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EU power market reform toward locational pricing: Rewarding flexible consumers for resolving transmission constraints

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ABSTRACT

The ongoing expansion of wind and solar electricity generation alongside increasing electrification is leading to a considerable strain on transmission capacities and grid bottlenecks in the EU. Coping with this challenge requires increasing system flexibility, e.g. by exploiting the potential for demand-side flexibility. However, in the current market design, demand-side flexibility responds to zonal price signals rather than local needs. As a result, demand-side flexibility may exacerbate rather than reduce congestion. More local price signals are therefore required. This paper assesses possible reform steps and their viability from the perspective of different market participants and the regulators. It reflects insights from European and international workshops and literature. With respect to reconfiguration of the pricing zones, both a moderate increase of granularity and high increase of granularity preceded by various reform steps are considered. As an alternative, a shift to nodal pricing is assessed. It is proposed that such a reform could be pursued, either by parallel reform steps in tandem across all EU countries, or as a sequential phase-in, preceded by nodal pricing implementation in pilot regions based on a regulatory sandbox approach.

1. Introduction

Electricity transmission capacity is facing unprecedented stress both from the increasing supply of wind and solar generation and from intensifying demand (electric vehicles, heat pumps, data centers, climate-neutral basic material production). Grid congestion, already present in several EU bidding zones,[6] will increase (Thomassen et al., 2024) despite planned grid investments exceeding EUR 584 billion (European Commission, 2023).

Flexibility in the electricity system from the storage of electricity,

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[6] This is already reported as a source of concern by the Agency for the Cooperation of Energy Regulators (ACER) in *Cross-zonal capacities and the 70 % margin available for cross-zonal electricity trade (MACZT),* 2023 Market Monitoring Report, ACER.

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heat, and of intermediary products from electricity intensive processes is an essential complement to systems with large shares of fluctuating renewables. This allows surplus electric energy to be transferred from periods of high production to other periods (Kondziella and Bruckner, 2016). Demand for distribution and transmission capacity can be reduced and congestion avoided if this occurs, not only at national level, but also within distribution grids and regions (Antonopoulos et al., 2022).

However, in the current power market design, a common wholesale price across zones implies that demand and supply are only balanced at the scale of large areas, typically countries. Flexibility options are operated according to the national price, rather than local needs; thus, potentially contributing to additional congestion rather than alleviating it. Without suitable price signals, it is difficult to impossible for transmission system operators (TSO) to ensure demand-side flexibility addresses local congestion needs, and it is not optimized for misleading wholesale price. This is due to, among other things, asymmetric information on opportunity costs and storage levels of flexible consumers, and the required monitoring capacity. Hence, there is a need to increase the granularity of zonal pricing to ensure that flexibility options obtain appropriate incentives to respond to local congestion needs and are rewarded for their service to the system (Victoria et al., 2019).

The level of granularity required is under debate. EU legislation (European Commission, 2015) states that structural congestion is to be avoided by reducing the size of price zones. Other studies suggest that nodal pricing1F should be implemented with prices that may differ, for example at each off-take point from the high-voltage grid (Ahunbay et al., 2021; Knorr et al., 2024).[7]

The bidding zone review[8] was set up to propose a refined zonal configuration. The review requires that member states implement an action plan to address structural congestion within bidding zones, ultimately by reducing the size of the bidding zone.[9] Their modeling shows that the size of zones must be reduced significantly to address structural congestion. However, they also find that this will severely reduce liquidity and competition in short-term markets within the smaller zones. Hence, TSOs could not agree on one zonal configuration that would suffice to address the policy objectives.

If the size of zones is to be reduced significantly, additional reforms would be required. They could comprise the combination of (i) a shift from physically current balancing groups, responsible for joint balancing (physical pooling), to individual responsibility combined with financial pooling; (ii) a replacement of complex bids for portfolio-based bidding with multi-part bid formats for unit-based bidding supported by financial pooling of portfolios; and (iii) intraday auctions closer to real time. Once these reforms are implemented, it will then also be possible to (iv) better integrate balancing and energy markets, e.g. jointly clear markets at or close to real time. The reforms, however, also require (v) enhanced cooperation or institutional integration of transmission system operation and power exchanges that currently hold separate responsibilities: TSOs are responsible for congestion management, ancillary services, and balancing markets, while the nominated electricity market operators (NEMOs, e.g. the power exchanges (PXs)) are responsible for market coupling at the day-ahead stage and the continuous market trading platform and intraday auctions.

These multiple reforms raise concerns about whether the reform steps can be agreed and implemented in a timely manner. Each reform involves adjustments to the respective framework guidelines and subsequently of the grid code, each involving consultations and complex decision processes among ACER involving national regulatory bodies, and the European Network Transmission System Operators for electricity and its member companies, followed by decisions of the European commission.

Hence, we propose an alternative approach to address the urgent needs of the power system: a shift to nodal pricing. It would jointly address congestion and system balancing needs. The concept is internationally well established and has long been treated as a possible long-term market design solution in Europe (Eicke and Schittekatte, 2022). What was once considered a long-term vision two decades ago has now become our present, driven by the large-scale deployment of renewables and the importance attributed to demand side flexibility. We aim to analyze and address the specific adjustments and restructurings necessary in the existing EU electricity market for a transition to a carbon-neutral energy supply and the associated industrial transformation. We discussed this issue at workshops of the Future Power Markets Platform organized by the co-authors of this publication in 2024.[10].

