribution level) are needed. Furthermore, the electricity system is connected to other energy systems and networks, such as heat, natural gas or – potentially in the future – hydrogen. In what follows, these three interfaces will be discussed.

4.1 European integration and market coupling

While it may be possible that the EU moves to LMPs in a single step, another option is that individual member states undertake the transition. It would be highly beneficial if, for example, Germany, Poland, or other EU member states implement LMPs as first movers, as suggested in our previous whitepaper [1]. On the one hand, compared to the current state, even a hybrid European market that couples LMP (aka. nodal) systems and zonal systems promises system operation and efficiency benefits under high levels of RES [133]. On the other hand, such first movers would reap the benefits for their own system, be in a better position to set future market standards, and offer important practical and institutional learning opportunities. However, as not to lose the existing advantages of European power market integration, it is **imperative to establish zonal-to-nodal coupling mechanisms** that ensure sufficient trading opportunities over several time frames.

In principle, European markets are currently integrated on day-ahead (DA), intraday auction (IDA), intraday continuous trading (IDC), as well as balancing (BA) time frames. Several options exist for coupling zonal and LMP systems [134]:

> Auctions (i.e., for DA, IDA, and BA)

> Sequential adjustments in the nodal market, after common zonal clearing (DA, IDC, and IDA)

> Pre-screening of bids (IDA, IDC, and BA)

> Aggregation of demand/offer curves by the nodal TSO (BA)

The superior implementation option for all time frames, including intraday[24], are **auctions** [134]. An immediate upside is the ability to consider several constraints simultaneously, e.g., both nodal and zonal clearing constraints (cf. [133] for a suggested formulation). Furthermore, auctions allow for a matching of several product types and deliver clear price signals. They also allow for the allocation of transmission capacity on a market base (rather than first-come-first-serve in continuous trading) and for transfers between regions where it adds the most economic value. In contrast to sequential adjustments of zonal market results, (Inc-Dec) gaming opportunities can be largely avoided. The introduction of frequent cross-border intraday auctions also promises benefits for zonal markets, in terms of liquidity, market power resilience, static allocation efficiency, and the efficient usage of cross-zonal capacity [135, 136, 85]. In order to implement these auctions, two approaches can, in principle, be taken:

> An integrated auction considers both the zonal markets and the LMP market simultaneously in a single algorithm (e.g. further developing existing FBMC algorithms, to be able to fully represent and solve a coupled nodal system). Here, also for zonal systems, the introduction of multi-part bidding as well as the introduction of pricing schemes with uplifts would probably be needed to ensure solvability under the given time constraints.

> An iterative coupling algorithm keeps the existing zonal clearing algorithms (EUPHEMIA) and new LMP pricing auctions) separately, but iteratively solves the two via coupling variables (linked to the

[24] In the intraday time frame, currently continuous trading is predominantly applied after a single opening auction.

cross-border flows or prices), until the solutions converge (e.g., building on existing approaches of coupling nodal to nodal systems [137] or alternative decomposition techniques).

However, for some transition period, LMP markets may still need to be coupled outside of auctions, for example in the context of continuous intraday trading (auctions are also recommended to be implemented in zonal pricing regions irrespective of the coupling to LMP systems, since this would alleviate the need for a coupling to continuous trading). Here, the **pre-screening of bids** for technical feasibility by the nodal TSO could be a feasible solution, where a trade-off between strict pre-screening (and limited liquidity) and loose pre-screening (gaming opportunities) needs to be made [134].

The balancing market is central to LMP systems as it ensures an efficient real-time market clearing and is, thus, a reference point for all "futures" markets (e.g., intraday or day-ahead). This consistency across all time frames avoids discretionary, non-market-based interventions, perverse incentives and gaming opportunities inherent in zonal pricing approaches. Therefore, the real-time market in the LMP system is taking up many (but not all) of the balancing tasks happening after gate closure in European markets. One way to interface the LMP real-time market with European balancing markets could be the **aggregation of demand/offer curves** by the nodal TSO, which would participate in the TSO to TSO clearing balancing mechanisms. This could be another suitable stepping stone as it can build on existing frameworks for central dispatching countries in the balancing guidelines (Article 27, Commission Regulation (EU) 2017/2195[25]).

One challenge that will need to be addressed is the coherence between sequential markets: as Bjørndal et. al. [133] point out, coupled zonal-nodal markets may deliver results violating transmission constraints even in the nodal systems, as the flows on the interconnectors are cleared under constraints (i.e., flow-based market coupling) that only partially reflect the full physical grid constraints. Thus, systematic differences in prices would exist between day-ahead and real-time (as real-time prices are usually based on the measured system state). In this regard, several options should be explored in the future, including an **adjustment of bids** by the TSOs and convergence bidding (and the associated risk of gaming).

4.2 TSO-DSO coordination

Historically, DSOs followed an invest-and-forget approach – enough capacity was put into the ground to meet all reasonable demand increases over a foreseeable future. With the spread of active consumers and producers on the distribution level and their associated higher capacities, as well as increasing correlations of production (due to local correlation of weather and RES production) and demand (due to the spread of electric vehicles and heat pumps), this strategy has come under scrutiny [138]. In order to tap into new potentials for flexibility, which are available often at the distribution grid (for example from flexible industrial processes, often connected at mid-voltage level, or electric vehicles and residential storage, connected at the low-voltage level), a coordination between the TSO level and the DSO level is necessary. Only then can local grid constraints as well as overall system constraints and efficiency be considered in the market clearing.

The more active role of DSOs in system operation, and the coordination with the TSOs is relevant and important regardless of the pricing mechanisms on the TSO level, and has indeed been discussed in the European context [139, 140]. However, the combination with nodal pricing promises a **coherent pricing framework over all network levels** [141], up to Distribution Locational Marginal Prices (DLMPs) [142, 143], leveraging additional efficiency and system security benefits. Several categorizations of TSO-DSO interaction exist. In its most succinct form, two idealized approaches can be distinguished for the long-run development [141]: a **DSO-centric model**, in which DSOs take up the responsibility to coordinate dispatch on their grid level; and a **TSO-centric model**, in which TSOs reach out into the distribution grid to directly coordinate distributed assets (via markets, not necessarily via direct control).[26] The DSO-centric model suffers from a fragmentation of the system and resulting inefficiencies if no coordination with the TSO is taking place [141]. Such a vertical market coupling [144] can, for example, be achieved through decentral optimization algorithms [145, 146], which are a topic of ongoing research. The TSO-centric model on

[25] https://eur-lex.europa.eu

[26] There are several intermediate solutions where responsibility is shared. The current set-up is relatively static, and several proposals exist on how to coordinate TSO-DSO interactions in the short- and long-run [144].

the other hand suffers from the loss of economies of scope that arise from the break of distribution grid ownership and control [141], as well as system security risks from centralization [144].

An additional challenge (not only) on the distribution grid is the design of tariffs [141]: Traditionally, **network tariffs** were static, provided little incentives for dynamically efficient behavior (over time and space), and were aimed at equitable cost recovery [141]. While nodal prices (also at the distribution level) give efficient price signals, they are insufficient to recover the full network cost under realistic assumptions [147, 148]. Hence, additional charges are needed to recover network costs, which, if set incorrectly, may distort price signals. One proposal to incentivize efficient behavior, also with respect to network expansion, are forward-looking peak coincidence network charges [149, 150], which work as follows: A certain share of network charges is to be recovered in those hours where the total demand on the network exceeds a pre-defined threshold level (the higher the excess of total demand, the higher the charge). While estimations can be given ex-ante, the final confirmation to be in a state of peak coincidence can only be done in real-time, and the charge can only be allocated ex-post, based on the realized power flows and the relative contribution of users during peak times.

