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Report

Local Market Places: Market design options

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Results of a Workshop of the Future Power Markets Platform (FPM), Brussels, July 2nd, 2025

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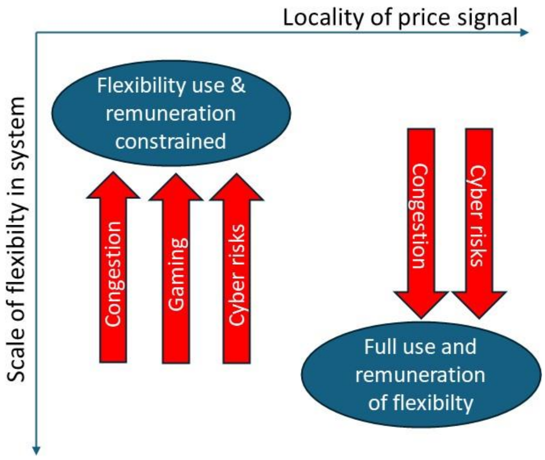
1. Motivation

As the share of renewables in power generation increases, the system needs greater flexibility to ensure that wind and solar energy, which might otherwise be curtailed due to mismatches in time and location of supply and demand, can be stored or transmitted to where and when they are needed or most valuable.

Local market prices are essential to make use of demand side flexibility and storage. At times and locations of high renewable production, the prices tend to be low, and heat, hydro, battery and intermediary product storage can be filled. Vice versa, in periods of low renewable production, the stored energy can be released. As local market prices encourage market participants to behave consistently with system needs, they increase predictability of flow patterns and thus require lower security margins to reach the same level of system security. The increased network utilization allows for increased pooling and sharing of flexibility across regions.



Without local market prices, demand side flexibility is of less help to the system:

1. High wind and solar production will be absorbed by storage across the entire zone rather than at the locations of surplus generation, even if there is insufficient transmission capacity to transport this energy. Demand side flexibility can thus rather escalate than address congestion, further increasing the amount of energy that needs to be redispatched. This further distorts prices faced by most resources, which could create additional gaming incentives and could lead to a further misalignment of the location of flexible resources with system needs.
2. System operators might use flexibility markets to solicit demand response to resolve congestion. But in the case of structural congestion, e.g. predictable opportunities in flexibility markets, market participants may game the system by mis-specifying their initial baseline

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demand to then increase opportunities in the flexibility market. This further escalates rather than reduces congestion. With local market prices that account for congestion in the clearing, demand side flexibility is fully rewarded through the energy price (implicit flexibility) and baselines are not required to define and remunerate explicit flexibility.

3. To solicit and accept bids for demand side flexibility in flexibility markets, system operators and aggregators typically communicate via internet with final consumers. As the scale of demand side flexibility managed through the internet increases, the security of the electricity system depends on the availability and security of the internet. To enhance resilience to technical failures and cyber risks, system operators may put limits to the scale of demand side flexibility that can operate in the market.

These three reasons imply that structural congestion within large pricing zones under the current market design will reduce the value and remuneration of demand side flexibility and may even create barriers for its realization. For example, investors in batteries are already concerned that they will not be granted grid connections to operate in the energy market.

In large pricing zones, two plausible approaches remain to unlock specific segments of flexibility:

- Flexibility technologies can be connected to the grid if it is directly dispatched by the system operator, rather than in response to wholesale markets. However, this seems plausible only for large-scale batteries. As these batteries would be operated outside of the market, they would also not participate in the forward markets and thus not help consumers to hedge their profile risks. Beyond batteries, such central control is difficult to imagine for other demand side flexibility options more deeply embedded in the energy systems of consumers.
- Consumers can individually or as part of energy sharing groups invest in their own flexibility/storage options behind the meter or within their sharing network. They can strive to reach electricity autarky. This does, however, pose risks for remaining customers that must bear the fixed costs of distribution and transmission networks. Autarky behavior also limits the volume of renewables and flexibility available to the system and thus increases the costs of energy provision to other users.[2]

