Can a Joint Energy and Transmission Right Auction deliver well-functioning long-term cross-border electricity market in Europe? – Comparison of long-term market performances under nodal and zonal pricing

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Introduction

1.1 Long-term electricity market for renewable integration

An organized forward market or bilateral long-term contracts can be seen as important parts of the electricity market and complement to the competitive spot market. The positive effect of long-term contracts for renewable integration can be multi-folds. For renewable generation plants, the high fixed investment costs and CAPEX dominant characteristics do not always encourage investment under the unstable spot market price. Hedged against the volatility from spot market, long-term contract enables the investors to invest in high fixed cost technology. The prospect of certain future cash flows in a long-term contract can help solve the counterparty credibility problem and facilitate bank financing [1].

In this research, long term refers to a period of at least one year or several years ahead of the electricity delivery. In the climate policy context, one salient characteristic of bilateral long-term contracts is that they allow the buyers to express preferences in terms of technology choice. This is seen as the driver for emergence of renewable power purchase agreement (PPA) contracts for large industrial consumers that prefers to have the green electricity label. At the same time, energy intensive consumers or some retailers are also potential beneficiaries of cross-border renewable PPA as they look for low-cost green electricity at stable price. Long-term contracts shield the market participants from too high or too low prices in the sport market.

Currently, the long-term power purchase agreements are on the rise within national boundaries in Europe [2]. There are mainly two types of PPA contracts: sleeves PPA and financial PPA. Under the sleeves PPA, two contracting parties can sign a long-term contract with a fixed quantity at fixed price, while involving the balancing responsible party with a management fee. The balancing responsible party is responsible to manage the deviation from the contracted quantity. Grid fees are paid to the TSO for the use of the network. Under the form of financial PPA, two contracting parties can sign purchase agreement with a fixed price without physically delivering electricity. The renewable producer sells the electricity in the wholesale market, while the buyer purchases the contract specified amount from other players in wholesale market. The long-term contract fixation price is compared with the wholesale market price. For instance, when the wholesale market price is lower than the contracted price, the buyer needs to pay the difference to the seller. The wholesale market price is the price formed within the bidding zone of the contracting parties.

1.2 Benefits of cross-border long-term market

As the decarbonization is accelerated by the FIT for 55 package, EU legislation is expected to translate the new greenhouse gas reduction target into actionable plans, including raising the renewable electricity target for the next decade. Top-down set renewable target and growing demand for renewable electricity from consumer side both call for large scale of new generation investments in the most cost-efficient locations. Natural resources for developing renewable energy are not evenly distributed among Member States, therefore the development of long-term market across borders is instrumental for a cost-efficient energy transition in Europe. Furthermore, the lessons learned from California crisis show that the lack of long-term contracts increases the risk of market power within a bidding zone [3]. In other words, long-term contracts across borders can potentially benefit the consumers in the national electricity market with new entries and thus potentially yield an anti-trust effect.

A well-tailored long-term contract needs to be able to allocate the risks to parties who can best manage it and charges risk premium accordingly. The long-term transmission rights that give involved players the options to hedge congestion risk are essential to complement the cross-border long-term contracts. Long-term contracts are not uniform in terms of risks depending on the contracting parties' positions in market and preferences. Therefore, different players may want to choose different risk hedging instruments for their cross-border trade. Not only is the interest very high to hedge the cross-border congestion risk financially or physically, but also there are buyers that wish to procure energy that implicitly contains the transmission access in the long-term time frame. It is important to include a variety of options and make them compatible in the long-term market design.

1.3 History account and status quo in Europe: from long-term priority access for interconnections to the long-term transmission right challenges

When liberalization started, a large portion of the interconnection capacity had been granted to the former vertically integrated utilities in the form of long-term priority access. De Hauteclocque discusses the EU perspective of long-term priority access of interconnection capacity for the electricity liberalization [4]. The Third Package has focused on mandating Third Party Access to provide level playing field to all market entrants. The prioritized long - term transmission access to interconnection capacity granted prior to the liberalization is viewed from competition perspective to be monopolization of essential facility and anti-competitive by European institutions. The antitrust law, in particular, examines the prioritized long-term transmission access granting methods, in order to determine whether the methodology applied gives an unfair advantage to dominant players in certain markets. The access granting from system operator to its affiliated arm within vertically integrated utilities raises concern over abuse of the dominant position.

Therefore, the European solution has been a standard textbook market reform to develop a short-term market and coordinate transmission and generation in this time frame [5]. In particular, firstly explicit and then implicit auction has been used as interconnection congestion management method for a day-ahead market. As market participants need to anticipate and match the bidding of transmission rights with their cross-border energy trade in explicit auctions, the implicit auctioning becomes the preferred method [4].

Commission Regulation 2016/1719 requires TSOs to develop harmonized rules for allocating physical transmission rights and financial transmission rights [6]. The regulation sets out rules to the development and cost allocation of long-term transmission rights. The allocation of cross-zonal capacity at long-term time frame can be organized through explicit auction. In the Joint Auctioning Platform set up by the TSOs, currently available long-term transmission rights for interconnections only cover one-year[1].

Will the implementation of joint explicit auction of interconnection capacity in long-term time frame bring an efficient cross-border long-term market? From the cost and risk allocation perspective, Beato points out there exist different incentives of TSOs and transmission users for the development of long-term transmission right products [7]. Unless the TSOs are guaranteed cost recovery from their regulators, they would be reluctant to increase the quantity and duration of long-term transmission rights. TSOs are required to ensure the firmness of the long-term transmission rights, or otherwise they need to compensate the right holders and face the risk this cost is not approved to be reimbursed in the network tariff.

1.4 Can the explicit auctioning on interconnection capacity or a joint energy and transmission right auction across borders in the long-term time frame deliver the economic gains for Europe?