Traditionally, market design and technology options at the DSO level have been tested in Europe in the context of the current zonal market design, including bilateral physical based trades at the TSO level. It may be advisable to explore early on how aspects like congestion management at the DSO level can be structured in the context of LMPs, including intraday auctions at the TSO level. In addition to traditional analytical and computational approaches, the investigation of TSO-DSO coordination could also include the definition of test regions against a (virtual) wholesale power market design with LMPs.

4.3 Cross-sectoral integration

In order to reach emission reduction goals, current conventional energy usage in energy systems needs to be transformed. Often this is done via **electrification**, so that currently independent energy systems are more closely linked to the electricity system. Such sector coupling is relevant in most future energy system scenarios [151]. This concerns both direct electrification of formerly conventional end uses (e.g., electric vehicles or heat pumps), but also other coupled energy infrastructures (e.g., heat and gas (hydrogen) networks). The distribution between these two solutions varies over different scenarios [151]. However, direct electrification – wherever possible – seems to be the most economically efficient solution.

Due to different technical characteristics, there is inherent storage of energy in these systems at time scales that need to be instantaneously balanced in the electricity grid [152, 153]. Furthermore, dedicated storage is usually more economic in coupled sectors than in the power system[27]. While integrated planning tools, as are commonly used for long-term scenarios, show that integrating the sectors is beneficial, they typically either assume that there are no transmission constraints within countries [152], or that the different systems are optimally coordinated both in space and time [151]. However, it is questionable whether such a linking can be efficiently achieved using a zonal pricing regime with cost-based redispatch because local opportunity costs for the use of electricity in coupled energy sectors will be difficult or even impossible to quantify in a regulatory manner. Hence, **LMPs promise to work as an efficient coordination device**.

How the concept of LMPs can be applied in a sector-coupling context is a topic of ongoing research [154]. In principle, similar forms of coordination as between electricity system operators are possible. Research on the existing coupling of natural gas and electricity networks [155] shows that a tighter co-optimization can achieve efficiency and enhance the security of supply.

> LMPs markets need to be integrated with other electricity systems - both on a horizontal (cross-border) level, as well as linked to more active distribution grids. Furthermore, with the ongoing energy transition the existing integration with other sectors (e.g. gas or heat) needs to improve. Concepts for ensuring a European integration over all time frames in case of national LMPs implementations exist, with common

[27] For example, it is usually more economical to produce hydrogen at times of low power prices, and then use it in an industrial process later, rather than storing electricity to produce hydrogen just-in-time for use in an industrial process.

auctions in all time frames as the key ingredient to ensure an efficient market coupling. TSO-DSO coordination as well as cross-sectoral coupling will become more important in future, and LMPs at the transmission level will be a solid basis for these undertakings to efficiently align local incentives over all network levels.

5 Long-term investments

In the long run, market participants are not restricted to planning with their existing generation capacities. They can expand or shrink, adjust the technological and local composition of their installations, develop innovative solutions, and exit or enter a market. From the regulator's point of view, the individual investment decisions should support the political objectives for the market. The German government, for example, defines "the secure supply of clean energy at a low cost" [156] as objectives.

To guarantee a reliable provision of electricity while achieving climate policy objectives, the correct decisions have to be made years in advance. Germany currently considers electricity from RES and hydrogen generated by RES as the main sources for a clean energy provision in the future. The replacement of fossil fuels and the electrification of industrial processes, heat, and transport will increase the demand for electricity, which requires further investment in generation.[28] Challenges arise from the intermittency of RES which need to be complemented with controllable generation or storage to provide electricity even in long periods of, e.g., a clouded sky.

This section describes challenges for long-run resource adequacy in an electricity system with a high share of intermittent RES and points out selected approaches to address them. Opportunities to recover investment costs are described, the role of price signals for investment decisions is delineated, and mechanisms to remunerate RES are discussed.

5.1 Recovery of investment costs

Long-term investments are made only if they are expected to be profitable. For example, firms can recover the investment costs for generation units by selling energy, providing ancillary services, and receiving resource adequacy remuneration.

Across Europe, countries differ in the revenue opportunities they provide. Germany relies largely on the energy market whereas France, UK, and Poland, for example, have an additional **capacity market**, where firms can receive payments for guaranteeing a certain supply capacity in a specified period. Hirth and Ueckerdt [158] provide a short overview of arguments for and against capacity markets. In general, an **energy-only market** should enable generators to recover their investment costs. Even the generator with the highest marginal costs can refinance the full costs with the revenues from times of scarce generation capacity, which yield the necessary contribution margins [159, 160, 161]. Demand response, intermittent generation, and locally differentiated prices influence price patterns, but do not change this basic principle [158, 162]. Capacity markets are introduced based on expectations of some kind of distortion of market outcomes relative to the competitive market reference point. As an example, the concerns that participants with market power raise prices above the level necessary for efficient investment as well as concerns about excessive costs for consumers during scarcity periods (as recently observed in Texas [163]) have led to **price caps** being introduced in all wholesale markets in Europe. These caps, in turn, can decrease price volatility and limit price peaks [164] that might be necessary for some firms to recover their investment costs. As another example, it has been argued that very high price peaks may be perceived to be so uncertain that they will be highly discounted and thus of limited relevance for investment choices; further, they may increase counter-party risks, thereby limiting opportunities for forward contracting, and thus negatively impacting investments. Capacity remuneration mechanisms are often introduced in order to account for underinvestment and ensure reliable supply. In this context, the **strategic reserves** continue to offer a promising third option [165]. They were implemented in Germany to secure sufficient generation capacity during the nuclear phase-out. When mechanisms to account for underinvestment are implemented, overinvestment or crowding out of more efficient investments need to be avoided. Overall, however, the discussion on capacity remuneration mechanisms can be separated from the question of zonal prices or LMPs.

Depending on the technology, the opportunities to recover investment costs may differ. For example, **RES investments** in many countries receive remuneration that is not available to fossil generation, and RES

[28] The German Ministry of Economic Affairs and Energy in July 2021 corrected its estimates of the electricity consumption in 2030 by 13 % as compared to the estimates of March 2020 [157].

remuneration is often differentiated along technology and location. Further, in pricing zones with high shares of intermittent RES, the wholesale price received by RES tends to be below average. Due to the weather-driven local and temporal correlation of generation from the same renewable source (e.g., wind or sun), these RES technologies typically produce in times when renewable electricity is abundant and prices are low (sometimes called self-cannibalization effect). For conventional generation units, high shares of intermittent RES affect revenue streams through more volatile prices and therefore reduced number of profitable full-load hours. With increasing carbon prices, electricity market prices increase when carbon-intense generation is at the margin, which benefits low-carbon power suppliers like RES [166].[29] In particular, controllable low- or zero-carbon generation units, like hydropower or biomass, may profit from such price increases, although their potential for capacity expansion is often limited by resource availability.

5.2 Prices as investment signals

Long-term investment decisions are based on expected revenues, which in turn rely on expected prices. Thus, a foundation for efficient long-term investments is a functioning short-term market. Firms need to predict prices as a basis for their decisions. **Regulatory stability and reliability** are therefore important cornerstones for efficient investments. **Liquid forward markets** can accumulate market participants' expectations in forward prices, guiding investors in their decisions and allowing them to quantify and to hedge their investment risks.

Since short-term markets contribute to the creation of investment signals, a **functioning spot market design** is essential to activate resources in a cost-optimal manner at competitive prices. Any other mechanism to support long-term investments should avoid interference by distorting participation or bids at the short-term market. Moreover, the multiplicity of investment signals created by such additional mechanisms should not create undue complexity and possibilities for exploitation.

