Energy Education Series: Nodal vs Zonal Market Design

Our Energy Education Series aims to provide readers with longer form analysis of industry trends and market dynamics.

Max Gotilott (Lead Author)
Alexey Cherniack (Editor)

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A Background on Energy Market Settlement

Wholesale electricity market design generally follows two approaches: zonal and nodal energy market pricing. Zonal pricing sets a single price for a larger geographic area, while nodal pricing determines prices at individual transmission substations. This difference has significant implications for both efficiency and market behavior.

Nodal electricity pricing, determined at the transmission substation level, offers precise economic signals to market participants, facilitating informed operational decisions considering losses and grid congestion at the point of generation. It also incentivizes strategic location choices for producers, consumers, and storage operators. Nodal price models derive generator prices at thousands of different price points on the system, however the prices that customers typically pay are weighted averages across sub-regions such as within state or utility boundaries. Nodal pricing is adopted throughout most of the U.S., as well as in Argentina, Chile, Mexico, New Zealand, Peru, Russia, and Singapore.

Conversely, zonal pricing, prevalent in EU countries, clears wholesale markets assuming a constraint-free power system within each bidding zone. This results in uniform hourly day-ahead power prices across all users within a zone, with most zones aligning with national territories[1] and where market clearing considers only transmission capacity constraints between different zones. Most EU countries clear at a single zonal price for example. Transmission lines within a zone are presumed to have infinite capacity, although this assumption is increasingly disputed. However, this approach can lead to infeasible power flows within zones, managed by Transmission System Operators (TSOs) through redispatch measures.

Major Issues with Zonal Pricing

Originally expected to be infrequent, these interventions have escalated due to rapid generation capacity growth outpacing transmission capacity, particularly in remote areas. Redispatch has also been exacerbated by large numbers of renewable energy projects that have often clustered in export constrained regions. Consequently, there's been a surge in volatile flows and associated redispatch costs (ACER and CEER, 2021a). Infeasible power flows[2] dedicated by least cost dispatch modeling inevitably require administrative redispatch, which helps avoid grid overload but has limitations:

- Increased Costs: Redispatch can be expensive, as generators typically need to be compensated for adjusting their output (both up and down) or consumers for adjusting their consumption.
- Market Disruption: Redispatch disrupts the original market clearing results and can introduce uncertainty for market participants.

[1] In the EU, most bidding zones are equivalent to national territories -as of 2021, exceptions are Sweden (4 bidding zones), Denmark (2 bidding zones) and Italy (7 bidding zones). Norway (5 bidding zones) is outside of the EU but part of the internal electricity market. Conversely, Germany shares a bidding zone with Luxembourg, as well as the Republic of Ireland and Northern Ireland

[2] An example has been drawn in Appendix A.

- Gaming the System: In some cases, redispatch might incentivize strategic behavior by market participants to manipulate prices and benefit from the adjustments. At times of significant intra-zonal congestion, zonal balancing energy prices and the imbalance price can provide perverse incentives to grid users in real-time, which can endanger system security (Chaves-Ávila et al., 2014).

Nodal Pricing Has Some Clear Advantages

Estimates suggest that the direct benefits of nodal pricing can range from 1-4% of operational costs, translating to billions of Euros saved annually in the EU. Similar success stories exist in the US, where markets transitioning from zonal to nodal pricing saw savings exceeding implementation costs within a year (Neuhoff and Boyd, 2011).

A recent MIT study (A. Eicke & al., 2022) addressed key concerns regarding the implementation of nodal markets in Europe, with the first concern being imbalance and the "inc-dec game." In this game, generators situated behind network constraints inflate their bids, confident they'll still be dispatched, while those ahead of constraints lower bids to secure compensation for downward redispatch. Research on the Italian power market by Graf et al. (2020) demonstrated that such strategic behavior significantly inflates generation costs. The potential for gaming is more pronounced in zonal markets, particularly in Italy, structured into seven bidding zones unlike most EU countries. Alaywan et al. (2004) noted increased costs due to inc-dec gaming as a primary motivator for transitioning from zonal to nodal markets in CAISO.