The subsequent discussion is qualitative in nature. We do not attempt quantitative modeling, as this has been a detailed topic of academic and industry research for decades, but provide a helicopter view of some relevant work in the area. There are various sources of efficiency losses resulting from zonal pricing, and each has attracted separate modeling efforts. Efficiency losses related to irrevocable short-term operational decisions (day-ahead unit commitment of slow-moving units) are treated in Aravena and Papavasiliou (2017) for the Central Western European Region. An econometric approach towards analyzing the short-term efficiency gains of nodal pricing in the Texas market is proposed in Triolo and Wolak (2022). The magnitude of redispatch costs for the German market is documented in early work by Kunz (2013) and since been frequently updated. Vivid policy debates have surrounded the efficiency implications of a potential transition of Great Britain to nodal pricing which was contemplated in the recent Net Zero Market Reform (Frontier Economics, 2022; Mann, 2022). Early reviews by Eto et al. (2005) and by Neuhoff and Boyd (2011) find that in PJM and ERCOT the savings in the first year after the shift to nodal pricing suffice to pay for the transition costs. They find savings at the same scale in other ISO regions but could not compare these to the costs of the transition. Triolo and Wolak (2022) confirm large savings at the scale of 3.9 % of operating costs for and Antonopoulos et al. (2020) qualitatively discuss further effects.

Inc-dec gaming is highlighted as a serious challenge of zonal pricing in Alaywan et al. (2004) early on in the US market design debate. Subsequent work by Holmberg and Lazarczyk (2015) points out that market power is not a prerequisite for inc-dec gaming, while the work of Lete et al. (2025) proposes a complementarity model for modeling zonal pricing equilibria with inc-dec gaming. The complementarity model proposed by Lete et al. (2025) further endogenizes investment decisions and is thus used for representing the difficulties that are faced by zonal pricing in terms of correctly locating new investments, with a numerical case study being conducted for the Central Western European region.

The paper is structured as follows: in section two, the case for further reform of the market design is demonstrated; in sections three and four of this report, the basic concepts are described, while sections five and six discuss more detailed design choices, followed by an exploration of a possible implementation pathway for the transition in section seven.

7 Nodal pricing accounts for transmission constraints in the day-ahead market, leading to price variations if congestion occurs. Producers are compensated based on the local price at their specific node (Sarfati et al. 2019).

8 Regulation (EU) 2019/943 of the European Parliament and the Council on the internal market for electricity requires a review of the bidding zones, which is pursued by ENTSO-E https://www.entsoe.eu/network_codes/bzr/

9 Regulation (EU) 2019/943 of the European Parliament and the Council on the internal market for electricity requires.

10 The initial workshop report which was the basis of this paper as well as reports on discussions on related topics are available at the website of the Future Power Markets Plattform https://www.diw.de/fpm.

2. Experience with zonal pricing for congestion management

Zonal pricing has historically evolved in the European Union from legacy regional monopolies. To allow third parties enter an incumbent dominated market, they were granted the right to trade at a common energy price within a pricing zone – typically determined by the geographical boundaries of a country. The incumbent players were mandated to facilitate all the resulting transactions. This principle was maintained also after vertical unbundling of the energy utilities. Market participants are free to nominate generation and demand schedules and trade within pricing zones, while the (now vertically unbundled) TSO is mandated to centrally redispatch generation assets to address potential violations of transmission constraints (Oggioni and Smeers, 2013).

2.1. Congestion management as an increasing challenge

EU energy market liberalization has gradually improved cross-border trading arrangements, in addition to opening internal markets within EU member states and the evolution of pricing zones (Newbery et al., 2016). With an increased diversification of energy sources, first by lifting earlier constraints on the use of natural gas for power generation, then with the increasing deployment of renewables, the value of cross-border trading also dramatically increased, requiring suitable trading arrangements. These arrangements had two objectives: first, to ensure a more flexible transmission capacity usage to contribute to efficient system operation and to enhance net-demand elasticity to mitigate market power. Second, to capture the value of scarce transmission capacity, and to use resulting congestion revenue to reduce network tariffs or support grid investment. These two objectives were addressed by the development of new day-ahead markets with a gradual shift toward implicit (joint) auctions for energy and transmission capacity in day-ahead market clearing; so-called market coupling.

With the large increase of wind and solar power generation, leading to significant levels of intrazonal congestion, the combination of zonal pricing with separate intrazonal congestion management schemes now reach their limits. For example, internal congestion can put pressure on transmission operators and national regulators to reduce transmission-capacity available for international transactions, as happened in the Svenska kraftnät case in 2010 (European Commission, 2010). Furthermore, the uncertainties of flow patterns within large pricing zones continue to result in uncertain loop-flows through networks of neighboring countries. This drives a need to increase reserve margins and therefore reduce the capacity available for trade. The concerns have triggered debates over market reform (Bindu et al., 2024) that are summarized in the next subsections.

2.2. Market segmentation by separate treatment of ancillary services and balancing

Currently, European TSOs are attempting to further integrate their balancing mechanisms, for both automated activation (PICASSO) and manual activation (MARI). These approaches make use of left-over cross-zonal capacity from intraday trading, which in turn allocates left-over capacity from day-ahead markets.[11] Without the ability to reallocate available transmission capacity across markets, cross-zonal balancing will remain constrained (Papavasiliou, 2020). As inefficiency and gaming opportunities increase with higher congestion levels this setup is hence not suitable as a basis for nodal pricing (or very small zones). Equally, the co-optimization of reserves for balancing and energy in the day-ahead market is required by the 2017 balancing regulation (European Commission, 2017), but implementation has not yet started. Again, co-optimization, including reserves, would reduce inefficiencies (Neuhoff et al., 2015a) that provide margins and gaming opportunities for large market participants.[12] Still, there are several key stakeholders, like large utilities, that have expressed their concerns about the implementation of co-optimization of energy and of reserves, arguing that its alleged benefits remain largely theoretical, while its implementation challenges, concerning the ability to compute the dispatch and prices in short-enough time, are already evident (Eurelectric, 2024). Other institutions argue that the efficiency gains computed in studies assessing the implementation of co-optimization are largely contingent on the parallel implementation of other changes to the market design, like unit-based bidding, which should be responsible for much of the alleged gains in scheduling efficiency (All NEMO Committee, 2024).