Furthermore, with significant shares of intermittent RES, energy shortages may result more frequently from shortfalls of RES supply than from a shortage of installed total capacity in situations of peak demand. Energy shortfalls are then imminent when the sun does not shine and the wind does not blow for a sustained period of time, water reservoirs are emptied, and the remaining generation capacity does not cover demand. Remuneration schemes need to account for these **changing requirements for resource adequacy** and set incentives for investments in a technology mix that is able to satisfy demand rather than focusing on installed capacity [162, 168].

Investments that provide flexibility by allowing the fast adjustment of supply or demand can profit from price fluctuations and thus use these profits for their financing. Investments in **demand flexibility** include the adjustment of production processes by industrial consumers and adaptations in technology to automatically adjust load and to receive the necessary real-time price information. The deployment of energy-flexible technologies can reduce load peaks, relieve the grid, and reduce grid expansion requirements. It further contributes to the functioning of the system by limiting market power on the supply side when generation resources are scarce. As a result, price volatility is decreased, which reduces profitability of demand flexibility to the point where additional investments – either in more flexible demand or supply units – are not profitable. Thereby, market prices can incentivize efficient investments in demand flexibility. This can, however, be countered by incentives for not providing these and other flexibility services set by other instruments like certain network tariff schemes [169, 170, 171].

To create **incentives for investments in energy-flexible technologies**, Gómez et al. (2020) [172] propose flexible grid access, local market mechanisms for flexibility services, and cost-reflective grid tariffs. Under flexible grid access agreements, the DSO is given the right to control feed-in to the grid and withdrawals in order to operate the grid efficiently. In return, flexible market participants can be offered compensation for their flexibility, reduced connection fees, faster connection, or the opportunity to connect at all. Market mechanisms for local flexibility services can be used to procure distributed generation, demand response, or storage services to relieve grid stress. Challenges include determining demand for these services, delegating procurement responsibilities to DSOs, standardizing traded products, aggregating services, defining

[29] See [167] for potential problems for the electricity markets due to inconsistent carbon pricing policies.

market participants and managing competition (considering the grid topology), and coordinating transmission and distribution grid levels. Cost-reflective grid tariffs, as outlined in Section 4, contrast with quantity-based tariffs in that they reflect the grid costs incurred by the behavior of market participants. To this end, they allocate incremental grid costs to those users who stress the grid at times of maximum utilization. This generates incentives to invest in the efficient use of the network.

5.3 Enhanced investment signals through local price differentiation

Capacity may not be scarce in the entire grid, but at certain locations. This can be the result of the location choice being driven by the availability or the costs of the deployed resources, and the transmission capacity from these locations to the load centers being constrained. For example, large wind farms are built where the wind blows strong and steady, like offshore or at the coast, and lignite power plants are typically built close to the mine. Thus, investment decisions have an important **local component**, which will likely become more important for the system because increased intermittent supply strengthens the stress on the grid.

Locational price signals can be generated in multiple ways. Short-term markets, charges for grid connection or grid usage, capacity remuneration, and RES remuneration schemes can incorporate local differentiation [173, 174, 175]. **Locational price components** are provided in many countries and in many varieties. They may differ, for example, in their spatial or temporal granularity, in the eligible parties, in whether they come as a penalty or as a premium, and in whether they are determined by a regulator or on a market. As an example, German auctions for RES remuneration use or have used regulatory determined regional factors that influence winner selection and remuneration payments (to level the playing field between regions or to penalize local RES oversupply) and local quotas [174, 175, 176, 177]. LMPs can be used to incentivize efficient RES location if the remuneration scheme exposes RES to these prices (see Section 2).

Locally differentiated spot market prices provide information for investment location choices and set incentives to locate to relieve the grid [178, 179]. They incorporate costs for transmission losses and congestion so that these costs are accounted for in investment decisions [174]. Building capacity in regions with higher prices can then result in higher revenues from energy sales. However, by increasing supply (which may relieve the grid) it reduces the prices in these regions. Therefore, local price variation will not be fully flattened. Brown et al. [180] find empirical indications of location choices for combustion turbines and large combined cycle gas turbines being influenced by local prices, but they conclude that local price differences are not the major driver of location decisions in Texas.

Local price differences can influence investments in demand flexibility and storage. In regions with stronger price fluctuations, temporary demand reductions or shifts and storage are generally more profitable. Temporary grid congestion generates such local price fluctuations, and a flexible demand or storage can support the system and relieve the grid best if it locates in such areas. The generation of hydrogen from RES has an incentive to locate close to the generation units if prices there are below average.

5.4 Investments in RES

For a climate-neutral EU in 2050, the share of RES has to grow (see Figure 3). The use of electricity or other RES-based energy sources like green gas to replace fossil energy in the industry further increases the need for RES capacities. RES generation is characterized by high investment costs and low or negligible variable costs, which distinguishes it from conventional generation.

Demand flexibility and storage, as well as sufficiently high carbon prices (see [166]), may counter the self-cannibalization effect and guarantee a revenue stream for RES that incentivizes investment. This may decrease the need for additional remuneration. Regulatory uncertainties linked to carbon price levels, market design, grid expansion, and other factors may however imply that investors require long-term price guarantees to finance RES projects. As only a fraction of the demand is in a position to sign long-term contracts (which are an alternative means to achieve a guaranteed long-term price), government-backed auctions for long-term contracts may thus remain essential for reaching renewable targets.[30]

[30] The long-term contracts can also reduce electricity costs for consumers. May et al. [181] illustrate that publicly backed contracts

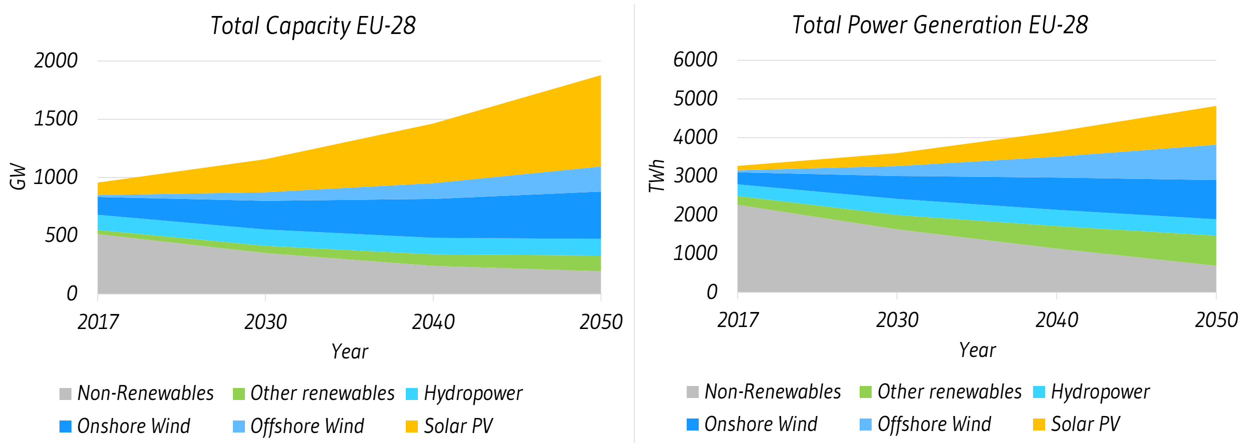

Figure 3: Development of RES capacity and RES power generation 2017 to 2050 in the Transforming Energy Scenario by IRENA. The scenario describes a path to keep the rise in global temperatures below two degree Celsius. Data from https://www.irena.org/remap, July 2021.