In summary, we find that without sufficient local market price signals, the utilization, remuneration, and thus realization of demand side flexibility will decline, and demand side flexibility could even be detrimental to system efficiency and security. This implies that, at times of low production of wind and solar power, larger shares of energy demand may have to be served with dispatchable generation, such as coal, gas and potentially hydrogen. Energy costs and most likely also emissions would, as a result, increase. The import of larger shares of energy for different carriers also increases exposure towards energy cost and geopolitical risks.

[2] Appropriate network tariff designs should be put in place preventing local energy communities (LECs) and individual users striving for autarky from achieving a reduction in the share of the cost of already existing infrastructure, deployed long-before they have started applying this strategy, that they must pay. Besides, the supply security benefits obtained by those agents following this strategy should result in their having to pay a fraction of common infrastructure under any kind of circumstance (unless they permanently disconnect form the grid).

2. Is it sufficient to reduce the scale of pricing zones?

EU power market design is guided by the philosophy of a target model comprising pricing zones. These zones, typically reflecting national borders, were large enough to define balancing responsible parties that physically pool their supply and demand within a pricing zone. Transmission system operators (TSOs) delegate part of the responsibility for system balancing to these balancing responsible parties by a combination of the structure of imbalance pricing and mandatory requirements for balanced schedules.

This philosophy of large pricing zones is now embedded in grid codes. These dictate the consideration of a gate closure time prior to real time to provide for sufficient time for the TSOs to correct for the mis-specified market outcome by centrally redispatching the power system.

In the bidding zone review the TSOs faced the dilemma of the target model.

Large pricing zones are inadequate for effective congestion management. One response is to reduce the size of bidding zones. The main surprise of the bidding zone review was, that it did not limit itself to exploring for example splitting Germany into two or three, but also a five-fold zonal split. However, even in that scenario intra-zonal congestion remains significant.

However, the TSOs responsible for the report did not recommend such small zones and pointed out the risk of reduced liquidity and increased local market power that would result from smaller bidding zones. This is a result of the continuous intraday market which allows for cross-zonal transactions only as long as there is surplus capacity on all relevant critical interfaces required for the transaction. With most available capacity rapidly captured by traders that want to obtain access to the resource handed out for free in the continuous market, cross-zonal transactions are largely constrained, and all liquidity and competition is constrained to actors within a pricing zone.

One option advocated by various actors to overcome this dilemma is to build large amounts of grid capacity, thus reducing intra-zonal congestion and allowing for sufficiently large zones to be viable. This would, however, require extreme amounts of grid investments and imply extreme financial and diverse environmental costs for consumers and citizens. This is because the utilization rate of this grid would be relatively low, considering the low number of full load hours of about 2000-3000 (wind) and 1000 (solar) out of 8760 hours per year, but also the large volatility of demand for heating and electromobility.

The dilemma can be resolved with location marginal pricing.

The dilemma of pricing zones raises the following question: Is it possible to make pricing zones so small that market outcomes will not result in structural congestion? If it would be the case, then:

- redispatch to resolve such congestion is not necessary. This, in turn, avoids the need for gate closure prior to real time. Instead, market participants can respond to the market price signal until real time (e.g. until just before a five-minute market time unit).
- such a real-time market, as well as the preceding markets like day-ahead, can then be jointly cleared across many local marketplaces while respecting the constraints on available transmission capacity. This maximizes liquidity and competition across the entire system.

This is the basis of locational marginal pricing, the dominant market design in liberalized energy markets outside of Europe. However, the adoption of this approach has been facing strong resistance for reasons that have been changing over time. At the workshop, we discussed three main concerns on the implementation and operation of local marketplaces relating to the integration of consumers, the possibility of piloting, and the hedging of locational price risks. We also discussed potential solutions.