As a consequence of incomplete information, it is difficult for the market participants to form a portfolio of physical transmission rights for bilateral contract under zonal pricing. There will be some bilateral contracts made infeasible by the system operator. History in PJM also supported the analysis outcome where a lot of bilateral contracts collapsed under zonal market and facilitated the transition from zonal to nodal pricing [8]. Another implication is in the long-term time frame, the common grid model needs to be calculated in a conservative way to take account of higher uncertainties and the nature of zonal model. Consequently, much less cross-border long-term trade would be allowed if all the bilateral contract needs to be feasible, which leads to lower network utilization in this time frame.

The underlying market structure of explicit auctioning of physical transmission rights is decentralised with the market participants obtaining the physical transmission capacities given by the network owners. In this research, we make the attempt to move one step forward by implementing a joint of energy and transmission right auctioning in the long-term time frame in conjunction with day-ahead market across-borders with a stylized network. The objective of the study is to assess that with energy and transmission use simultaneously optimized in the long-term market, will the zonal market design in Europe deliver the same level of economic gains in comparison with that of the nodal pricing? Are the current market design and settlement rules in Europe compatible to embrace the cross-border long-term market development?

2 Joint transmission right and energy auction model

2.1 Model description

This research uses a central auction model proposed by O'Neil on the case studies to compare system wide economic efficiencies of auctioning transmission rights and energy under nodal pricing and zonal pricing [9]. The joint transmission right and energy auctioning model is selected to compare its implementation values as several features of the model are desired:

i. It includes both the financial transmission rights and the physical transmission rights in the same model. The physical transmission right is also called flow gate right in some

[1] https://www.jao.eu/

literatures. Among the two rights, the calculation of financial transmission rights requires a central view of the network conditions from the system operator. The physical transmission rights can be acquired without central auction as the physical limits of certain transmission elements can be determined separately by the owners of network assets [10]. This joint model presents a way to include the two types of transmission rights in the centralised auction process.

ii. The development of congestion hedging tools enables bilateral contracts at scale across borders by giving the contract parties the means to choose instruments to hedge congestion risks in different market time frames. It also supports the user flexibility by choosing financial transmission rights or physical transmission rights and allowing them to adjust positions in different time frames.

iii. The energy sale or purchase are brought in the forward market with transmission access prior to day-ahead market.

The auction model maximizes the value of accepted bids, including flow gate rights, point to point financial transmission rights and energy sale purchase contract. The market players can reconfigure the rights and trade them in secondary market. Inequality constraint includes the load flow constraint and energy supply demand balance. The bids need to include price as well as lower and upper constraints for energy sale/ purchase and transmission rights. In this study, only DC load flow constraints are included. There is no change of network typology in different time frames. In the nodal system, after each round of the forward market auctioning, the energy and transmission rights granted in the previous round are liquidated. It means all the financial positions held by the right holders are being bought back or sold back. The bid winners get their revenues according to the accepted volumes determined in the previous auction and prices determined by bids in the current auction. To sum up, the wide range of product and services that cover generation and transmission, the flexibility it gives to market players to choose different services as well as consistent market settlement rules across time frames makes the joint auction appealing in the development of a long-term electricity market.

The mathematical formulation of the auction model can be summarized by the formula:

$$Max\ \boldsymbol{b_1 t_1} + \boldsymbol{b_2 t_2} + \boldsymbol{b_3 t_3} + \boldsymbol{b_g g} \tag{1}$$

$$\boldsymbol{\beta_1 t_1} + \boldsymbol{\beta_2 t_2} + \boldsymbol{\beta_3 t_3} + \boldsymbol{\beta_g g} \le \boldsymbol{F} \qquad (\boldsymbol{\mu}) \tag{2}$$

$$\boldsymbol{\alpha_2 t_2} + \boldsymbol{\mu g} = 0 \qquad (\lambda) \tag{3}$$

Where:

$\boldsymbol{t_1}$ is a vector of the flow gate rights awarded to bidders. t_{1i} represents the ith bid by bidders to obtain rights and collect revenues from one or a portfolio of transmission element constraints. The term flow gate rights and physical transmission rights are interchangeably used in this research to refer to the rights for physical capacity on certain transmission element. Bidders can specify the highest and lowest amount with T_{1Lj} and T_{1Uj} respectively.

$\boldsymbol{t_2}$ represents the point-to-point financial transmission rights awarded to bidders. t_{2j} represents the jth bid for the right to collect nodal price differences between the designated node pairs. Bidder can specify the lowest and highest amount of the transmission rights they want to obtain with T_{2Lj} and T_{2Uj} respectively.

$\boldsymbol{t_3}$ is a vector of point-to-point financial transmission options. t_{3k} represents the kth bid for the option to collect nodal price difference between specified nodes. Bidder can specify the lowest and highest amount of the transmission rights they want to obtain with T_{3LK} and T_{3UK} respectively.

$\boldsymbol{g}$ is a vector of energy sale or purchase bids awarded to bidders. Lower and upper value of the bidder are given in the bid and represented by G_L and G_U.

$\boldsymbol{\beta_1}, \boldsymbol{\beta_2}, \boldsymbol{\beta_g}$ is a vector of the transmission rights needed on each transmission element per unit of each bid type. $\beta_{1ih}t_{1i}$ is the transmission capacity needed on transmission element h with per unit value of ith bid for flow gate rights. $\beta_{2jh}t_{2j}$ is the transmission flow induced by per unit of financial transmission right bid t_{2j} on the transmission element h. $\beta_g g$ represents the flow created on the transmission element by the energy purchase and sale bids.

F is a vector of the capacity limits of transmission network.

$\boldsymbol{\mu}$ is a vector of dual variables of the constraints. For each transmission constraint, there is a dual.

$\boldsymbol{\lambda}$ is the marginal cost of meeting demand at hub node defined for the power transfer distribution factor calculation.