Currently, many countries remunerate investments in RES, using a variety of mechanisms, like preferential loans, RES portfolio standards, feed-in tariffs, and premium schemes like fixed premium, sliding premium, or Contract for Difference (CfD) [174]. A common remuneration scheme allocates long-term remuneration through **auctions**, in which the firms that demand the lowest remuneration receive it. Auctions address a problem of asymmetric information: the regulator is less informed about the necessary remuneration than the firms. Auctions can reveal such information, can select the best projects (and, sometimes, technologies), and give the regulator more control over the capacities than the previously used predetermined feed-in tariffs. A total of 106 countries have used this instrument as per 2018, with increasing remunerated capacities and declining remuneration payments per energy unit over the past years [182].

Remuneration can be provided based on the project's capacity or based on the energy generated. Remuneration schemes that remunerate per unit of generated energy and usually allocate the remuneration via an auction are commonly subdivided into the **fixed premium**, the **one-sided sliding premium** (or one-way CfD) and the **CfD** (or two-sided sliding premium). These remuneration schemes can be used both in combination with zonal pricing and LMPs at the electricity markets and the basic trade-offs are the same. With one-sided sliding premium and CfD under LMPs, a natural choice of the reference price, relative to which remuneration is determined, is the local price at which the generation unit trades its generated electricity.[31]

The three market premium schemes differ in the exposure of remunerated generation units to locational market prices. On the one hand, limiting market price exposure reduces the **investment risk**, thereby decreasing capital costs and enabling entry by more diverse firms. Whereas fixed premia fully expose RES to market prices and add a fixed renumeration, one-sided sliding premia work as a price floor. CfDs largely shield investors from market price risks. As levelized investment cost of RES approach wholesale market prices, both fixed premia and sliding premia converge to zero, because investors require no support and bid zero in the auction. Thereby these premia lose their risk mitigation characteristic, whereas CfDs continue to hedge price risks [183], with estimates of reductions of levelized cost of electricity of up to 30% in case of zero bids in the one-sided sliding premia and fixed premia schemes and resulting full market price exposure [181, 183, 184].[32] On the other hand, market price exposure shifts emphasis from

for difference can reduce costs per MWh of RES generation by about 30% as compared to a system where a large volume of RES projects is project financed without publicly backed remuneration mechanism.

[31] Shielding holders of existing fixed premium or one-sided sliding premium remuneration contracts from locational price differences when transitioning from a zonal to a nodal market can pose challenges, see Section 7.2.

[32] It is essential to avoid regulatory risk wherever possible and to keep the market risks calculable so as to provide a stable environment for investments [185]. The optimal extent of RES exposure to market price risk, and whether it is efficient that producers and consumers or society bear this risk is being debated and may vary across technologies and their maturity [158, 183, 185, 186].

investment costs to the **market value** when selecting projects for remuneration.[33] As a result, feed-in-tariffs and premium schemes have been found to have different effects for the choice of technology, e.g., whether to install a system-friendly wind turbine that produces also with low wind speeds or a wind turbine that requires a strong wind to produce [188]. While the technology choice under the premium supported the system better than under the feed-in-tariff, it did not achieve the system-optimal level. Market-value based differentiation of remuneration, as suggested by May [188] to improve system-supportive technology choice under tariffs, could be integrated into the auctions that allocate premium schemes like CfDs and could thus create incentives for technology choice, technology specification, and locational choice.

The different remuneration schemes also differ in the information they generate and in the incentives they provide, e.g., for operation. As an example for information generation, with a fixed or a one-sided sliding market premium, a zero remuneration price would signal that RES expect to be profitable without support. Such a direct signal of **market integration** is not generated by auctions for CfDs. Furthermore, **incentives for the operation** of a RES unit can be influenced by seemingly small adjustments to a scheme. One-sided sliding premiums and CfDs use the strike price determined in the auction and a reference price to determine payments from or to the party that backs the contract. If the reference price is the market price at which the unit sells its energy, under both schemes the RES unit will feed in all the energy it can generate. If the reference price deviates from this market price, e.g., by being the average over the market prices as is often used, this can influence the operating incentives. As an example, if at some point in time the reference price is high above the strike price but the market price is low, a CfD-remunerated RES may prefer to stop feeding in energy although the market price is positive. In practice, the existing monitoring of site-specific wind speeds in the context of remuneration during periods of negative prices ([176]) would also allow for the identification and prevention of such behavior.

Moreover, the RES remuneration schemes need to be adapted to the **changing requirements**. With decreasing need for remuneration, different characteristics of the remuneration schemes come to the forefront, influencing the trade-offs between schemes, as outlined in the previous two paragraphs. In anticipation of or in reaction to changes in the environment, additional components might have to be integrated into existing schemes, e.g., requiring additional payments from project developers to capture rents from scarce sites or grid access,[34] pausing remuneration when prices are negative,[35] and a variety of local components that have already been mentioned. Such new constraints and requirements need to be carefully integrated into existing concepts without creating a distortion of incentives.

Multi-attributive auctions, in which a bid is not only evaluated by the bid price but also by other attributes relevant for bidder selection, are an alternative to a market-value based differentiation of remuneration. Multi-attributive auctions also offer flexibility for bidders. They attempt to ensure that the remuneration determined in the auction reflects the system value of the produced power. This enhances efficiency [175]. The local and technological components mentioned above are examples of such attributes, but auctions could be enhanced by further bid attributes, for example on requirements on insurance against price risks, remuneration adjustment over time, and length of the remuneration period. Further, combinatorial auctions may be considered if firms participate with multiple heterogeneous projects in an auction and request non-additive remuneration [191].[36]

[33] See [187] for an overview and for mitigating effects of remuneration schemes on market power in the intraday market. See [1] for differences of different premium schemes for bidding behavior.

[34] This can arise with a fixed or a one-sided sliding premium (but not with a CfD) when all awarded bids for remuneration are zero and, e.g., the award of the remuneration includes a valuable grid access. For example, in Germany a second auction round for payments from firms to the government (i.e., negative remuneration), which would be conducted to differentiate between zero-bids, was part of the concept of the Federal Ministry for Economic Affairs and Energy [189]. However, in the decision on the law it was replaced by a lottery to be applied if a selection between multiple zero bids has to be made [190, 185]. The lottery does not allow firms to compete, thereby raising remuneration above the competitive level, and raises efficiency issues due to the non-differentiation between bids and incentive issues, especially if projects can be reassigned between firms after the auction.

[35] For example, in Germany no remuneration is provided if spot market prices are negative for more than four hours [176] (and the eligibility period for remuneration is extended by these periods).

[36] Note, however, that translating remuneration for a combination of projects to remuneration per MWh generated by the individual projects is not straightforward and can impact bidding incentives.

To increase the share and capacity of RES and to adjust to the challenges caused by their intermittency, investments in RES, in complementing supply sources, and in demand flexibility and storage will be necessary. Grid expansion combined with locational price signals manages the stress on the grid. The locally differentiated information generated by LMPs can be used to guide system-supportive investments in generation, in flexibility, and in the grid. Reliable, informative, and non-distorted price signals are necessary to guide efficient long-term investments. Functioning short-term markets are the basis of such price signals, and additional markets or remuneration schemes should be designed such that they do not distort short-term market incentives.

6 Digital transformation

Recent developments in information technologies allow for new ways of organizing electricity markets and systems, e.g., by making them more connected, intelligent, efficient, and reliable through increased remote communication and automation [192, 193, 194]. By doing so, information technologies add value to electricity systems and, on the one hand, "enable" novel ways to organize the interplay between the stakeholders in the electricity system and, thus, innovative market designs. However, on the other hand, information technologies need to "align" with the requirements of future electricity markets and systems and cope, e.g., with increasing decentralization and variable RES. Thus, the digital transformation is closely linked to the market design transition, in which market design options and information technologies co-evolve.