3. How to put consumer interests at the heart of the reform?

The EU power market design has historically been shaped around the needs and interests of the energy sector. A reform that aims to unlock demand side flexibility necessarily must start from the perspective of the consumer.

It can build on the success of energy sharing and local flexibility markets in engaging consumers and unlocking their flexibility.

- Local Flex Platforms have successfully engaged final consumers across Europe to offer their flexibility.
- Energy sharing concepts succeed in producing financial incentives, in terms of reduced grid charges, to engage final consumers to invest and operate flexibility.

So far, however, both approaches are not integrated but explicitly separated from the energy market.

- In local flexibility markets a baseline defines how much electricity a consumer would have traded in the absence of the local flexibility market. The consumer can make offers in the flexibility market to adjust production, usage and storage relative to this baseline. The fundamental challenge remains, however, the definition of a baseline.
- Energy sharing concepts are incentivized to operate in autarky from the energy market to save grid charges, rather than to benefit their members and the broader system by making flexibility fully available in the energy market.

Local market prices will integrate the consumers into the electricity market using the experience from local flexibility platforms and energy sharing concepts.

- Local flexibility markets can directly quote the local market price to the energy demand or provision of a customer and thus avoid the need for a baseline for consumption and risks of gaming this baseline in case of structural congestion. To clarify this progress, we refer to this next generation of local flexibility markets as local market platforms.
- Energy sharing concepts can improve the value for their members by optimizing the operation of their flexibility assets in line with the local market price. Thus, flexibility is also shared with the larger community and contributes to system needs. Meanwhile, it obtains remuneration for this, further enhancing the viability of the sharing concept for the consumers groups.

Thus, local marketplaces will increase the scale of flexibility available in the overall energy system and thus also benefit consumers not directly participating in these marketplaces. Local marketplaces will also provide a transparent interface (e.g. the local market price of cities or rural regions) to enhance the engagement and support for the overall energy market.

4. How is energy traded between local marketplaces?

What are the requirements for the backbone that provides the commercial and electrical linkage between these local marketplaces?

European experience from day-ahead market coupling has shown that local marketplaces must be cleared simultaneously while considering available transmission capacity between the marketplaces.

Hence, in principle one might envisage that the backbone could be provided by the zonal market clearing model if the zonal resolution is sufficiently increased to avoid congestion within a zone. However, the current zonal clearing is based on bids that do not reflect individual assets and their characteristics but complex bids that reflect trading interests of market participants. This artificially created complexity inhibits rapid market clearing close to real time. It also results in market outcomes that can imply large jumps of generation and storage output between individual trading periods, historically caused by large generation assets. This problem will escalate with the diverse storage devices that can ramp up or down even more rapidly.

How can the clearing algorithm incorporate the ramping constraints of large assets and allow for the definition of ramping limits for new flexibility providers?

- **Stepwise reform of EU market clearing approach:** The partners of the Future Power Market Platform have explored the necessary steps in many technical workshops over the last decade (see previous FPM reports at www.diw.de\fpm). Each of the various adjustments of the bidding format, reserve markets, additional intraday auctions offer opportunities to enhance transparency, competition and market efficiency and thus reduce gaming opportunities that benefited individual actor groups. However, it can also result in changes of relative prices leading to distributional debates, thus triggering further opposition. Finally, it involves technically complex discussions that need to be resolved in a consensual manner according to EU grid code, not least because policy makers will struggle to impose solutions. Workshop participants were shocked to learn that what might seem for external actors to be small adjustments within the current EU target model relating to joint congestion management and balancing market integration are delayed by more than a decade and unlikely to be concluded before 2030.
- **Use readily available solution** for an efficient and secure operation of the commercial and electrical backbone for local marketplaces. Clearing algorithms for locational marginal pricing with security constrained unit commitment have been implemented in many liberalized electricity markets outside of Europe and are provided by vendors with strong European roots as "off-the-shelf" solutions. To address the prejudice often voiced in the European context that such approaches are theoretically desirable but practically not feasible, the preceding FPM webinar allowed key actors involved in a transition from zonal pricing to locational marginal pricing in North America to report on their first-hand experience (available online https://youtu.be/YYBoG0vAMRA?si=OIjrN5-H1E_Gc654).