As O'Neil et al analysed, point to point financial transmission option will be very unattractive under certain circumstance to the market players with the defined settlement rules. Therefore, this type of rights is not included in the case study of the research.

2.2 Spatial and temporal dimensions of the nodal and zonal market

The multi time frame joint transmission and energy auctioning model includes several types of products in a joint centralised auctioning: financial transmission rights, physical transmission rights and energy products in forward market and real time market. There is an integrated network and market operation by the system operator in the joint auctioning of energy and transmission right under nodal system. As O'Neil pointed out, Independent System Operator (ISO) responsible for market and network operation is at an advantageous position to host a joint energy and transmission right auction in forward market to include network constraint, generation, load, net import or export [11].

Locational marginal pricing is defined as the marginal system cost for delivering an incremental unit power to the specified node. Congestion revenue is the difference between the total payment from the buyers and the total receipt of the sellers, with both payment and receipt based on their respective LMPs. The financial transmission rights are settled based on the LMP differences between the node of withdrawal and the node of injection, thus from the user perspective holding the financial transmission rights would be sufficient to pay congestion charges based on nodal difference, regardless of how the power flows through the network. The physical transmission rights are paid based on the shadow price of the specified transmission paths, so it requires the user to calculate accurately the usage of transmission paths of the desired transaction. The supply side of the FTR auction is determined by auction revenue rights (ARR). The ARR holder can opt to receive the financial transmission right auction revenue or convert the ARR into FTR. In this study, the user holding ARR are all assumed to participate in FTR auction and receive the revenue from system operator. Since all the network capacity constraints are included in the optimization of different auctioning timeframes, there is no need for redispatch under nodal pricing.

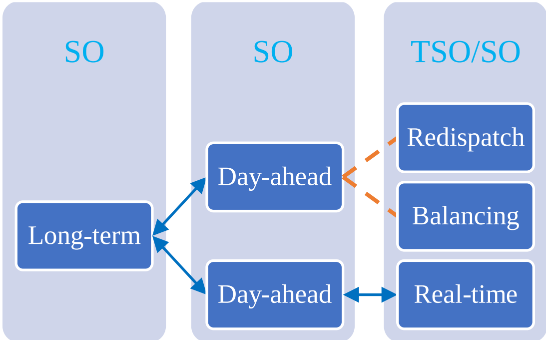


Figure 1 Market time frames and responsible institutions under different pricing schemes

In Figure 1, arrowed lines represent the auctions linked by the multi-settlement rules of the joint energy and transmission right auction. The auction winners from the previous auction pay for the rights in the time frame when the rights are allocated and receive the price determined in the current auction. For instance, for a bidder who wins a 100 MWh of FTR between the specified locations in the long-term auction with a price of 5 €/MWh, the FTR bid winner pays to the SO the price determined in the long-term auction 5€/MWh multiplied by the allocated quantity by the SO: 100 MW. In the long-term, this bidder pays the SO 500€ to obtain the rights. If the day-ahead price difference between the specified locations turns to be 10€/MWh, the bid winner will be paid by 1000 € for the 100 MWh of FTR.

The upper part of the figure shows that the multi-settlement rules link the long-term and day-ahead auction under zonal pricing. The system operator in these two periods can either be power exchange or the TSO in the decentralised governance structure. After the gate closure of spot market, day-ahead market in the case study of this research, the redispatch and balancing are the sole responsibility of the TSOs who manage the grid and act as single buyer in the market place. So naturally TSOs are at the better position to make settlement. The term system operator in this time frame refers to the TSOs only. The lower part of the route depicts the markets linked by multi-settlement rules in the case study: long-term, day-ahead and real-time. The bid winner who holds rights from the market in the left side of the arrowed line will be rewarded in the market time frame at the right side of the arrowed line. The term system operator refers to an independent system operator that acts as market operator and network operator.

In the proposed implementation under nodal pricing, the auctions of transmission rights and energy before real time markets are financial, so the auctioning bids will not be linked with the physical dispatch and actual use of the transmission network. The market participants can participate in the bid, in order to hedge the price differences between nodes or congestion price over certain transmission link. The auctioning outcome is liquidated after each round. Only in real time market, the cleared bids are treated as physical commitments. Generation capability and bilateral contracts are taken as constraints for the real-time market under the JETRA model.

Therefore, the problem discussed in section, i.e prioritized long-term physical access to interconnections that may possibly exert anticompetitive effect by blocking the new entrants, does not apply with the auctions that provide financial hedging in nature. Temporal and spatial dimension of the JETRA under nodal pricing is summarized in Figure 2.

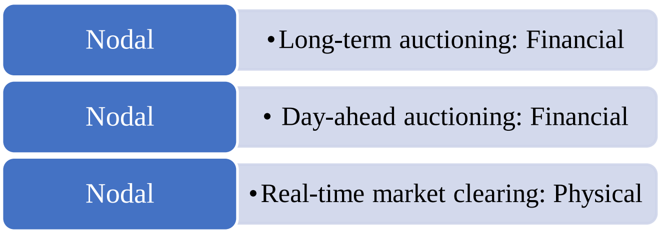


Figure 2: Temporal and spatial dimension of the JETRA under nodal pricing

Under the zonal pricing, the joint energy and transmission right auction in the long-term and day-ahead market can be organised by power exchange with grid input from system operator, followed by redispatch and balancing markets organised by system operator. In theory, the nodes with similar electrical characteristics and geographical proximity can be aggregated into the same zone. The intra-zonal congestion cost should be minimal compared to inter-zonal congestion [12]. The zonal market is compatible with a decentralised market structure, in which the power exchange and system operator at national level interact to clear the market. In the long-term and day-ahead time frame, the system operator calculates a simplified grid model with nodes aggregated into zones. The power exchange accepts bids from market players and clears the market incorporating the inter-zonal constraint from grid model. At the closure of the day-ahead market, the power exchanges need to submit the schedules resulting from market clearings to system operator.