6.1 Status quo and challenges of information technology usage for the market design transition

In our previous whitepaper [1], we have outlined nine information technology classes that currently impact electricity markets and systems. These technology classes comprise sensor technologies, data transmission technologies, cloud technologies and high-performance computing, database technologies, data analytics, Artificial Intelligence (AI), digital platforms, interfaces, and the overarching field of safety, security, and privacy. Introducing these technologies in electricity systems and applying them to current, energy-related technologies positively contributes to facilitating the market design transition from zonal pricing to LMPs in Europe. For example, the different technology classes like, e.g., sensor technologies, may be applied to the existing grid infrastructure, in particular, to decentralized lower level grids (e.g., micro grids), and enable real-time feedback about grid utilization and available grid capacities. Reflecting real-time grid utilization is important in an LMP system in order to mirror grid scarcities and congestion in local market prices.

Currently, in the German electricity system there is a coexistence of legacy technologies and more progressed information technologies. Also, many new energy-related applications are emerging that build upon the exploitation of information technologies [195]. Still, many of these applications seem to be at a rather early stage [196] and are limited to the specific use case of energy trading. Given the unbundling in European countries, **energy trading ("liberalized part")** is strictly separated from the operation of **energy infrastructures ("regulated part")** with the aim of ensuring competition while still operating grids in an efficient manner. In the liberalized part, information technologies will permeate as soon as they provide a significant competitive advantage, at least if there is sufficient awareness with the respective decision makers. There are various examples of energy-related applications that use information technologies to exploit (upcoming) opportunities in electricity markets. For instance, timing-based applications can process price signals from the market and incentivize producers and consumers to provide their flexibility [197]. A more comprehensive overview of new energy-related applications enabled by digitization in the liberalized part of the electricity system are provided by Küfeoglu et al. [198] and Loock [195].

As such, we assume that – at least in the long-run – participants in the liberalized part may have an advantage in the exploitation of information technologies' potentials. In contrast, in the regulated part, the adoption of information technology is largely influenced by regulatory specifications. This results in different speeds for the implementation of information technologies in the electricity system and a very heterogeneous landscape of information technology usage. An example for the challenges in the regulated part in the German electricity system is the planned introduction of advanced metering infrastructure (smart meter roll-out). This has been introduced by the regulator in 2015 [199] with the aim of having all metering points equipped with smart meters by 2032. To date, the German roll-out has been stopped due to concerns regarding the security of the devices, while many other European countries already have completed the introduction process [200].

In summary, the introduction of LMPs in the Germany involves different stakeholders with a very heterogeneous degree of information technology usage. While the tasks and responsibilities of major stakeholders in the regulated part (especially grid operators) may not change fundamentally by the advent of digitization, the digital transformation may bring about major changes for other market participants in the liberalized part (e.g., market platform operators). Still, market participants in the liberalized part may be able to cope with these transformational changes as they make use of information technologies in a more agile manner and are induced to exploit the corresponding business opportunities.

A one-step LMP introduction would constitute a major change also in terms of information technology modernization and will require certain investments (e.g., in digitizing and partly replacing the current (IT-)infrastructure) that market participants have to undertake. The anticipated modernization efforts, thus, call for a **swift LMP implementation** to provide solid perspectives for the current “pioneers” (e.g., mostly the market participants from the liberalized part) in information technology usage. Next to this, also the regulated part must be enabled to benefit from advances in information technologies by **adequate regulation**, for instance to improve the information flow between different grid operators and grid levels.

6.2 Information technologies as a facilitator for LMPs

LMP systems already require a certain amount of information technology usage, e.g., for collecting and processing the necessary data to compute the dispatch. Without the usage of information technologies, LMP-based markets would not be able to function due to a lacking grid transparency in real-time [201]. Thus, information technologies serve as an enabler in this regard. Still, there are further specific use cases tied to information technologies that might mitigate potential disadvantages that are often associated with LMPs. Thus, future **information technologies serve as a facilitator** on top of the general enabling function. Examples for such facilitating function are:

1. Addressing the challenge of higher price volatility by better **price forecasting**: The expected increase in price uncertainty and price volatility induced by LMPs [202] is both an opportunity and a challenge. For flexible market participants, the increasing volatility offers higher revenue potentials. Meanwhile, advances in data analytics and machine learning, e.g., by the help of neural networks, can further improve price forecasting and also allow an economic use of forecasting algorithms for specific nodal prices for companies [203].
2. Information technologies can enable LMPs with high temporal and regional granularity and allow for participation in regionally resolved markets at **lower transaction costs** [204]. Reduced transaction costs may attract more market participants and, thus, alleviate concerns of low liquidity [205]. Moreover, novel algorithms with increased performance allow to compute LMPs also on the distribution level [206]. To date, a full implementation of LMPs on the distribution grid level (DLMPs) based on mathematical optimization seems to be infeasible due to a lack of adequate algorithms [201]. Further progress in **optimization algorithms** and computational power might help to enable the LMP introduction also on this level in the future.
3. Addressing the problem of market power abuse: Market power and collusive behavior is seen as another challenge that needs to be considered when locational price signals are implemented. The use of information technologies allows for more efficient market monitoring and can also facilitate the detection of “undesired” behavior in such markets, which is increasingly relevant in fine-granular markets. Especially a combination of AI-based technologies, e.g., for pattern recognition and anomalies detection, and Distributed Ledger Technologies (DLT), e.g., the blockchain technology, can help in this context to ensure a high degree of **automation** and to implement appropriate **trust mechanisms** that enable competitive and efficient electricity trading.
4. Digitization also increases the importance of consistent market designs, like LMPs, that **avoid gaming opportunities** associated with redispatch in zonal pricing systems. Decentralized algorithms might otherwise individually or in unanticipated interactions reduce efficiency of market outcomes or even put system security at risk (Inc-Dec gaming).

Still, an increased usage of information technologies also brings new open questions that need to be addressed. First, information technology is a driver of electricity demand by itself [207], especially computation-intensive technologies like DLT contribute to electricity consumption, so there is always a trade-off between mere technology induced consumption and additional electricity demand [208]. Second, the increase of potential attack points for energy systems also increase the requirements for data security and resilience against external attacks [209]. Third, in critical infrastructures like the electricity system there will always be a coexistence of technical legacy systems that are gradually replaced by more recent information technologies, making the orchestration of "old" and "new" technologies challenging.

As such, it is not an automatism that the introduction of new information technologies always increases the efficiency of the electricity system. It is important to use the potentials of information technologies in an efficient and effective way, but not having information technologies as an end in itself.

6.3 Reconsideration of IT-based market roles in an LMP system

During the market design transition, also the distinction between market participants, their market role, and their respective attributes (i.e., their assigned tasks and responsibilities) are important points to consider. Here, market participants refer to legal entities or natural persons that are active in electricity markets, e.g., generation companies or (industrial) electricity consumers. These market participants usually fulfill a certain Information Technology (IT)-based role that comprises, e.g., an interface for communication with other market roles and follows a predefined communication protocol [210]. Within this IT-based market role, market participants are assigned certain tasks and responsibilities as role attributes.

In the course of the LMP market design transition, however, these IT-based market roles may change, leading to a reconsideration of market roles and their respective attributes, i.e., assigned tasks and responsibilities. This means that established market participants will continue to exist, but with potentially **altered IT-based roles, attributes, and relationships** to other market participants [207].

For instance, as the transition to LMPs quite naturally alters market clearing, the role of **market operators** could change. So far, market operators – represented, e.g., by power exchanges – are mainly responsible for matching aggregated electricity supply and demand and computing the market clearing price and quantities. As discussed in Section 3.1, one of several options in a future LMP system is for market operators to increasingly take into account available grid capacities and jointly determine market outcomes and physical dispatch using the above-mentioned digital tools. Thus, the role of market operators would change to a more integrated role, e.g., similar to the position of an ISO that not only administers electricity markets, but also parts of the electric grid and therefore integrates the tasks and responsibilities of various market roles. Depending on the concrete design of such an integrated ISO-like market role, the technical infrastructure of electricity trading will need to adapt involving, e.g., new trading platforms, market clearing algorithms as well as trading products.