Under nodal pricing, inc-dec gaming becomes untenable due to consistent alignment between trading areas and the transmission network's physics. However, market dynamics change with power flow distribution, particularly when network constraints arise. This can however lead to heightened market concentration in specific nodes or clusters, where a handful of generators wield significant influence over generation capacity, but only if they are situated in load pockets. Such concentration offers a prime opportunity for price-setting. Consequently, the exercise of market power in nodal markets directly impacts wholesale electricity prices in both day-ahead and real-time markets. Recognizing this risk, U.S. nodal markets have implemented market power mitigation mechanisms. These mechanisms entail automatic evaluations of potential market power issues before market clearing, potentially curbing bids from strategically located generators with market power potential. This assessment can result in constraining bids of generators that are deemed to be strategically located and have the potential to exercise market power.

Another concern is volatility – nodal markets are more volatile by design. Nodal pricing reflets local grid conditions and when constraints present, this can lead to short-term price volatility compared to zonal pricing, increasing risk for participants like generators and retailers. The underlying concept is that price volatility is intended to provide generators with short term price signals to increase or decrease production. Concerns exist about limited counterparties for hedging at individual nodes, but this can be mitigated by utilizing trading hubs that combine prices from multiple nodes – which is standard throughout US markets. However, despite a robust forward hedging market in the U.S., companies might still face "basis risk," the price difference between a contract and their specific location. Financial instruments like Financial Transmission Rights (FTRs) and locational forward products can help manage this basis risk, but limitations like short FTR contract durations, difficulty in precisely estimating FTR quantity needs, and potential subsidy concerns associated with FTRs highlight the need for ongoing considerations to ensure effective risk management in nodal markets. Also this issue is not specific to nodal markets as discussed in Batlle et al. (2014), but rather exacerbated in them due to the more important role of FTRs.

Balancing the Risks of a Nodal Market

Nodal pricing, with its location-based electricity costs, affects both consumers and generators. While household bills might see minimal impact due to wholesale prices being a smaller portion of their total cost, industries are likely to experience a more significant change. To mitigate these effects, strategies like consumer node grouping, sharing congestion revenue with end users, and targeted policies to address energy poverty and industrial needs can be employed. Much of this has been implemented in the US market already, however it is always a work in progress and the challenges of renewable energy growth concurrent with transmission constraints will compound. Conversely, zonal markets, while implicitly subsidizing renewables, invariably lead to higher costs, which will also compound as renewables deploy in greater numbers. Policymakers considering adoption of nodal pricing may deem necessary additional subsidies of renewable generation, however distorting the wholesale electric market is an unwise approach to doing so, if possible. In any event, out-of-market subsidies are likely outweighed by the significant cost savings associated with reduced redispatch needs in nodal markets.

Appendix A: Example of Zonal Price Formation Issues

Let's take an example of Infeasible Power Flows in Zonal Pricing with Redispatch. Imagine a simplified electricity market with two bidding zones: Zone A (North) and Zone B (South).

Day-Ahead Market (DA)

- In the day-ahead market, generators and consumers submit bids for electricity at a specific price. Based on these bids, the market clearing process determines the zonal prices for both Zone A and Zone B.

Actual Day or Real-Time (RT):

- **Early Morning (around 4:00 AM): Grid Operator assesses the available transmission capacity** between Zone A and Zone B for the day based on grid topology and maintenance schedules.
- **Continual: Real-time monitoring** of power flows across the grid, including the flow between Zone A and Zone B, by Grid Operator.