Both long-term and day-ahead market follow the inter-zonal network constraint in optimization. The awarded bids of financial transmission rights, physical transmission rights and forward energy contracts are financial in the long-term market. That is to say, in the day-ahead market coupling, all the previously awarded rights and energy contracts are liquidated and the right holders are paid the quantity awarded in long-term auction with the zonal prices determined at the day-ahead market.

Sequential allocation of the physical network capacity is implemented since day-ahead market. In day-ahead market, implicit auctioning guaranteed the optimal use of both energy and transmission capacity. In the redispatch and balancing, system cost optimization is performed while taking into account transmission network constraint. The sequential allocation in these time frames means that unlike the joint auction under nodal pricing, the physical capacity that is allocated to market participants have physical commitment. In other words, they can not be liquidated by system operator without compensation.

A major difference in these markets is that the day-ahead market considers only inter-zonal constraints and the redispatch balancing market incorporates both inter-zonal and intra-zonal constraints in the case study. This sequential approach also has implication for the market size, a larger cross-border market is segmented into two small markets with less competition within the bidding zones. It is important to note that the energy and transmission rights settled at day-ahead market prices do not cover the cost after the day-ahead market gate closure. The temporal and spatial dimension of the JETRA under zonal pricing is summarized in Figure 3.

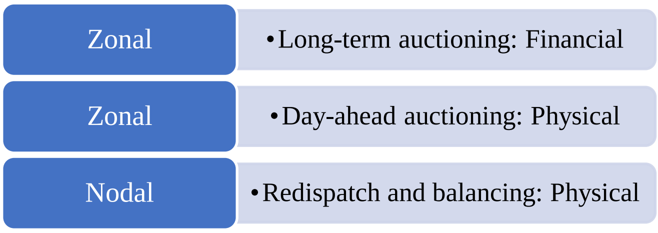


Figure 3: Temporal and spatial dimension of the JETRA under zonal pricing

2.3 Case study network and comparison indices

Using the network shown in Figure 4, a case study is constructed. The network capacity limit of line 1-2 is 200 MW and the capacity limit of line 4-3 is 250 MW. The other lines have a capacity limit of 400 MW. Given this network topology and the maximal demand in this case study being 525 MWh, the maximal flow on any transmission element will not exceed 328 (525 *0.625) MW. Lines with 400 MW capacity can be seen as transmission elements without capacity constraints. In the zonal network representation, node 1 forms zone west, while node 2, node 3 and node 4 form zone east. In the joint transmission and energy auctioning, suppose there are 5 bidders. As the bids are hourly based, the energy and transmission rights are represented in unit MW in the tables showing results.

- Bidder 1 bids for financial transmission right from node 1 to node 3 at 10 €/MWh with lower bound of 200 MWh and upper bound of 500MWh.
- Bidder 2 bids for energy sale from node 2 at 35 €/MWh with upper bound of 150 MWh.
- Bidder 3 bids for energy sale from node 4 at 20 €/MWh with upper bound of 300 MWh.
- Bidder 4 bids for physical transmission right for 100MW at 10 €/MW on the interconnection between node 1 and node 2 with upper bound of 150 MW.
- Bidder 5 bids for energy purchase from node 3 at 22 €/MWh with upper bound of 300 MWh.

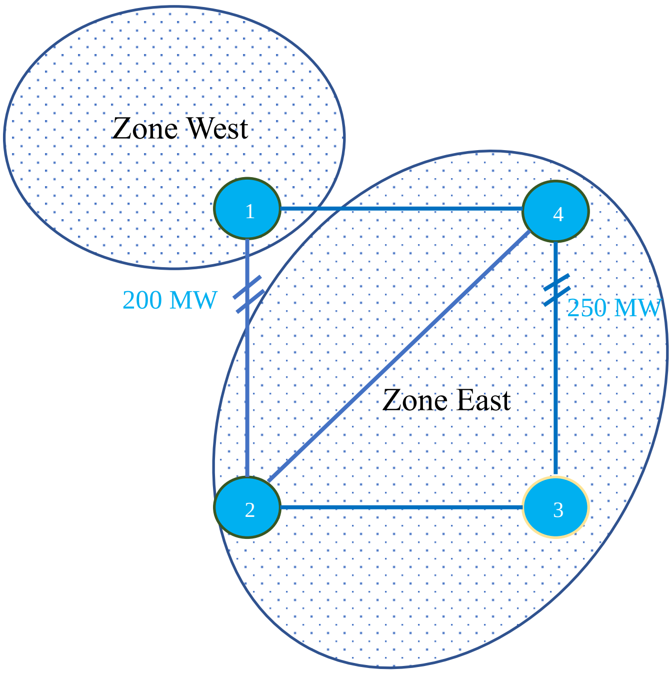


Figure 4 Four nodes network with two capacity constrained lines

Here we study three scenarios to compare the results in the nodal and zonal pricing market.

- In the first scenario, carbon price is low, so the marginal generator in the gas fired power plant at node 2 has a cost of 35€ /MWh. The real time load locates at node 3 and equals 500 MWh.
- In the second scenario, carbon price is high, so the marginal generator in the gas fired power plant at node 2 has a cost of 80€ /MWh. The real time load locates at node 3 and equals 500 MWh. Under the zonal model with the same amount 500 MWh cleared at the day-ahead market coupling with redispatch mechanism at play to alleviate network congestion, high carbon price will exert impact on redispatch costs.
- In the third scenario, carbon price is high, so the marginal generator in the gas fired power plant at node 2 has a cost of 80€ /MWh. The real time load locates at node 3 and equals 525 MWh. Under the nodal model, the deviation between the day-ahead auctioned volume and the real time load is dealt with in the real-time market clearing. In the zonal market, while there is 500 MWh cleared at the day-ahead market coupling in the zonal market, there is 25 MWh load deviation to be delivered by the balancing market. Therefore, both redispatch and balancing mechanism are at work after gate closure of the day-ahead market.