2.3. Fragmented markets and responsibility for core system functions

The EU has the institutional capabilities to mandate the integration of markets that are currently not fully exploited. Hence, for EU energy market integration, the development of independent power exchanges (PXs) was also prioritized and is now reflected in an entire EU governance structure for NEMOs. These are tasked with creating a Single Day-ahead Coupling (SDAC), i.e. a single pan- European cross-zonal day-ahead electricity market,[13] with similar developments for intraday markets.

Furthermore, transmission system operation was unbundled from vertically integrated utilities. TSOs in the EU are now responsible not just for operating balancing and ancillary services markets to procure reserve power but also for maintaining system stability (e.g. regional control centers) and frequency close to real time.

The strict separation of responsibility between some energy market segments (balancing, ancillary services) run by TSOs and other market segments with NEMOs (PXs) results in inefficiencies. Typically, energy and ancillary services are jointly provided by market participants, but auctions for both clear separately. This may explain the complexities and lack of transparency that result from attempts to find technical solutions to address the complementarities.

3. Learning from experience with nodal pricing for European congestion management

Across electricity markets in the USA, Mexico, New Zealand and parts of Canada, nodal pricing is a common market design.[14]

3.1. How does nodal pricing improve the electricity market?

Nodal pricing increases the granularity of the price signal. Nodal pricing systems typically calculate individual clearing prices for each node within the transmission grid. This ensures the market solution is also physically viable and avoids the need for subsequent re-dispatch. This is achieved because the clearing algorithm of spot energy markets considers all relevant transmission constraints. In principle, this resembles the flow-based market coupling, as implemented across the EU

[11] Market segmentation rather than joint clearing reduces liquidity and increase price volatility. In March 2023 Italy suspended operational participation in Picasso following extreme price volatility. https://timera- energy.com/blog/italy-suspends-picasso-afrr-platform-participation/

[12] Analysis suggests 1.3 billion euro annual efficiency gains for the core region https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_Cooptimisation_Benefits_Study_2024.pdf

[13] https://www.nemo-committee.eu

[14] PJM (https://www.pjm.com/), ERCOT (https://www.ercot.com/), CAISO (https://www.caiso.com/Pages/default.aspx), ISO-NE (https://www.iso-ne.com/), MISO (https://www.misoenergy.org/), Ontario, Canada (https://www.ieso.ca/), and for Alberta, Canada, nodal pricing was agreed in July 2025 (https://www.aeso.ca/), New Zealand (https://www.transpower.co.nz/system-operator), Mexico (https://www.gob.mx/cenace).

in the day-ahead market. But it uses the nodal instead of zonal level granularity and is applied not only to clearing at the day ahead but also up to real-time.

Trading of energy and of multiple balancing services is integrated in a real-time energy market. This is possible because the market result is not violating transmission constraints and there is no need to stop the market prior to real time to allow for redispatch. Real-time markets are cleared in five to 10-min intervals to allow for an efficient and secure operation of the system, which is coordinated through the real-time price and provides incentives for all market participants to address energy balancing and transmission needs. This avoids segmentation of the electricity market across different product types and for different time horizons with a variety of qualification requirements and complexities. This increases transparency, liquidity, and efficiency while reducing the potential for the exercise of market power.

3.2. How does nodal pricing affect market participants?

A change from zonal to nodal pricing affects market participants in multiple ways.

Forward markets: Most energy is traded in forward products,[15] both in zonal markets in Europe and in nodal pricing markets in other parts of the world. Instead of a zonal price, nodal pricing regimes use the price at trading hubs as reference point for forward contracting. They define the average price of a set of nodes in a geographical area. Trading volumes over specific market sessions typically match or exceed the volumes experienced in the corresponding EU zonal pricing market sessions (Neuhoff and Boyd, 2011).

Trading at the hub does not hedge market participants against the potential price difference between the hub and the nodal price of their power production or consumption (basis-risk). To provide a longer-term price hedge against this risk, electricity consumers and their retailers are typically issued financial transmission rights (FTRs; or auction revenue rights). These can then be traded. Liquidity of FTR trading is, for example in PJM, relatively high, but implementation must address various challenges (Eicke and Schittekatte, 2022). Market participants can also decide not to hedge the basis-risk and to only contract at the hub-price for risk management. This is similar to the situation in some European countries with insufficient liquidity in national forward markets: market participants hedge use more liquid exchanges in neighboring countries to hedge.

Day-ahead markets: Day-ahead markets are the short-term markets with the highest trading volume. In nodal, like in zonal pricing, market participants submit their bids to a common auction platform. The format of the bids, however, differs. In Europe's zonal pricing regime, market participants submit complex bids for an aggregated portfolio of units. In nodal pricing, market participants submit multi-part bids for larger units and can aggregate bids for smaller assets and demand-side resources. The auction results, in both settings, provide financially firm results.

In European zones with structural transmission constraints, large generators are required to nominate their production schedules at the day-ahead stage to facilitate effective congestion management. Also in nodal pricing systems, large generators are required to produce according to their bids accepted in day-ahead auctions – unless updates are coordinated with the market operator. All other market participants can in nodal pricing regimes deviate and pay the real-time price for their deviations.

The change of bidding format toward multi-part bids for individual assets simplifies market participation for smaller players and demand-side flexibility, because the bidding format allows them to nominate the precise capabilities of their physical assets (like start-up costs and ramping times). The current complex bidding format is more tailored to the needs of large trading and generation companies with internal pooling capabilities as it does not allow for a reflection of the full intertemporal constraints of individual units.[16]

Intraday: In existing nodal pricing markets, in the case of large dispatchable units, market participants can update or retain their unit-based bids after the day-ahead market. These updated bids are then used in subsequent stages of intraday market clearing. Thus, if for example wind or solar producers or the market operator anticipate changes in projected wind production, then in the intraday-clearing, the least-cost response options for production and demand is identified based on unit-based bids. The accepted bids are then communicated to the respective units in time for the necessary actions.