Throughout the Day:

- **If necessary:** Based on real-time monitoring data, the Grid Operator can initiate **pre-emptive redispatch** throughout the day to address potential future congestion issues identified before they become critical.
- **Late Afternoon (around 16:00): Identification of infeasible flow:**. Let's say, Zone A has high demand (high zonal price). Zone B has a surplus of generation (low zonal price). Expected Flow: Ideally, electricity would flow from Zone B (surplus) to Zone A (high demand) to meet the needs. Grid Operator identifies that the actual flow between Zone A and Zone B is exceeding the available transmission capacity, creating an infeasible power flow situation.

- Redispatch[3]: To address this, the Grid Operator might employ redispatch. This involves instructing consumers (typically in Zone A) to reduce their consumption (demand response program) or more likely, producers in that zone to increase their generation to maintain grid stability.
- Challenges: While redispatch helps avoid grid overload, it has limitations:
  - Increased Costs: Redispatch can be expensive, as generators are typically compensated for adjusting their output or consumers for adjusting their consumption. Take for example a 2-settlement market in which a resource is economically dispatched in the day-ahead market and then not needed in the real-time market–it may still collect a higher payment in the day-ahead while settling up again a lower cost in the real-time market.
  - Market Disruption: Redispatch disrupts the original market clearing results and can introduce uncertainty for market participants.
  - Gaming the System: In some cases, redispatch might incentivize strategic behavior by market participants to manipulate prices and benefit from the adjustments. At times of significant intra-zonal congestion, zonal balancing energy prices and the imbalance price can provide perverse incentives to grid users in real-time, which can endanger system security (Chaves-Ávila et al., 2014).

Appendix B : The inc-dec game

The balancing market is primarily used to address **short-term** imbalances between supply and demand within specific zones. It achieves this by:

- **Activating available reserve capacity:** This includes **both** Reserve primaire (RP) and Reserve Complementaire (RC) procured through separate markets in France.
- **Adjusting generation output** from participating power plants.
- **Implementing demand response programs** to encourage reduced consumption during peak periods.

The Grid Operator continuously monitors the grid and initiates adjustments in the balancing market when real-time imbalances are detected. The imbalance price reflects the cost of these adjustments. Consumers (both industrial and household) ultimately bear the cost of real-time adjustments made through the balancing market, including the activation of reserve capacity, either directly based on their deviations from scheduled consumption or through fixed tariffs that might be adjusted periodically to reflect changes in overall grid balancing costs.

Suppose we have the same zonal electricity market as outlined before with two zones:

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[3]**Dispatch:** Refers to the standard process of scheduling and directing power plants to generate electricity based on the market needs.It involves using the submitted bids from generators and consumers to determine the most cost-effective way to meet the overall electricity demand.

Redispatch: Deals with situations where the initial market schedule needs to be adjusted after it's been established. There may be various reasons for redispatch. **Local network issues:** Unexpected congestion on local power lines might require adjustments to generation output to avoid overloading the network.**System-wide reasons:** High levels of non-synchronous generation sources (like wind or solar) might require curtailment (reduction in output) to maintain grid stability. Redispatch aims to prevent or mitigate situations that might lead to frequency deviations by addressing power imbalances.Redispatch can actually occur **before or alongside** deployment of Frequency Control Reserves, depending on the specific situation. Power plants instructed to adjust their output through redispatch are typically compensated using a market-based approach in which plants may submit bids for adjusting generation in response to redispatch instructions. They're compensated based on the market clearing price for their adjustments.

- Zone A has a high demand for electricity due to extreme weather conditions & Zone B has surplus generation capacity.
- The imbalance price in Zone A is $75/MWh higher than the zonal balancing energy price ($300/MWh).
- The imbalance price in Zone B is $50/MWh lower than the zonal balancing energy price ($150/MWh).
- Zonal balancing price in zone A is assumed at $225/MWh.
- Zonal balancing price in zone B is assumed at $200/MWh.

Now, let's consider two types of market participants: generators and consumers.