This case study assumes only the network users participate in the joint energy and transmission right auction in the market. There are no financial or virtual bids that are not backed up by physical generation or demand. In particular, the bidders who bid for financial transmission right and energy purchase contract are assumed to be agencies associated with demand at node 3.

Several indices are calculated to compare the outcomes in a nodal and a zonal market:

i. Firstly, revenue adequacy for the system operator is assessed. The ability to reach revenue adequacy or close to reach is desirable in cross-border cooperation. Revenue adequacy is defined as the capability of a system operator to pay the energy and transmission right holders from collected surplus from selling and buying energy and rights. The revenue adequacy for the system operator means the cost can be recovered from the market-based mechanism, therefore it can avoid administrative procedures to socialize the cost gap across different jurisdictional areas to pay for the bid winners.

ii. Secondly, total net payment for the user at demand node across different time frames is calculated in order to compare the dynamic efficiency of employing the congestion hedging instruments in the nodal and zonal market. It is important to note that in this research we assume the cost of transmission network usage is ultimately paid by the user that represent demand at node 3.

iii. Thirdly, the total payment for the ARR holding user is calculated to measure the economic efficiency of using the hedging instruments while taking into account different network utilization levels under nodal and zonal pricing for network investors. In the U.S market, the auction revenue of FTR can be given to the transmission network investors to remunerate their investment or to utilities as give back to ratepayers. In this study, we assume the user that represent the demand at node 3 is responsible to pay for construction and maintenance of the transmission network and therefore receives auction revenue right allocation from the SO. The reason to calculate the total payment net of the ARR revenue is that intra-zonal network use is not explicitly priced in the zonal pricing market process in this study, while all the transmission constraints are reflected with the nodal pricing. The net payment by user taking account the receipt from ARR rights in the FTR auction will give a better approximation of the total costs for users that will benefit from higher network utilization under nodal or zonal pricing.

3 Joint energy and transmission rights analysis under nodal pricing

In this section, a joint auctioning process of energy and transmission right is set in efficient manner to maximize the bidding values in each time frame. In the following scenario calculations, first the reference case is established under nodal pricing by showing the market process and we further investigate different scenario outcomes. Several topics are worth careful examination:

- How does the bid payments link markets in different time frames from user perspective?
- How is the settlement associated with auction clearing result?
- How does the higher marginal generation costs or bidding expectation such as a minimum energy and FTR procurement in day-ahead market change the LMP and thus the bidding payments?

In the cross-border market mechanism, low system cost across different time frames and the ability to send efficient short-term and long-term price signals market mechanism are both important considerations. Efficient market facilitates competition in a larger geographical area and lowers cost for users. Effective cross-border cooperation will require market mechanism to play its role, so less cost allocation negotiation and administrative process set in.

Table 1 presents the β values of each bid using node 3 as hub. In the nodal market, the β values of each bid correspond to the nodal PTDF values of the bid, with node 3 defined as hub node in this network. The β values and link capacities are given in positive and negative direction. For instance, the β values for bid 1 is shown in the fifth column in Table 1. Bid 1 represents financial transmission rights between node 1 and node 3. One unit of FTR means 1 MWh of injection at node 1 and withdrawal at node 3 that makes 0.5 MW of the power to flow through line 1-2 and then line 2-3. 0.5 MW of the power flows through line 1-4 and then line 4-3. The PTDF values on line1-2, line1-4 and line 2-3 are 0.5, while the negative directions of the same lines denoted as line 2-1, line 4-1 and line 3-2 have PTDF values of -0.5.

In the three scenarios under nodal pricing, regardless of the marginal generator cost the scenario selects or the set real time load value, the accepted bids in the case study are always bidder 1 and bidder 5 in the long-term auction. The auctioning results payment from the bid winners to SO in long-term auctioning are the same across the three scenarios.

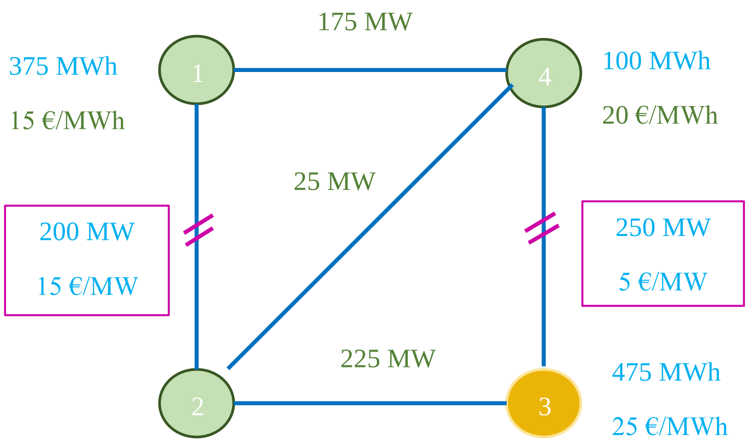
	Capacity (MW)	Bid 1	Bid 2	Bid 3	Bid 4	Bid 5	Shadow price (€/MW)
Line 1-2	200	0.5	-0.125	0.125	1	0	15
Line 2-1	200	-0.5	0.125	-0.125	-1	0	0
Line 1-4	400	0.5	0.125	-0.125	0	0	0
Line 4-1	400	-0.5	-0.125	0.125	0	0	0
Line 2-3	400	0.5	0.625	0.375	0	0	0
Line 3-2	400	-0.5	-0.625	-0.375	0	0	0
Line 2-4	400	0	0.25	-0.25	0	0	0
Line 4-2	400	0	-0.25	0.25	0	0	0
Line 3-4	250	-0.5	-0.375	-0.625	0	0	0
Line 4-3	250	0.5	0.375	0.625	0	0	5