Moreover, when transitioning to LMPs, the role of Balancing Responsible Parties (BRP), who are currently matching supply and demand in their respective portfolio and region, may change as well. This may be the case, as LMPs effectively account for physical network constraints and reduce the need for physical network balancing and – in the case of BRP – also for economic balancing [211]. Thus, existing market roles like BRP may develop further, such that they closely integrate (physical) network operation and (economic) balancing.

As another example, market roles like, e.g., **electricity consumers**, may change in a (digital) market design featuring LMPs. In particular, electricity consumers (like industrial companies) can more actively participate in electricity markets by the help of information technologies and a more decentralized market environment with BRP. Their role as passive electricity consumers might thus change to a more active role (e.g., "electricity trader" or hybrid "prosumer"), engaging in market interactions and procuring electricity directly from LMP markets. However, this requires adequate support through information technologies, e.g., in the optimization of electric vehicle charging [204].

Besides market roles, the transition to LMPs may also alter the attributes (i.e., completely new tasks and responsibilities) assigned to different roles. Since the transition to a market design with LMPs also entails a digital transformation, e.g., in the form of advanced smart-meter infrastructure, market participants will face enormous amounts of data [212]. This entails new tasks for grid operators in the form of data management and security processes. As a result, their performed tasks and responsibilities extend from managing infrastructure to **managing data**. In this regard, grid operators may adopt a "Utility 4.0" market role that acts as digitized (public) service provider that closely addresses the individual needs of electricity consumers and other market participants.

During the market design transition, policymakers, researchers, and practitioners need to address the question of how IT-based market roles evolve *precisely* and which new interfaces and interactions emerge between the different roles. In particular, this involves reconsidering the specific tasks and responsibilities attributed to market roles, while ensuring continued existence of the respective market participants, i.e., private firms or public utilities. Future research may provide additional insight in the evolution of IT-based market roles, e.g., by gathering empirical evidence on market roles and their (changing) attributes.

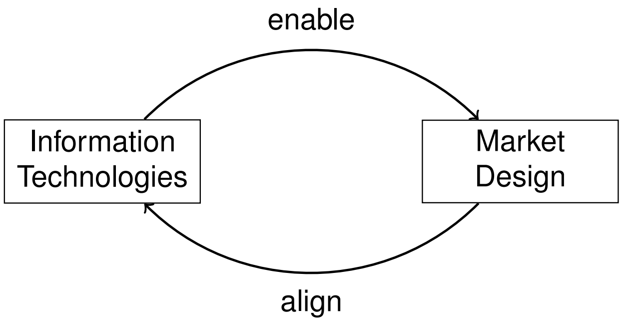

Figure 4: Align – enable relationship of market design and information techologies: information technologies enable innovative market designs, but, at the same time, need to align to new technical requirements

As outlined in this section, information technologies perform a dual “align – enable” relationship in light of a market design transition towards LMP. This means that information technologies, on the one hand, enable new market designs like LMPs but, on the other hand, also need to align to the new technical requirements involved.

As a result, policymakers and regulators need to be aware of this duality and rethink IT-based market roles, which may, ultimately, change the way (future) electricity systems are composed and governed. Thus, market design and the accompanying regulatory framework need to actively govern not only the market design transition, but also the digital transformation involved. To effectively exploit the potential of information technologies in the market design transition, a suitable **regulatory framework** needs to be in place, which does not restrict but supports the enabling function of information technologies. Only if information technologies are allowed to develop freely (while still maintaining privacy and ethical requirements), they may unfold their full potential concerning the implementation of an LMP system.

Therefore, jointly considering the market design transition and the corresponding digital transformation allows to effectively govern the transition process as well as future, decentralized LMP markets. Thus, policymakers may actively shape the transition process, instead of merely reacting ex-post to new technical developments.

7 Accompanying policy instruments and regulatory framework

This section discusses accompanying policy instruments and the regulatory framework, e.g., for grid expansion or market power mitigation. While there is no clear demarcation between electricity market design and accompanying policies, we focus here on accompanying policies that address key concerns of market participants, policy makers, and energy consumers involving the distributional effects of an LMP pricing system, including the abuse of market power. This section examines the expected extent of such effects and discusses complementary policy measures that may be necessary to address these concerns.

7.1 Distributional impacts of LMPs

In principle, LMPs could lead to price differences between nodes. However, as also discussed in Section 2, studies on the introduction of LMPs in Germany [53] based on historical data show that – while in a few hours significant price differences exist (which incentivize locally efficient behavior) – over longer periods (e.g., a week or the entire year) **price differences between nodes are rather small**. They rarely exceed 2 EUR/MWh, even in weeks with higher price differences, such as winter weeks. Looking into future years, with possibly higher congestion levels, a study by Schmidt & Zinke [35] focuses on wind power investments under zonal and nodal pricing and finds that in 2030 (assuming exogenous grid, PV, and offshore wind investment) the majority of nodal prices for demand are in the range of 60 to 65 EUR/MWh and thus price differences are in most cases smaller than 5 EUR/MWh (with a minority of prices up to about 75 EUR/MWh and down to 43 EUR/MWh, reflecting price differences of 10-20 EUR/MWh on average). So while strong locational incentives are given for a minority of nodes (see Section 2 on electrolyzer locations), for a majority of nodes the distributional impacts are rather low. While zonal study results cannot be directly compared to LMPs, they can give an indication of averaged price differences and developments over time. A study on zonal north-south splits by Egerer et al. [213] finds average price differences of 0.4 EUR/MWh to 1.7 EUR/MWh (for the basis years 2012 and 2015), while a more recent study by Fraunholz et al. [214] finds initial price differences of 8.1 EUR/MWh, which decrease as grids are extended.

Overall, these can be be considered small differences, especially **compared to existing tariff differences in distribution grids** (cf. [215]) which reach up to 64.8 EUR/MWh for industrial consumers between the most and least expensive distribution grid in Germany (122 EUR/MWh difference for household consumers), and still reach 12.8 EUR/MWh, on average, for industrial consumers between the most expensive state (Schleswig-Holstein) and the least costly state (Saarland) (40.7 EUR/MWh difference for household consumers).

If policy makers consider it necessary to compensate for the moderate local price differences from LMPs, several approaches to mitigate distributional impacts can be considered. As discussed in Section 2, **Financial Transmission Rights (FTRs)** can be allocated to consumers and producers to offset distributional impacts. An allocation of FTRs based on historical production (or consumption) volumes can offset almost all distributional impacts on the demand side, and a large share on part of conventional generation [53].

Due to their varying output characteristics, renewable generators can be less well compensated via FTR obligations[37] (i.e., FTR Contracts for Difference). While FTR options[38] might be a suitable alternative, they suffer from severe drawbacks in terms of revenue adequacy and the amount of FTR contracts that can be allocated. Hence, addressing the concerns of RES generators via an adaptation of renewable remuneration mechanisms seems to be the more promising route (see Section 7.2). Importantly, renewable policy (specifically via CfDs) may also be used to address the concern of industrial users to gain access to long-term contracts for affordable low-carbon electricity, which is a topic that goes beyond the hedging of locational price risks (as discussed in Section 5).

[37] An FTR obligation is usually defined as the baseload difference between two nodes, or between a trading hub and a node. It pays out irrespective of whether the owner generates power or not.

[38] Contracts that allow, but do not force generators to sell at the price of a certain node

7.2 Transitioning of existing renewable policies

To determine the need for adjustment of existing renewable remuneration mechanisms in Germany, a distinction between small-scale installations with a feed-in tariff and large-scale installations under the current sliding premium regime needs to be made. Existing **feed-in tariffs** do not need to be adjusted as they are independent from electricity market prices and have little to no flexibility to react to prices.