Real-time: The real-time market typically clears every 5–10 min and the clearing prices are directly communicated to all market participants. These prices provide incentives for all market participants to contribute to an energy balance that complies with the transmission constraints in the system. The market clearing considers the technical constraints of units, as nominated in their unit-based bids, and the evolving demand pattern in future time periods, to ensure the feasibility of the market result. All deviations of production or consumption from accepted bids from the day-ahead market or intraday clearing paid at this real-time price for the corresponding node and 5-to-10-min time slot.

As all market participants can respond to this real-time price signal, they all provide their flexibility to the system. The cumulative effect of many small actors can be predicted, using for example, demand elasticity estimates. For large units, this differs. If they were to only respond to the real-time price signal without any prior coordination, this could imply uncertainty at the GW-scale (instead of MW scale) and thus create challenges for system operation. Hence large units are expected to follow the results from the day-ahead or intraday clearing. Wind and solar power producers, for example in PJM[17] can nominate their availability at the day-ahead stage; subsequently, the system operator projects their expected production and considers this during market clearing.[18]

The real-time market provides incentives for all market participants to contribute to system balancing and, thus, can avoid the need for balancing markets and products (Frequency Containment Reserves (FCR) and Automatic Frequency Restoration Reserves (aFRR) are still needed, as are governor control and Automatic Generation Control (AGC) in the USA). As the real-time price signal has the same locational granularity as the day-ahead market, and results from a market clearing that fully reflects this granularity, the market result is physically feasible, and re-dispatch is not required.

4. Reform steps for a system wide transition from zonal pricing to nodal pricing

4.1. Bidding zone review to better address congestion

The current European electricity market design and network codes provide for zonal reconfiguration and splitting within a so-called bidding zone review. TSOs were mandated to propose a reconfiguration of

[15] Around 88 % of electricity transactions take place in the forward markets, according to EFET, the European Federation of Energy Traders: https://efet.org/files/docments/20220216%20EFET_Insight_01_forward_trading.pdf

[16] Further, in nodal pricing regimes, market participants can decide to self-schedule if they so desire and, thus, are typically not required to participate in the day-ahead auctions. They nominate their schedules which are then considered during the auction clearing. They are charged (or remunerated) for the transmission costs of their scheduled flows at the nodal price difference between entry and exit point.

[17] PJM is the electricity market for 14 northeastern US states https://www.pjm.com/about-pjm/who-we-are

[18] Also EU TSOs typically operate the system based on their own wind and solar forecasts as these are more precise and contain the necessary geographical granularity for congestion management.

bidding zones such that market clearing does not result in structural constraints.

However, a major concern raised by market participants is that smaller zones could result in reduced liquidity in spot markets. In the current setting of continuous intraday trading, market participants are often limited to transacting with partners within their bidding zone because (i) binding cross-zonal constraints imply that bids on the continuous intraday platform can only be matched with other bids within the same zone, and (ii) bilateral trade outside of the continuous intraday platform is inherently constrained to transactions with other partners in the same bidding zone. Thus, in the current context, reducing the size of bidding zones will reduce liquidity (Eicke and Schittekatte, 2022) in the intraday markets.

4.2. Three reform steps to ensure liquidity and competition with smaller bidding zones

With a combination of three reform steps, a subsequent reduction of the size of bidding zones would not jeopardize liquidity and competition in intraday markets. First, a shift from physical to financial balancing groups, second, the adjustment of the bidding format from complex to capability-based bids, and third, the use of intraday auctions close to real-time. Within the Future Power Markets Platform, these reform steps were analyzed over the last decade, the key insights are summarized here.

4.3. Shift from physical to financial balancing groups

European electricity markets have the unique feature of physical balancing groups. All generation and load of one market participant connected to one pricing zone is jointly responsible for submitting a balanced physical schedule for the bidding zone and is liable for penalty payments and potentially legal sanctions for imbalances.

Physical balancing groups date back to the early days of market liberalization, when vertically integrated utilities were required to grant access to new market entrants. To facilitate entry, new entrants were only required to submit a balanced schedule and had the privilege to ignore network topology. Vertically integrated incumbents were at the time required to facilitate the corresponding transactions.

The paradigm of physical balancing groups persists, even though its historic motivation is now outdated. It is sometimes justified based on the argument that a significant amount of energy in Europe is transacted bilaterally and only the residual amount is traded on exchanges. However, regulators require renewable generation to respond to short-term price signals irrespective of long-term hedges provided through renewable support mechanisms. Hence also other market participants should be full responsive to short-term price signals and bid their entire capacity into short-term markets.

4.4. Shift from complex bids to multi part bids

The complexity of current bids relates to the reflection of intertemporal dependencies in the bids, e.g. the ability to submit bids to offer or request energy for a block of pre-defined time (block based). Linking bids to specific units requires the use of multi-part bids reflecting start-up costs and generation unit constraints (Commission de régulation de l'énergie, 2023). Such multi-part bids are necessary to ensure market participants can continue to realize the benefits they currently attribute to portfolio bidding for intraday and other markets to offer flexibility to react to unfavorable outcomes of earlier market phases (All NEMO Committee, 2024) and thus realize efficiency increases (European Federation of Energy Traders, 2023).

Multi-part bidding helps level the playing field among smaller and larger players, as all can submit unit-based bids that reflect marginal costs and the physical capabilities of their assets in a uniform clearing price auction. Standing orders can also allow smaller players without a 24/7 trading floor to participate in the market. Smaller generation and load may only submit aggregate bids for assets at one network location.