5. How to empower countries to move to local marketplaces?

Progress of European power market design was historically based on progress achieved by early movers. Market coupling was first implemented by France, Belgium and Netherlands and then gradually expanded to cover all of Europe.

Contrast this to the challenging progress on power market improvements in recent years. Integration of balancing markets across Europe started with the Balancing Guideline over ten years ago but is not expected to conclude before 2030. Delays are not a reflection of a lack of dedication, all parties involved have dedicated large human and financial resources to these processes. It is more likely that the large delays are caused either by the challenge to find solutions that work in the context of a market design that does not respect Kirchhoff's law, or by the challenge to find good solutions on questions that are highly technical but have large economic implications in a consensus-oriented process on a European scale.

Can local marketplaces be implemented at the scale of countries, or groups of countries, to facilitate rapid implementation? These pilots could then also serve as blueprint for a common application across Europe. This could build on North America experience. Following the PJM Interconnection (the ISO in the Pennsylvania – New Jersey – Maryland area) in 1998, seven further regional power markets moved to local market prices. This illustrates the viability of such pilot implementation.

Poland did attempt a transition to locational marginal pricing in 2016. Three options were considered:

1) a complete nodal pricing implementation
2) retaining day-ahead market zonal, freezing the outcomes, followed by nodal intraday-markets
3) only the real-time price for balancing would be nodal, while everything else remained zonal

To simplify the interactions with neighboring zonal approaches, Poland decided to pursue the third option. While it offers the least direct benefit as the limitations of the zonal approach would remain, it would make Poland ready for further future progress on implementing nodal pricing.

The scale of hurdles for the implementation subsequently increased with new requirements from the Balancing Guideline and framework, and additional restrictions on pricing. While 'off-the-shelf' solutions for operational and commercial aspects of locational marginal pricing are available from three established vendors, it was challenging for the vendor to adapt to the variety and changing additional requirements imposed by EU network codes and methodologies. Hence the Polish network operator stopped the contract in 2019 and reversed to a zonal perspective. Since then, Poland participates in the efforts to comply with all the requirements from EU network code and methodology.

The Polish experience shows, as learned from contributions to the debate from workshop participants, that, for a feasible development of a backbone pilot, the respective frontrunners must be granted derogations from a set of network codes and methodologies that would otherwise (i) enhance complexity and could (ii) ultimately undermine implementation efforts. There remains a positive perspective on nodal pricing and support of progress. However, PSE does not see how it could be implemented in Europe unless it is credible that the necessary derogations from the relevant European target model Guidelines and Network Codes are in place.

6. Is it possible to pilot local marketplaces at city level?

A more local approach towards piloting could be pursued at the scale of cities or rural regions. As the market design evolves to embrace renewables and flexibility, this will likely require that local market prices are shared with final users using distribution system networks or radio signals. This raises the question of how this could build on existing infrastructure like local data hubs (prescribed for smart meters by EU regulation), and local flexibility markets (implemented by DSOs often through contracting with a service provider).

Hence, there might be a large value of piloting local marketplaces. They would comprise a local clearing price that reflects the value of electricity and thus incentivizes demand to contribute both to energy balancing and grid needs. This could offer a variety of benefits:

- assessing business opportunities for retailers to support consumers in unlocking flexibility and reducing energy costs and risks
- exploring and establishing communication protocols between the national marketplace and local marketplaces, as well as between local marketplaces and consumers
- testing options on how to use local marketplaces to support DSO level congestion management
- gathering experience on how consumers respond to local market prices.[3]

How could a pilot for local marketplaces be operationalized?