Table 1 β values of each bid in nodal pricing on each network element

The last column in Table 1 displays the shadow prices of congested links as the dual variables of flow constraint. The interdependence between shadow prices of and the FTR is discussed by Oren [10]. The FTR price can be derived from equation 4. LMP difference between two nodes can be calculated using shadow prices of the transmission network path linking the two nodes and the nodal PTDF of these links. In the case study, node i is always the hub node, so its PTDF value on any transmission link is 0. The duality of energy balance gives the hub nodal price. The locational marginal pricing of other nodes can be derived based on the hub energy price.

$$LMP_m - LMP_l = \sum_{all\ flowgates\ h} SP_h * \left(PTDF_{h,m} - PTDF_{h,l}\right) \quad (4)$$

Where:
m denotes the withdrawal node.
l denotes the injection node.
h denotes the transmission element h on the transmission path that connects node m and node l.
LMP refers to locational marginal price of certain node.
SP refers to shadow price of certain transmission element.



denotes the injection nodes in the system

denotes the withdrawal nodes in the system

denotes the congested lines in the system

denotes the values directly obtained in the optimization

denotes the values indirectly derived from the optimization

Figure 5 Long-term auctioning results under nodal pricing

In the long-term auction, bidder 1 is awarded 375 MWh of financial transmission rights from node 1 to node 3. Bidder 2 and bidder 4 do not get their bids accepted. Bidder 3 is awarded 100 MWh of energy sale and bidder 5 is awarded 100 MWh energy purchase. The flow on the line 1-2 is 200 MW (0.5*375 + 0.125*100) and on line 4-3 is 250 MW (0.5*375 + 0.625*100). The flow on line 1-4 is 175 (375*0.5 + 100*(-0.125)) MW, line 4-2 being 25 (100*0.25) MW and line 2-3 being 225 (375*0.5 + 100*0.375) MW. Shadow price of link 1-2 and link 4-3 is 15€/MW and 5€/MW respectively. From shadow prices obtained in optimization we can also see that line 1-2 and line 4-3 reach the capacity limit. The locational marginal price in hub node 3 is the dual of energy balance equation that equals 25 €/MWh.

Using LMP and shadow price calculation formula, the FTR price for bid 1 that accounts for nodal price difference between node 1 and node 3 is 10 (15*0.5 + 5*0.5) €/MWh. Nodal price difference between node 4 and node 3 is 5 (15*0.125 + 5*0.625) €/MWh. The LMP at node 4 for bid 3 is 20 (25-(15*0.125 + 5*0.625)) €/MWh. Similarly, nodal price difference between node 4 and node 1 can be calculated to be 10 (15*0.5 + 5*0.5) €/MWh. LMP at node 1 is 15 (25-(15*0.5+5*0.5)) €/MWh. The payments from long-term auction bid winners to the SO are listed in the last row from Table 2. Bidder 1 pays 3750 € to the SO for the 375 FTR between node 1 and node 3 and bidder 5 pays 2500 € to SO for 100 MWh of energy purchase rights. At the same time, SO pays 2000 € to bidder 3 for 100 MWh of energy sale rights.

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Upper bound (MW)	500	150	300	100	300
Lower bound (MW)	200	0	0	0	0
Bid price €/MWh	10	35	20	10	25
Result quantity (MWh)	375	0	100	0	100
Result price (€/MW)	10	0	20	0	25
Payment to SO (€)	3750	0	-2000	0	2500

Table 2 Payment from the bid winners to the SO in the long-term auction

3.1 Scenario 1 under nodal pricing: Low carbon cost and real time load 500 MW

The first scenario assumes low marginal generation cost at node 2 with a cost of 35€/MWh as a base case for comparison. In the day-ahead market, assume that the five bidders take part in auctioning with the same bids as in long-term auctioning. If the network condition remains the same, there will be no change in the bidding result using the same algorithm for the auctioning. As the resulted day-ahead auctioning price is the same as in the long-term auction, the system operator (SO) will pay the same amount to the long-term auction bid winners as the bidders have paid to the SO in the last round. Afterwards, the bid winners in the day-ahead market auctioning pay the SO exactly the same amount as in the long-term auctioning.

In the real-time market, only bilateral contracts and the energy bids are allowed in the optimization process. All the transmission users are paid the locational marginal pricing. All the right holders are cashed out in this final round of market according to real time price. In this scenario, the real time load at node 3 is set to be 500 MWh, which corresponds to the redispatch case in the zonal market. In this study, all the energy bidders and FTR bidders are assumed to be backed by physical dispatch ability. For instance, the bid 1 offer upper value corresponds to generation production limit at node 1. The generation plant at node 1 offers energy sale at 15€/MWh, plant at node 2 with energy sale offer at 35€/MWh and plant at node 4 with energy sales at 20€/MWh in the last round of auction with physical dispatch. The real time market clearing result is shown in Figure 6.