Multi-part bids avoid the combinatorial challenge of clearing a market for complex bids – thus reducing clearing time and enhancing the reliability of the market outcome (currently it is impossible based on publicly available information to assess how close the clearing of Euphemia[19] is to an optimal market clearing outcome (Neuhoff et al., 2016)).

Unit-based bids are also helpful to monitor market power and apply market power mitigation (which is virtually impossible in portfolio-based bidding). This is of increasing importance with high shares of renewables, and thus the higher share of production with less predictable output. Thus, fossil assets have larger open positions in short-term markets.

4.5. The use of auctions close to real-time

The scale of transactions, not only day-ahead but also closer to real time, increases with the share of wind and solar power generation. However, intraday auctions are only used for the first hours of the intraday timeframe and only in a few countries. Transmission capacity that is freed up or that becomes valuable due to intraday changes in wind and solar projections continues to be allocated during intraday on a first-come-first-serve basis, i.e. for free, and thus possibly rather inefficient and with significant scarcity rent transfers to the largest traders with the best information. This again also implies possible inter-temporal gaming: traders active on both sides of one border might have an incentive to "move" trades from day-ahead, where they also must pay for cross-border transmission capacity, to intra-day, where a substantial amount of this capacity is allocated for free.

Instead, trading closer to real time would need to be shifted from bilateral trading to auctions to ensure that cross-zonal transmission is allocated efficiently and scarcity rents for transmission capacity are captured to reduce network tariffs for consumers (Neuhoff et al., 2015b). So far, the increased use of intraday auctions is, however, inhibited by the concern that it interrupts continuous intraday trading. It is also argued that requiring continuous intraday trading will allow for adjustments in positions and schedules that intraday auctions would struggle to facilitate because they (currently) only comprise energy only bids that do not allow generation companies to offer their full flexibility (Bindu et al., 2023).

A shift to unit-based multi-part bids would, in turn, overcome these constraints and ensure that market participants can offer their full flexibility to intraday auctions and allow for the use of auctions throughout the intraday period.

4.6. Synergies across the reforms

The discussion illustrates that a shift to financial pooling instead of physical balancing groups would facilitate a shift to multi-part bids and the full use of intraday auctions. The clearing of intraday auctions considering energy and transmission constraints would, in turn, ensure that, even with smaller pricing zones (even reduced to nodes), the full liquidity of short-term bids across the system can be considered.[20]

This would then also allow abandoning imbalance penalties currently levied on deviations from submitted schedules with their discriminatory effect against smaller actors (Neuhoff, 2015). This is because unit-based bids result in incentive-compatible generation and load schedules that enhance the granularity and robustness of information available to TSOs. Financial pooling across assets would still offer the same risk management to market participants as physical

[19] EUPHEMIA stands for EU + Pan-European Hybrid Electricity Market Integration Algorithm.

[20] We discuss the implications for forward markets in Section 3.2.

balancing groups. Thus, participants with purely competitive interests would not be disadvantaged.

One major concern of stakeholders opposing the implementation of nodal pricing, or smaller bidding zones, may relate to the fact that unit-based bidding complementing nodal pricing enhances the revelation of information (Bertsch, 2024) and thus also allows for effective market power monitoring and mitigation measures (Eicke and Schittekatte, 2022; Antonopoulos et al., 2020). The absent ability to monitor dominant (incumbent) market agents exercise of market power is increasing in relevance due to an increasing variance of production by conventional generation capacity in response to the variations in wind and solar output. It implies that the forward contracting coverage is declining and thus the market power mitigating effect of forward contracts is declining (Allaz and Vila, 1993). Therefore, there are large concerns relating to market power that can be exercised in short-term markets. There are further concerns that large companies could adjust the production schedules of generation (e.g. schedule maintenance or increase output) or schedule international transactions to escalate congestion and therefore re-dispatch needs and then profit from the margins if they are dispatched down. All these concerns can only realistically be monitored, identified, and thus limited, with unit-based bidding and integration of the different market segments (timeframes) as is common practice within nodal pricing regimes.

Opportunities to improve EU power market design with the goal of achieving a better reflection of geographical and temporal constraints were discussed between 2013 and 2019 by the European partners of the *Future Power Market platform* (FPM) and workshop participants. They were subsequently reflected in a longer-term vision for a fully integrated European approach, with underlying motivation reflected in the *SynErgie Whitepaper I* (Ashour Novirdoust et al., 2021), while the pathway toward this result is summarized in *SynErgie Whitepaper II* (Ashour Novirdoust et al., 2021).

The main challenge for such a transition at European scale may reside in the current governance structures of decision making on grid codes. These challenges are compounded because of conflicting interests of stakeholders (Ragosa, 2024). The experience of rather slow progress raises the question of how long it might take to implement the sequence of the outlined steps.

5. Design choices in nodal pricing: the North American experience

In North America nodal pricing was implemented at the geographic scale of regional markets, typically comprising one or several states. This section explores some of the insights from this experience.

5.1. The relationship between TSOs and power exchanges

The first implementation of nodal pricing in the US was within regional control centers, which are responsible for operating power systems throughout the geographical coverage of multiple utilities and (in the case of PJM) states. These are independent from individual utilities (hence the name independent system operator – ISO) and gradually added the commercial capabilities to their existing technical expertise.

In the EU, PXs and TSOs are reluctant to engage in structural changes, probably because of the uncertain implications for future scale, type, and location of jobs. Institutional competition – e.g. power exchanges and TSOs competing for the “opportunity” to implement and host the integrated functionality – did not emerge.

Therefore, it may be more promising to consider options for increased cooperation to bring together the complementary capabilities of TSOs and PXs while ensuring continuity of operation and avoiding career risks. This could enhance support for an effective and timely reform.