- It could be based on the national wholesale price. Then, the use of flexibility has to be constrained, whenever it escalates rather than resolves congestion.
- It could be based on a shadow local market price derived from redispatch calculations at TSO level? Today, regional control centers, each covering several European countries (RCC), are calculating capacities (in core regions) for flow-based markets for DA and ID. They are in the process of building regional cooperation redispatch mechanisms that would combine costs and prices of assets across the region and could thus also provide shadow prices. However, the price is calculated day ahead, while the energy market continues subsequently. Hence, it is considered to possibly freeze market results for impacted participants.

[3] While in the past TSOs were concerned about too slow responses to price signals, increasing usage of batteries that can instantly respond is now starting to capture their attention. Exploring how to handle such situations could be valuable for TSOs partnering with such local marketplace pilots, including assessing how to (i) impose ramping constraints building on the common practice for DC interconnectors (ii) ensure in two or multiple settlement process early alignments.

7. How to protect market participants against local price risk?

Some argue that local market prices should be introduced to guide the location of investment choices. According to this narrative, in parts of a country with high renewable shares, the local market price for electricity will be so much reduced that large industrial investments can be attracted. While this narrative is not empirically substantiated, it has succeeded in triggering in other regions concerns for industrial development and resulted in large scale opposition to local market prices.

This opposition to the introduction of local market prices now jeopardizes the secure operation of power systems, investments in flexibility, and consequently renewables. Ironically, an unproven narrative can result in real negative effects for the power system and, ultimately, even for industrial prospects in the entire country.

It is important to recognize that for the power system, the location of investments is important. For this reason, a variety of mechanisms exist to guide the location of different types of investments. The objective and investment effect of local market prices must therefore be considered for the different types of investments in the context of these pre-existing mechanisms, as illustrated in Table 1.

	Households	Industry	Storage	Power to X Data center	RE	Conventional generation
Local market price			**X**	**X**		**X**
Grid tariffs and charges		**X**		**X**	**(x)**	
RE auction					**X**	
Regional Heat Planning	(X)	**X**			**X**	
Capacity mechanism						**(X)**

Table 1: Existing electricity market mechanisms and their objectives in conveying locational investment incentives to different market participants

For households and industrial consumers, local price differences are not expected to be big enough to redirect investments towards locations with potentially lower prices within a country. The uncertainty about local prices can, however, contribute to a perception of increased risks that result in delays or cancellation of investments. Wherever local prices have been introduced, this was accompanied by hedges for consumers against local price differences. Consumers are either exposed to the zonal average power price or granted permanent access to financial transmission rights to hedge local price differences.

However, households' investment decisions, such as heating system choices, can be guided by regional planning as an alternative mechanism. Where district heating systems exist, it may be inefficient to upgrade electricity distribution grids to supply decentralized heat-pumps. Hence, heat planning can guide the households' heating system investment decisions instead of local market prices.

For industrial consumers, the regional planning guidance will, in many instances, inform the type of activity that can be pursued at a location, and the available grid capacity. This may guide the location of electricity intensive industrial activities within a region (in combination with, in some instances, costly and lengthy upgrades). In North American nodal pricing markets, commercial and industrial customers are mostly exposed to a zonal average price. In some market regions (PJM, Ontario Independent Electricity System Operator, Midcontinent Independent System Operator (MISO)), large industrial consumers can opt into the nodal price. They already have the scale and sophistication to employ and benefit from price-driven load management strategies.

For investments in battery, heat and other types of storage capacity, the local price signal could be very informative and decisive for the business case. Currently most of these choices are guided by the structure of grid tariffs. Unfortunately, they are primarily motivating behind the meter solutions rather than system integrated approaches.