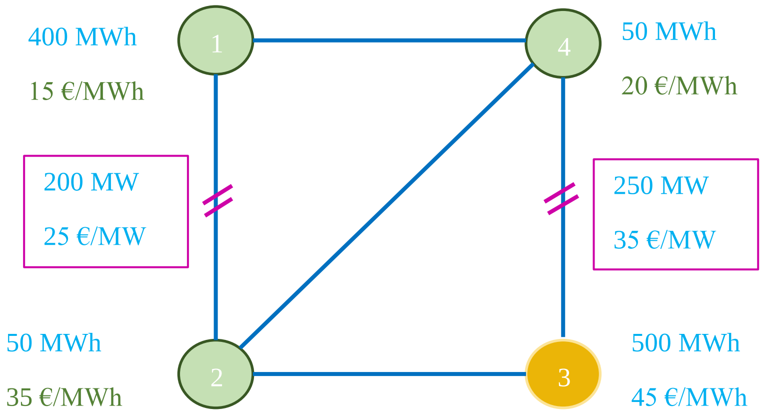


Figure 6 Real time dispatch results

The generator at node 1 will produce 400 MW and the generators at node 2 and node 4 will each produce 50 MW. Under this dispatch pattern, line 1-2 and line 4-3 are congested with a shadow price of 25€/MW and 35€/MW respectively. The LMP at the node 3 is 45 €/MWh. The LMP at node 1, node 2 and node 4 is 15 €/MWh, 35€/MWh and 20 €/MWh respectively.

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Quantity (MWh)	375	0	100	0	100
Price (€/MW)	30	0	20	0	45
Payment to SO (€)	11250	0	-2000	0	4500

Table 3 Payment from the SO to day-ahead bid winners at real time market

With the LMP being 45€/MWh at node 3, the SO receives 22500 € from load. At the same time, the SO pays out 6000 € to generator at node 1 at 15€/MWh, 1000€ to generator at node 4 at 20€/MWh and 1750 € to generator at node 2 at 35€/MWh. There is a surplus of 13750 € as congestion revenue for the SO. This surplus is used to pay bid winners in the previous round of auctioning. The payment from SO to day-ahead bid winners is shown in Table 3. Bidder 1 holds 375 MWh of FTR with a price that equals nodal price difference between node 3 and node 1, so FTR for bidder 1 is worth 30 €/MW. Bidder 1 receives 11250€ from the SO. Bidder 5 that holds energy purchase right at node 3 is paid at the nodal price of 45€/MW and receives 4500€ from SO for the 100 MW right it owns. Bidder 3 who has been paid by the SO for the energy sale contract in the previous auction round needs to pay the SO according to the real-time LMP at node 4. In total, bidder 3 pays the SO 2000€ at the price of 20€/MWh. The total net payment from the SO to the bid winners is 13750€. This equals the congestion revenue from surplus between load and generation payment. Revenue adequacy is reached for the SO, i.e., no revenue short fall for the SO to settle the energy and transmission right bids cleared at day-ahead market. In the long-term, day-ahead auctioning and real-time market, the line 1-2 and line 4-3 are congested with full capacity utilization. The total payment from the user across different market time frames includes the initial payments for obtaining the rights, day-ahead bid payment and right receipt, final load payment and the cashing out of the rights from SO at real time. In this scenario, the net payment from the user across different time frames is 13000 (3750 + 2500 + 22500-11250-4500) €. When the user is entitled the FTR auctioning revenue, in this case the 3750 € FTR payment in the long-term auctioning, the net payment for the ARR holding user is 9250 €.

3.2 Scenario 2 under nodal pricing: high carbon price and load value 500 MW in real time

Under scenario 2, the marginal generator has a higher cost of 80 €/MWh due to high carbon price. The long-term and day-ahead auctioning results stay the same as in scenario 1. Therefore, the long-term auctioning payment from bid winners is the same as in Table *2*. The bid winners in the day-ahead market auctioning pay the SO exactly the same as in the long-term auctioning round and they get paid back this same amount from the SO as right holders.

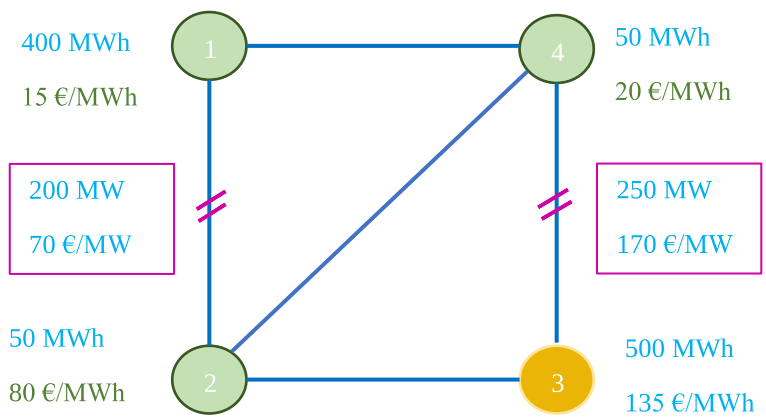


Figure 7: Real time dispatch in scenario 2 under nodal pricing

In real time market, the dispatch is shown in Figure 7. Load at node 3 and generation bid offers at node 1 and node 4 are the same as in scenario 1. Only the plant at node 2 offers energy at 80 €/MWh. The generator at node 1 will produce 400 MW and generators at node 2 and node 4 will each produce 50 MW. Under this dispatch, both line 1-2 and line 4-3 are congested with a shadow price of 70 €/MW and 170 €/MW respectively. The LMP at the hub node is 135 €/MW. The LMP at node 1, node 2 and node 4 is 15 €/MW, 80 €/MW and 20 €/MW respectively. The interconnection in the long-term, day-ahead and real-time market is fully utilized.

The SO receives 67500 € from load at node 3, while it pays out 6000 € to generator at node 1, 1000€ to generator at node 4 and 4000 € to generator at node 2. There is a surplus of 56500 €. The surplus is used to pay bid winners in the day-ahead market auctioning. FTR for bidder 1 is worth 120 €/MW. As Table 4 shows, bidder 1 receives 45000€ from the SO for the 375 MW of FTR it holds. Bidder 5 that holds energy purchase right at node 3 is paid at the nodal price of 135€/MW and receives 13500€ from SO for the 100 MWh right. Bidder 3 who is paid by SO for the energy sale contract in the previous auction round needs to pay to the SO according to the real-time LMP at node 4. In total, bidder 3 pays SO 2000€. The total net payment from the SO to the bid winners is 56500€. The surplus from load and generation payment equals net payment to bid winners. Revenue adequacy is reached for the SO in the day-ahead market, i.e., no short fall of revenues for the SO to settle the energy and transmission right bids.