For larger scale installations supported by a **sliding premium** regime, regulatory credibility requires that states should honor their previous policies. Currently, the sliding premium system pays to RES projects the price difference between the reference price, which is defined as the monthly average of day-ahead market values of all installations in the respective technology group (wind or photovoltaic), and the strike price that was determined in an auction or for older projects was administratively set. The remainder needs to be earned by direct sales of renewable electricity on power markets (often done via aggregators), with balancing responsibility resting on RES (or their aggregators). With the introduction of LMPs, however, the renewable generator is not exposed to a uniform zonal price anymore, but to the node that it is connected to, which may have quite different market values than under uniform pricing.

As a result, a transition to LMPs without any **adjustments to the renewable remuneration mechanisms** would impact the financial viability or profitability of existing renewable projects, depending on how the existing policy is transitioned. Currently, sliding premia are defined on the average market value of a technology group over a month, i.e., the payment is the difference between the market premium and the weighted technology basket price. The remaining revenue needs to be earned on the electricity market. A direct transfer of this concept (with a weighted basket price and individual responsibility to sell at local market prices) would result in large welfare effects: A project with a sliding premium on a local reference price located in a region with lower LMPs would forgo revenues, while a project in a region with higher LMPs would incur additional profits. At the same time, RES would be exposed to an increased local balancing risk. One option is to transfer the sliding premium to hourly contracts-for-difference with their existing strike price and the respective nodal price as underlying. This avoids excessive profits from the transition while maintaining a direct market link to the local price of the RES project. However, the option value of the sliding premia in case of high market prices would be lost for market participants. Another option would be to maintain the sliding premium, defined on a synthetic German-wide market value of RES, but substitute the responsibility to individually market the electricity at the local price, with earnings at the basket price level. The individual power injections at the nodes could instead be collected by the TSOs. Additional research is needed to investigate these and other options in more detail.

7.3 Creation of a pro-active and automated market power mitigation

As already discussed in the previous whitepaper, LMPs in principle increase the level of competition across all market participants compared to zonal pricing. This is mainly due to the more efficient and flexible allocation of grid capacity which increases the elasticity of net demand and, thus, reduces the profitability of exercising market power.

However, in particular in small load pockets, specific generation assets can be in a pivotal situation, e.g., essential to meet demand. This is the case both in nodal and in zonal pricing systems. Currently, the German market design envisages cost-based redispatch, e.g., mandates these generation assets to produce if they have not already scheduled power production, and then remunerates the assets based on audited costs. In an LMP system, different market power mitigation procedures have been established and are sometimes even combined to address the situation [216]. The introduction of such a mechanism would also be advisable in the context of LMPs in Germany, enabled by underlying digital tools as described in Section 6. First, **bid-caps** based on audited, pre-negotiated, or competitive benchmark prices [216] could apply automatically to generation assets if they are located in a load pocket with largely binding import constraints (either determined by an automated pivotal supplier rule, or by the "conduct and impact" approach [216]). Second, **market power monitoring** is already gradually being improved with increased transparency requirements. This information can be used on a more ongoing basis to identify bidding mistakes as well as strategic bidding behavior. Unit-based bidding will significantly improve the quality of such a monitoring compared to what is possible under current portfolio-based bidding. This will be particularly important with any further increases of wind and solar power generation, as this inherently increases intraday trading volumes and reduces the market power mitigating effect of longer-term contractual arrangements [217].

7.4 Grid expansion

While LMPs efficiently make use of the existing network resources, this does not change the **fundamental need of an optimally-sized (i.e., welfare-maximizing) electricity grid**. Indeed, Perez-Arriaga et. al. [147] showed that, due to lumpiness of investments (and further reasons), income from nodal congestion rents covers only 25% of total costs of a representative highly meshed transmission grid. As a result, network planning and regulation in LMP systems is, in practice, not fundamentally different from zonal systems, with a common planning regime and regulated revenue to cover transmission costs [218]. Nonetheless, the information of LMPs can be utilized in such a planning process, or enable individually profitable merchant investments [218].

> With the introduction of LMPs, accompanying policies and changes to the regulatory regime may be needed. Distributional impacts from LMPs are likely to be small for most market participants, and may be effectively compensated via the allocation of FTRs. Existing renewable policies may need to be adjusted in order to avoid windfall profits, or unexpected losses, with several policy options available. While locational market power exists both in nodal and zonal systems, the strategies to address it are different. Zonal systems employ cost-based compensation in redispatch, whereas LMP systems can more transparently identify and mitigate abuses using pro-active and automated market power mitigation tools. The grid expansion planning and regulation is not fundamentally different in zonal and LMP systems; however, the planning may benefit from transparently available LMPs.

8 Policy implications

As outlined in the previous whitepaper [1], it is likely that the rapid expansion of RES will put a strain on the existing grid infrastructure. An efficient grid usage will be a key component of a successful energy transition. We therefore recommend that Germany introduces LMPs in a one-step transition, driven by fundamental changes in the energy system as well as new information technology. While such a transition is associated with certain costs, experiences of past LMP implementations [219, 220] show that the benefits of introducing an LMP system in terms of efficiency gains and consumer welfare outweigh the implementation costs of developing and adjusting systems on part of TSOs, power exchanges, and other market participants (often within a single year of operation, in all cases over a longer-term horizon).

This section summarizes the policy implications from the previous sections, outlining a long-term vision for a revised German and European market design. Furthermore, we discuss no-regret market design options for improvements of the current system which at the same time also enable a later implementation of LMPs.

8.1 A vision for a revised market design

This whitepaper's vision is to have a **locationally and temporally fine grained market** in Germany that enables all potential players and technologies to participate using modern information technologies, thus enhancing **competition** and **efficiency** in the electricity system, whilst improving **system security**, **limiting distributional impacts**, and maintaining a **high integration** in the common European electricity market – as the basis for, e.g., a sustainable and competitive industry in Germany.

In order to achieve these objectives, Germany will need to reform parts of the electricity market (see Section 3): The core element of such a reform are **locationally and temporally fine grained prices**, at first at the transmission grid level. They can be subsequently extended to lower voltage levels, possibly using simplified user interfaces. The central markets for short-term trading include:

1. A final real-time auction
2. Several intraday auctions
3. A day-ahead auction

Central to this market design is the final **real-time market**, which defines the clearing prices that determine production and demand across all nodes of the system and the remuneration for all energy transactions not covered by agreements in preceding markets. The preceding markets are, in effect, forward markets to enable a coordination of production. While the day-ahead market is the first market to coordinate the commitment of units, several intraday auctions are utilized to let the market adjust to resolving uncertainty around demand and renewable production.

All markets should be **co-optimized** with the procurement and provision of ancillary services, and utilize standing multi-part bids in order for all market participants to offer their full capabilities to all relevant market services, while minimizing transaction costs.

The clearing of markets and resulting prices should ensure that overall welfare and **market efficiency** is maximized. It progresses in network modeling and integrates active network controlling devices. The pricing rules should give efficient short- and long-term incentives for all market participants.

Information technologies will play an important enabler role to implement an efficient LMP system, for example to leverage the potential of more active consumers and smaller market participants. This, however, requires that a suitable regulatory framework is put in place, which does not restrict but supports the enabling function of information technologies.

Several **trading hubs** should be established, serving as focal points for **liquid trading of derivative products**. Importantly, a "national hub" would need to be defined as a reference point for existing contracts on the zonal price. Secondly, regular FTR auctions should be conducted to create a solid primary market for financial transmission rights, that enable all market participants to hedge their locational price risks. A secondary market will ensure trading opportunities between auctions. In order to allow for a broad market participation, financial regulation currently hindering participation needs to be revised. The regulation in member states and on the EU-level in MiFID II has to be adjusted, so that trading of derivatives on system prices is enabled for all market participants (subject to a requirement of prudent risk management).