5.2. The regional scope of nodal pricing

A one-off shift from the current zonal pricing system to merge all system and market responsibility with one centralized institution would imply significant political, regulatory, administrative, and commercial complexity.[21] Questions are also raised about whether such a centralized approach would address the interests of all member states and sparked debates on the suitable country for its location.

Therefore, it may be more viable to focus on the introduction of nodal pricing at the regional level, e.g. at the scale of countries or groups of countries. This could build on the pragmatic North American approach and successful EU power market reforms for example of balancing markets.

It is equally important to consider a longer-term perspective that does not involve concentrating all market clearing at one central location, instead retaining a more decentralized structure with market clearing at the scale of countries or groups of European countries. This could be more in line with the subsidiarity principle by retaining power in the regions, thus facilitating the addressing of system and cyber security concerns.

However, this raises the so-called “seam issues” – concerns that incomplete cooperation between nodal pricing regions limits effective congestion and market integration. This was two decades ago one of the major concerns for nodal pricing in North America. Initially, improvement seemed impossible, as ISOs responsible for each market region had little interest in cooperating with other ISOs, as they feared the risk of decision power and influence could migrate to the cooperating ISO. These concerns later vanished, as ISOs had reached, through organic growth of their market regions, a scale that could no longer be increased due to limited capacity of staff in any one control center to oversee the secure system operation. Thus, enhanced cooperation between ISOs no longer created risks of ISO-mergers and job losses, and effective solutions for enhanced cooperation to address the “seams-issue”.

In 2022, during a joint EU-US workshop to assess the costs and market design responses to the seams issue, it was intriguing that US experts had no current experience with “seams-issues”, it had long since been resolved in the United States and it was for them a relic of the past. This experience suggests that it is possible to operate nodal prices at the regional level in Europe and in parallel further enhance the integration of the common European electricity market.

5.3. Management of interfaces between regions with nodal pricing

In the **Eastern Interconnected system in the US**, the two largest ISOs - PJM and MISO – were both established based on political choices and not consideration of network topology. Hence, effectively they are operating the same closely meshed network. Joint congestion management has been pursued based on such systems since 2004.

For critical interfaces, the amount of capacity split between local and adjacent ISO (entitlements) use is defined. After each clearing of the real-time market by the ISOs (every 5 min) a joint shadow price for these critical interfaces is determined. Thus, in the next clearing, the value of the critical interface for use by the adjacent ISO will be considered to ensure efficient use of scarce transmission capacity. Deviations from flows from the previous entitlements are then remunerated between the ISOs at the shadow price.

An alternative option to consider is implemented at the interface between the US southeast – without vertically integrated utilities and nodal pricing – and PJM – which uses nodal pricing. Like the current EU situation, flow entitlements on critical lines are defined for the respective parties. Each party is then required to stay within these entitlements. For this, they rely on approximate modeling for loop-flows.

[21] For a review of the main literature, please refer to Eicke and Schittekatte (2022) Section 4.5 “Complexity.”

In the **Western Interconnected System in the US, the California-ISO (CAISO)** implemented a full network model for the entire West to get a better sense of loop flows. With the Western Imbalance Market (WEIM), which is a real-time market, energy and transmission are now jointly cleared for most of the West, based on nodal pricing. Resource adequacy and ancillary services decisions remain with member balancing authorities (approximately 20).

The US experience shows that effective cooperation between adjacent ISOs in meshed grid systems is possible using a largely standardized approach, the basis of which is reflected in early academic work (Cadwalader et al., 1999).

6. Introducing nodal pricing – starting in pilot regions

In this section we explore how individual countries or groups of countries could implement nodal pricing. By providing a blueprint, these pioneering regions could then serve as examples for other Member States.

6.1. Motivation for countries to implement nodal pricing pilot

What are the opportunities and challenges for individual countries or groups of countries that may decide to pilot nodal pricing? Italy has implemented both zonal prices within the country and is using nodal pricing for real-time dispatch within respective zones; although these do not apply to demand, which is still subject to zonal pricing (Oggioni and Lanfranconi, 2015). This requires the use of unit-based, multi-part bids. The implementation of nodal pricing across all timeframes would allow for a more consistent and effective implementation of intraday and balancing market clearing by addressing constraints currently imposed by EU regulatory requirements.

Poland has also implemented an energy market based on multi-part bids from each generation unit. These offers are used for unit dispatch, which is locationally specific. In parallel, a zonal price is calculated, at which all generation and load are remunerated (unless costs of units that are dispatched centrally exceed this price, in which case their cost is covered) (Siewierski, 2015). The country had already envisaged shifting to nodal pricing for real-time market clearing, with a vision of gradually expanding the coverage toward day-ahead market. It procured the corresponding software in a competitive tender from three globally established providers of nodal pricing software engines.

6.2. What flexibility do countries require for implementing a nodal pricing pilot?

The national experiences point to potential challenges for implementing nodal pricing at the regional level. Although the third energy package – alongside the network and grid codes developed based on this package – ensured that sufficient flexibility is provided for individual countries to advance locational pricing, this flexibility was apparently lost with the introduction of the fourth energy package. In particular, the artificial but mandatory differentiation between balancing actions and congestion management actions in the fourth energy package is contrary to physical reality. Nodal pricing, however, correctly reflects the physical reality also in real-time markets that jointly clear energy, balancing, and congestion management. It must reflect this physical reality, because the value of any kind of product whose delivery is constrained by the network must be locationally differentiated, potentially up to the nodal level.