Generator Strategy:

- Generator in Zone B: This generator has surplus capacity and can produce electricity at a cost of $50/MWh. However, due to the surplus capacity in Zone B, the zonal balancing energy price might be lower than the generator's production cost.
- However, the generator sees that the imbalance price in Zone A is significantly higher than the zonal balancing energy price. So, the generator decides to strategically export electricity to Zone A during periods of congestion.
- During congestion in Zone A, the generator exports electricity to Zone A at the zonal balancing energy price, let's say $225/MWh.
- Meanwhile, it buys electricity from Zone A at the zonal balancing energy price to balance its own production and consumption in Zone B.
- The generator profits from the price difference between the zonal balancing energy price in Zone B and the imbalance price in Zone A, which is $300/MWh - $200/MWh = $100/MWh.
- If the generator exports 1000 MWh of electricity during congestion, its profit would be $100/MWh * 1000 MWh = $100,000.

Consumer Strategy:

- Consumer in Zone A: During congestion, the consumer faces high zonal balancing energy prices. Let's say the zonal balancing energy price in Zone A during congestion is $225/MWh (illustrative value).
- To mitigate costs and potentially earn revenue, the consumer decides to reduce consumption during congestion periods instead of increasing it.
- By reducing consumption, the consumer helps alleviate the imbalance in Zone A and may receive compensation at the higher imbalance price if they are able to reduce their consumption as per the Grid Operator's instructions.
- Let's say the system operator offers compensation at the imbalance price of $300/MWh for each MWh of reduced consumption.
- If the consumer reduces consumption by 500 MWh during congestion and receives compensation at $300/MWh, their profit would be $300/MWh-$225/MWh * 500 MWh = $37,500

The consumer's overall strategy combines:

- A **day-ahead market bid** that is slightly lower than their true expected consumption, anticipating potential congestion and the need to reduce demand.
- **Real-time adjustments:** During congestion periods, the consumer actively reduces their electricity consumption as instructed by the system operator (if applicable) or based on their own cost-saving motivations.
- **Potential compensation:** By successfully reducing consumption, the consumer aims to benefit from compensation offered by the system operator at the imbalance price, further offsetting their potential costs.

Appendix 3: Summary Nodal Market Issues and Solutions (A. Eicke & al., 2022)

Table 3: Summary of the arguments against nodal pricing and possible mitigation options

	Argument against nodal pricing	**Main finding and possible mitigation options**
1	Market power	Market power may arise in zonal redispatch markets and in nodal wholesale markets. The wholesale market is easier to monitor, and ex-ante market power mitigation tools have been successfully implemented in nodal markets.
2	Barriers for flexibility a. No continuous ID trading b. Demand and storage participation c. Topology changes	a. Continuous ID trading is possible under zonal and nodal pricing, but requires trade limitations or subsequent redispatch. Intraday auctions are the preferred option. b. Demand and storage can participate in a central dispatch model. Self-scheduling is possible and bidding formats evolve. More volatile prices improve their business case. c. The value of topology changes is lower, and embedding the grid topology in the market clearing is not excluded by design.
3	Market liquidity	More price volatility will create liquidity in forward markets. Long-term hedging can be done in hubs. Locational risk is not excluded, but can be to a large extent mitigated with FTRs or basis swaps.
4	Investment risk	Locational risk that is socialized under zonal pricing is borne by market parties under nodal pricing. This improves incentives for siting decisions, but hedging the locational risk is hard.
5	Complexity	The spatial granularity of prices is one driver of computational complexity next to the pricing rule and bidding formats.
6	Locational price differentiation a. For consumers b. For renewable generators	a. The impact on average energy prices is limited in most cases because the wholesale power prices make up only one third of household consumers' electricity bills. The impact for industry is larger. Mitigation tools include the grouping of nodes for consumers, the allocation of congestion rents to end users, and targeted energy poverty and industrial policy-related measures. b. Zonal markets provide implicit subsidies to renewables. Explicit financial support to renewables might increase, but its costs would be more than offset by lower redispatch costs.

(A. Eicke & al., 2022)
https://energy.mit.edu/wp-content/uploads/2022/02/MITEI-WP-2022-01.pdf