While introducing the LMP market design, the **tight integration with the European markets** should be ensured (see Section 4). Under such a continued integration, and with growing shares of RES, both the country which introduces a nodal market and its zonal neighbors are likely to benefit [133]. Several principal mechanisms to couple zonal and nodal systems exist at the day-ahead, intraday, and real-time stages, with coupled European auctions playing a central role over all time horizons. These options should be investigated and developed further.

In the future, more and more active participants, including industrial demand flexibility, will be located at the distribution grid level. Nodal pricing even on the transmission grid level alone can help align actions on the distribution grid with system needs. Nonetheless, a tighter **coordination between TSOs and DSOs** will be necessary, to also dynamically consider system needs on the distribution grid level. This can be achieved by either extending the current responsibilities of TSOs, or by vertically coupling distribution level markets with the wholesale market (see Section 4). Further research should be conducted to find engineering and market solutions to this coordination challenge.

LMPs may lead to limited **distributional impacts**, with locational price differences probably below the levels of existing differences in distribution grid tariffs in Germany. Such distributional impacts can be offset using the allocation of FTRs for consumers and conventional producers. Existing renewables remuneration mechanisms can be adjusted in the transition to an LMP system, to account for the change in the market that underlies the contracts and the associated redistribution of profits.

8.2 No-regret reforms in the current system as an enabler of LMPs

While there are good arguments to perform the transition to locationally fined-grained prices in a single step rather than via subsequent splitting into more and more zones, several other measures can be incrementally introduced to prepare for the shift to LMPs, as well as to improve the efficiency in the current zonal system.

> An **increased use of intraday auctions** (see Section 4), up to real-time markets, can improve zonal markets in terms of liquidity, market power resilience, static allocation efficiency, and efficient usage of cross-zonal capacity.

> **Technology-specific multi-part bidding**, enabled by regular auctions, allow participants to fully express their capabilities to the market. This enables efficient integrated arbitrage over several time periods, increasing efficiency under uncertainty [221] and lowering participatory barriers for market participants.

> **Co-optimization of energy and ancillary services**, enabled by auctions and multi-part bidding, leverages efficiency improvements, as a simultaneous clearing allows market participants to allocate their capabilities to the best paying service, rather than needing to arbitrage in two sequential markets without the possibility for recourse.

> Shifting to **financial balancing groups**, instead of physical balancing groups, with corresponding adjustments of the imbalancing rules, can improve system stability without penalizing balancing responsible parties or favoring larger portfolios (see Section 3.1.1).

> Adjustments of the **MiFID II directive** and national implementations can allow for a broader participation of all market players in derivative trading for hedging purposes (under requirements of prudent risk management).

> Exploring how **TSO-DSO cooperation** can be coordinated **in an LMP system** as opposed to the current zonal system promises upsides in the long run. In addition to traditional analytical and computational approaches, this could also include the definition of test regions against a (virtual) wholesale power market design with locational pricing.

8.3 A pathway towards implementation

Figure 5 illustrates a pathway towards the implementation of LMPs in Germany. The proposed measures are separated between key steps to foster the introduction of LMPs and parallel accompanying policies that contribute to a future-proof market design.

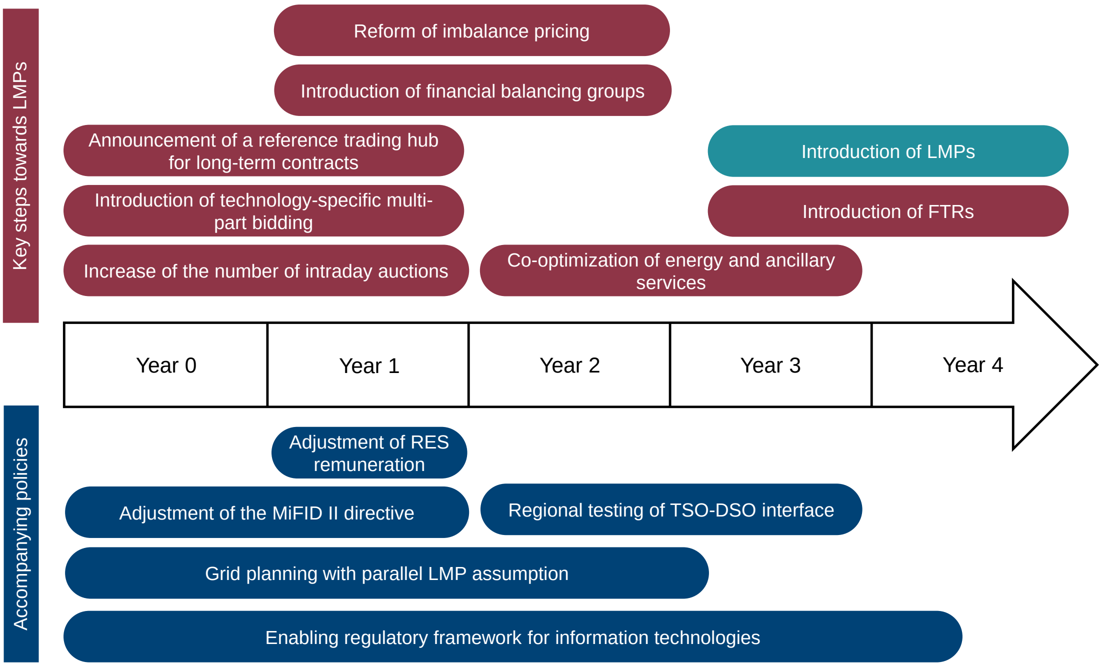

Figure 5: Pathway towards an implementation of LMPs

Starting in the reference year 0, an increased number of **intraday auctions** – jointly introduced on an EU level – would augment the current market design by providing transparent price signals and increasing liquidity. Technology-specific **multi-part bidding** paves the way for unit-based bidding and could build on existing multi-part bidding frameworks under EUPHEMIA (e.g., shifting from block bids to scalable complex orders). It seems reasonable to already announce that, in the event of a transition to LMPs, longer-term contracts will be referenced to a **trading hub** based on a load-weighted average German electricity price. Moreover, the adjustment of the **MiFID II directive** could be initiated to allow municipal utilities an effective hedging of (future) basis risks. The **grid planning** should take into account the transition to LMPs, and a consistent regulatory framework for the usage of **information technologies** could be facilitated. The following year 1 could involve an introduction of financial instead of physical balancing groups and a reform of **imbalance pricing** to enable unit-based balancing. The **remuneration of RES** could be adjusted in a way to prepare it for the transition to LMPs, e.g., as part of an EEG reform. The **co-optimization** of energy and ancillary services could be initiated in year 2, as well as regional testings of **functional interfaces between TSOs and DSOs**.

Finally, based on these preparatory measures, **LMPs** could be introduced along with **FTRs**. This final implementation should be based on preceding consultation phases between relevant stakeholders. Moreover, the technical development of robust clearing methods should be initiated earlier and aligned with European market coupling. Overall, the proposed pathway to implementation is ambitious and requires the cooperation of many stakeholders. Therefore, a timely and target-oriented transition to an LMP system can only be administered with **strong political support**.

In view of a rapid expansion of RES and likely scarcities of grid capacities, an implementation of an LMP system in Germany promises many upsides and can be a cornerstone for a sustainable electricity system, economic competitiveness, and a decarbonized economy and society. The transition to LMPs constitutes a complex undertaking, but a consistent and enabling market design paves the way for an economically and ecologically sustainable future with an affordable, reliable, and carbon-neutral supply of electricity.

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