A regulatory sand-box provision would be required in network and grid codes to improve the ability of pilot regions to implement nodal pricing. Pilot regions could be granted the flexibility to not participate in the joint balancing arrangements. This would allow for real-time pricing to work effectively within the nodal pricing market region. Opportunities for enhanced integration at intraday stage could also be created by introducing intraday auctions in zonal pricing regions not only after the day-ahead auction but throughout the entire intraday period. In contrast to continuous trading, such auctions could offer an interface to interact with auction clearing in the nodal pricing market region.

Thus, if pilot regions were to obtain a set of exemptions from the current regulatory framework prescribing a full separation of markets for energy, redispatch, as well as ancillary services and balancing, then they could pursue another attempt to implement nodal pricing.

6.3. How would markets between nodal pricing and other regions be integrated?

Although different approaches, some geared toward the coupling of nodal and zonal systems, were previously discussed (Richstein et al., 2018), the various trade-offs still need to be better understood.

6.3.1. Joint clearing of pilot regions with Euphemia

In theory, one could envisage that a pilot region could implement nodal pricing and clearing within the Euphemia algorithm. In practice, however, the algorithm already seems to struggle with current requirements (Eicke and Schittekatte, 2022) and it seems unlikely that fast implementation and robust operation are possible for the engine if it were to also host a market region with nodal pricing. A transition to non-uniform pricing and dropping pricing rules that couple the prices and quantities cleared (primal and dual variables) would nevertheless likely be a significant step forward in overcoming this problem (Market Coupling Steering Committee, 2023). The principal issue here is not the algorithm, but the institutional resistance to such changes in bidding product specifications.

Furthermore, Euphemia is only operating at the day-ahead and, since recently, intraday timeframes. It would not be suitable for clearing a real-time market that jointly clears energy/balancing and transmission capacity. This joint clearing, however, is at the core of nodal pricing as it ensures that all resources can contribute to balancing the system. To avoid gaming, one must ensure that real-time market balancing is pursued consistently with intraday- and day-ahead timeframes. Large-scale institutional and computational developments are necessary before Euphemia (or a follow-up clearing algorithm and design) can accommodate nodal pricing.

6.3.2. Separate clearing in pilot regions

Alternatively, market clearing in the nodal pricing pilot country/region could be separate from the market clearing of market coupling in the remaining EU energy market. This would then require rules to ensure loop flows are appropriately reflected and to facilitate trade.

To address loop flows between neighboring market regions, experiences from the USA and EU provide a consistent blueprint. In the USA, whenever market regions operated by different ISOs are linked, transmission lines carrying significant (loop) flows from both regions are identified and shadow prices for their usage are used to prioritize access and remunerate mutual use (see Section 5.3). This is equivalent to the critical interfaces concept used for flow-based market coupling in the EU. A common approach should therefore be possible, building on EU practices.

The main question is therefore how to define the trading arrangements at the interfaces between a zonal and a nodal market region to ensure trade will not violate transmission constraints. There are three basic options.

6.3.2.1. Pre-screening of bids or nominations from pilot regions. The market operator in a nodal pricing regime could be mandated to pre-screen bids or nominations for auctions in neighboring countries. Only bids or nominations that would not result in additional congestion would then be allowed. Given network complexity, some congestion levels are always present and, hence, in practice, threshold levels would need to be defined and used. Pre-screening of bids would normally result in efficiency losses in exchange for simplicity of implementation.

6.3.2.2. Charging for congestion costs (ex-post). Nodal pricing regimes already allow for bilateral transactions within the regime. Parties then pay a transmission charge defined by the difference of local prices between origin and destination of the transaction. Equivalently, the nodal price differences could be levied on cross-zonal transmission. Various options to define the relevant reference points have been discussed. A challenge for such trades is that congestion costs are only fully known in real time, e.g. after the trade, imposing a certain amount of risk. Given that transactions in the nodal region are already implicitly paying for the use of the scarce transmission capacity within this region, the additional charge would only concern the market value of the scarce capacity in neighboring zonal pricing regions.

6.3.2.3. An aggregate net-export function from pilot regions. An aggregate net-export function, calculated by the market operator of the nodal pricing regime, could be submitted to day-ahead and possibly intraday auctions in the neighboring market regions. In simplified terms, the market operator would consider for the auction clearing different volumes of imports or exports from the neighboring market regions. This provides for a simple net-export function – a set of price and quantity pairs for net-exports given different price levels. This is proposed in the context of real-time market clearing on the MARI pan-European balancing platform (Papavasiliou et al., 2022) and explored by Norwegian TSO Statnett.

A set of questions emerge relating to the detailed implementation of such an aggregate net export function. First, how to precisely reflect intertemporal dependencies? The net-export function would need to be calculated for all combinations of export volumes in each of the 24 h (or even shorter time periods) of a day. Pragmatic simplification is required, for example abstracting from individual unit commitment choices for market region trade. The larger the pilot region, the smaller the importance of such individual unit commitment choices. Second, in Europe, some potential pilot countries or sets of countries may have important interfaces to multiple adjacent bidding zones. How to calculate separate but interdependent net-export functions to be submitted to the different NEMOs in the different adjacent zones? These would then be jointly cleared under the EU market coupling. Some heuristic would likely be required to share the net-export function quantities to these adjacent zones.

All three trading arrangements at the interfaces between a zonal and a nodal market region would need to be considered for application at day-ahead, intraday, and balancing timeframes. Ultimately, discussions suggest (i) that pragmatic solutions for the day-ahead market are necessary and possible; (ii) that, although complex, facilitating an effective market coupling between pilot regions and the rest of Europe at intraday stage is helpful; and (iii) that integrating balanced markets in the existing regime might prove challenging.

6.4. What is the optimal scale of a pilot region?

Under the 70 % rule in the clean energy market package (Directorate-General for Energy, 2019) – that requires granting preferential access for cross-zonal transactions to "internal" critical interfaces – countries will benefit from implementing smaller zones or nodal pricing, as this allows them to get full access to all transmission capacity. So, in principle, this would be an incentive for moving to nodal pricing (if the 70 % rule will be strictly enforced without exceptions by 2025).