It is widely recognized that with increasing penetration of solar energy, it will be highly valuable to co-locate battery capacity to reduce local grid needs. For wind plants, variations of production are less periodic and the amount of energy that needs to be stored is larger. For electricity users, there is a strong economic case for storage of thermal energy and intermediary products. The location of such storage will be more beneficial in industrial sites or district heating systems regions with the corresponding local market price pattern.

This illustrates how local market prices can be beneficial for the business case of investments in flexibility and the overall energy system design and efficiency. The experience from energy sharing networks confirms that, with a suitable price signal, investments in flexibility also increase.

For investments in extremely large power consumers like data centers or producers of liquid fuels from hydrogen, it will be decisive to consider the power price profile in combination with other local factors (access to data hub, hydrogen infrastructure). Hence, exposure to costs and benefits of local market prices may, in contrast to the rest of industrial electricity use, be desirable.

For renewable power generation a variety of mechanisms exist to provide regional and local guidance. They can include exposure to deep grid connection charges, planning provisions and clearing provisions in tenders for long-term support with sliding market premium, or long-term hedges with contracts for difference. In principle, exposing renewable projects to local market prices could provide an additional local incentive, possibly even substituting for other mechanisms. In practice, however, the exposure to local market price risk will be difficult to hedge in the market for durations of 20-25 years. Hence, local market price risk could translate into significant revenue uncertainty and higher financing costs. For this reason, further refining existing mechanisms to guide locational choices of renewable investments should also be considered while hedging renewable projects against local market-price risks.

Finally, **investors into conventional generation** could receive locational guidance through the design of capacity mechanisms, for example in cases of reliability reserves. If conventional generation is exposed to local electricity prices, applying learnings from North American power markets, hedging instruments such as financial transmission rights could be issued and used that to hedge locational price risks for these investors. It is also important for this group of market participants how to deal with legacy contracts when transitioning to local marketplaces. Again, experience from North America shows that, while complex, it is possible to transform these contracts into a new market design.

These examples illustrate the variety of pre-existing regulations, and large differences across the different use cases that will need to be considered. This also provides opportunities to design suitable approaches to ensure that sensitive consumers and investors are hedged against local price risks.

8. Conclusion

Increasing redispatch costs and restrictions on the deployment and operation of flexibility, e.g. large-scale batteries struggling to obtain grid access and being limited to operate in balancing mechanisms, have led to a widely shared perception among workshop participants that changes in market design are inevitable. However, the resulting uncertainty about when such changes would materialize and how they would be pursued, e.g. whether they would involve zonal splits or a transition to local marketplaces, result in an atmosphere of regulatory uncertainty and investment instability. After discussing the theoretical and operational advantages that a shift to local marketplaces would entail, participants highlighted: the requirements that market design must be thought about from the consumer-perspective, that more practical knowledge could be gained from piloting by individual member states, and that local marketplaces must be accompanied by strong hedging mechanisms against locational price risks.

The workshop thus contributed to the creation of a vision of how local marketplaces could be implemented in Europe. Throughout the workshop, many insights were gained, but open questions remain, and many details are still subject to further discussion:

- For an efficient operation of the electricity market, a real-time market reflecting the locational value of electricity is fundamental.
- The discussion on locational marginal pricing in Europe has been going on for many years. For new momentum, it must be discussed bottom-up from the consumer-side.
- Local marketplaces offer benefits beyond the efficient operation of markets. In an environment of geopolitical tensions, the aspect of system and cyber security should be more strongly explored.
- While the European target model of zonal pricing is strongly enforced, the target model in US ISOs is seen as guidance and thus allowed for more flexibility and innovation. It should be evaluated how regulatory sandboxes could be implemented for front-runner countries to implement local marketplaces.
- The transition period, especially the transformation of legacy contracts, needs to be carefully planned.
- While the current goal is to unlock flexibility, the long-term implications of large-scale flexibility that can instantaneously be switched on and off must be considered already now. There is a need for rules on scheduling, such that flexibility helps to tame volatility instead of amplifying it.