If market integration between a nodal pricing region and adjacent regions is slightly weaker than within a nodal pricing region (or even within existing zonal pricing regions), then it would be desirable to have market regions that correspond to strongly interconnected parts of the system. Interfaces of the border should reflect network congestion, which may not necessarily be aligned with the geographical boundaries of countries.

Theoretically, this could follow the flow-based market coupling process experience – with an increasing number of countries implementing the approach initially only pursued in northwestern Europe. Alternatively, developments could emerge in parallel. Such regional developments could be anchored in regional coordination centers or according to the (different) geographical scope of capacity calculation regions. Importantly, successful integration will benefit from the self-selection of countries to cooperate.

7. Conclusions and policy implications

EU power market design has largely evolved with a vision of large-scale generation assets serving the needs of inflexible demand. Now the rapid increase of wind and solar power generation and the fast rise in requests for grid access of storage, heat pumps (electrification of heating), and electrified industrial production processes is dramatically changing this vision. Generation capacity and connected loads are multiplying alongside congestion in the transmission and distribution systems. Grid investment alone is clearly insufficient to address this challenge. Hence, reforming the market design to allow for an efficient use of demand-side flexibility and storage, not only for energy balancing but also to avoid and manage congestion, is necessary and could offer multiple benefits.

First, it would reduce redispatch costs and, thus, consumer network charges: increasing congestion levels result in increasing redispatch needs within large pricing zones, if flexible loads only respond to average zonal prices. Local prices – from small pricing zones or nodal pricing – give a clear signal to both entrepreneurs and consumers to exploit their demand responsiveness, e.g., invest in and use flexibility from electric vehicle batteries, heat storage, and intermediary product storage to allow electrified industrial processes to respond to the needs of the local grid.

Second, it would realize benefits of a pan-EU energy system for consumers by allowing demand-side-flexibility to contribute to effective congestion management and predictable flows – thereby enhancing the network capacity available for pan-EU energy transactions.

Third, it would bring the market closer to and engage consumers: responding to increasing scale of network congestion, regulators implement measures to curtail load during peak demand periods and create incentives for constructing behind-the-meter batteries and flexibility elements to smooth PV feed-in. This may alienate market participants from energy markets, encouraging more autarchy-oriented management of storage and flexible demand. More granular pricing can avoid the need for such market interventions, instead encouraging consumers to respond to pricing at the relevant off-take node from the transmission network (e.g. city electricity price), thus helping to avoid transmission and distribution congestion. It also increases the attractiveness of engaging with the (local) market rather than operating household-level or small-business energy systems largely disconnected from market signals.

Fourth, it would avoid distortions and create a level playing field for EU consumers: currently, dispatchable assets can sell power at the zonal price, even if it exceeds the real value of electricity at their location. The TSO must then centrally redispatch the system to ensure network security. This can include mandating generators in export-constrained areas to not produce while procuring energy at other locations. As most congestion is structural, e.g. predictable, market participants can adapt their bidding, this aggravating the issue and associated redispatch costs. The redispatched generators are only charged according to their avoided variable costs (in case of regulated redispatch) or based on their offers (in case of redispatch markets) for energy not delivered and thus can retain the profit margins from initially selling at the zonal price exceeding their variable costs. Consequently, large pricing zones increase costs for domestic consumers and profitability of domestic conventional generation – distorting the EU level playing field and transferring wealth from consumers to producers.

Fifth, it would reduce costs for consumers by better monitoring and mitigation of market power. The current practice of portfolio-based bidding within large bidding zones alongside the segmentation of markets for energy and different reserve products limits the ability not just for market surveillance but also to monitor and identify the exercise of market power by companies with portfolios of conventional generation assets.

Sixth, it would reduce regulatory and investment risks while further reducing costs for consumers: The bidding zone review, its extensive delays, and court cases related to transmission capacity-related decisions already initiated by Member States, have alerted all investors to the fact that potential zonal reconfigurations can be subject to large regulatory interference and uncertainties. Because it is inherently difficult to anticipate the geographical outcome and price impact of zonal reconfiguration, investors will apply risk mark-ups and premia, potentially exercising the option value of waiting for more regulatory clarity. A clear and long-term viable decision on locational or zonal pricing is urgently needed to provide investors with the necessary confidence in the regulatory setting to direct their investments in the most appropriate location in the grid. This includes elements that address locational risks for vulnerable consumers and investors; e.g., with a renewable energy pool that hedges the price level at the location of renewable generation and of load.

A set of challenges remain, that must be addressed in any reform: First, although increased operational efficiency will bring reduced average electricity costs for most consumers – dependent on the location-some consumers may be affected by cost increases. Thus, parallel financial hedging might be needed (as is common in North America). Second, since there is not yet consensus and shared understanding of the policy options, concerns about the complexity of any changes persist. Thus, design options and pathways require more attention. Third, the multitude of ongoing reform processes and policy interventions at both national and European level – including ad-hoc measures to address network congestion – occupies regulatory capacity. Structural solutions that are also longer-term robust should be prioritized.

CRediT authorship contribution statement

Karsten Neuhoff: Writing – original draft, Conceptualization. **Franziska Klaucke:** Writing – review & editing, Writing – original draft. **Luis Olmos:** Writing – review & editing, Writing – original draft, Conceptualization. **Lisa Ryan:** Writing – review & editing, Writing – original draft, Conceptualization. **Silvia Vitiello:** Writing – review & editing, Writing – original draft, Conceptualization. **Anthony Papavasiliou:** Writing – review & editing, Writing – original draft, Conceptualization. **Konstantin Staschus:** Writing – review & editing, Writing – original draft, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

No data was used for the research described in the article.

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