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Quantity (MW)	375	0	100	0	100
Price (€/MW)	120	0	20	0	135
Payment to SO (€)	45000	0	-2000	0	13500

Table 4 Payment from SO to the previous round bid winners in day-ahead market under scenario 2

If both bidder 1 and bidder 5 represent the user who wants to hedge congestion risk by obtaining FTR and an energy purchase contract or link to the user indirectly as trader or retailer supplying electricity at the load node, how effective do the hedging instruments function? In the following calculation, the price paid or received by bidder 1 and bidder 5 is categorized as the user expenditure. The user will pay 3750€ to obtain 375 MWh FTR and 2500 € for the 100 MWh energy purchase contract in the long-term auctioning. In the long-term and day-ahead auctioning, the user has paid 6250 € for hedging instruments that covers 475 MWh of the total load. In the day-ahead, the user pays and receives the same amount. At real-time, the user at node 3 pays 67500€ for the 500 MWh total load. However, the SO pays back the user 45000€ for the FTR and 13500€ for the energy purchase contract. In total, 58500€ is paid back to the user at real time and this accounts for a significant share of the 67500 € of the load payment at real-time price. In this scenario, the total net payment from the user across different time frames is 15250€. When the user is entitled the FTR auctioning revenue, the net payment for the ARR holding user is € 11500. This scenario calculation shows that in times of large price variations, holding energy and congestion hedging instruments such as FTR in long-term and day-ahead market reduces the risk exposure significantly from user perspective.

3.3 Scenario 3 under nodal pricing: high carbon price and load value 525 MW in real time

This scenario investigates the impact of load deviation between day-ahead and real-time market time frame. Assume at day-ahead time frame, the user estimates the load to be at least 500 MWh and in the real time the load value is 525 MWh. Two bidding strategies by the user are compared. Under strategy A, the user at load 3 that bid both energy purchase and FTR between node 1 and node 3 does not set a minimum value of the sum of FTR and energy purchase at day-ahead market. Only at real time market, the load is set at 525 MWh. Under strategy B, the user at load 3 sets a minimum value of 500 MWh for the sum of FTR and energy purchase.

Strategy A: load-bid-without-setting-a-minimum-value-at-day-ahead-market

Assume under this strategy, the bidding price, lower and upper bounds from the five bidders are the same as in the long-term auctioning market. As shown in Figure *8*,when the load value becomes 525MWh at real time, generator at node 1 will produce 425 MWh and generators at node 2 will produce 100 MWh.

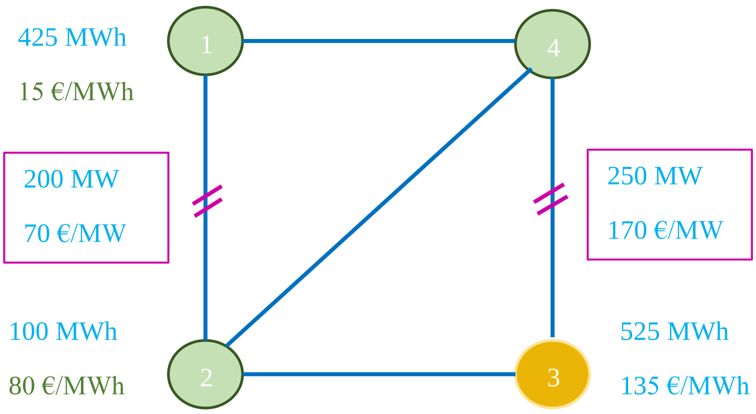


Figure 8 Real time dispatch result in scenario 3 under nodal pricing

In the real time market, both line 1-2 and line 4-3 are congested with a shadow price of 70 €/MW and 170 €/MW respectively. The LMP at the hub node is 135 €/MW. The LMP at node 1, node 2 and node 4 is 15 €/MW, 80 €/MW and 20 €/MW respectively. The SO receives 70875 € from load at node 3, while it pays out 6375 € to generator at node 1 and 8000 € to generator at node 2. There is a surplus of 56500 €. The surplus is used to pay bid winners in the day-ahead market auctioning. The payment to the bid winners is shown in Table 5.

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Quantity (MW)	375	0	100	0	100
Price (€/MW)	120	0	20	0	135
Payment to SO (€)	45000	0	-2000	0	13500

Table 5 Payment from the SO to the bid winners

The total amounts to 56500 €, exactly the same as scenario 2. The surplus from load and generation settlement equals the payment to energy and transmission right bids. Therefore, the revenue adequacy is achieved for the SO. Across different time frames, the user at the load node that represents bidder 1 and bidder 5 accumulates a total net payment of 18625 € (3750 + 2500 + 70875 -45000-13500). When the user holds the ARR that gives back FTR auctioning revenue between node 1 and node 3, then the net payment becomes 14875 €.

Strategy B: Minimum-bids-of-500 MWh-at-the-day-ahead-auctioning-by-bidders-that-represent-load

In the day-ahead time frame, the user has gained better insights of the real time load evolvement. Under this strategy, assume that user estimates the load value to be at least 500 MWh and is determined to secure 500 MWh as a combination of FTR and energy purchase contract in the day-ahead auctioning. Like assumed in all scenarios, bidder 1 and bidder 5 both represent the user at node 3. Bidder 1 observes the long-term auctioning result and submits 375 MWh as the minimum value of its FTR bid. Bidder 5 then submits the energy purchase bid with 125 MWh as its minimum value. The lower bound of 375 MWh FTR and 125 MWh energy purchase contract is a randomly chosen number, but the sum of them adds up to 500 MWh.

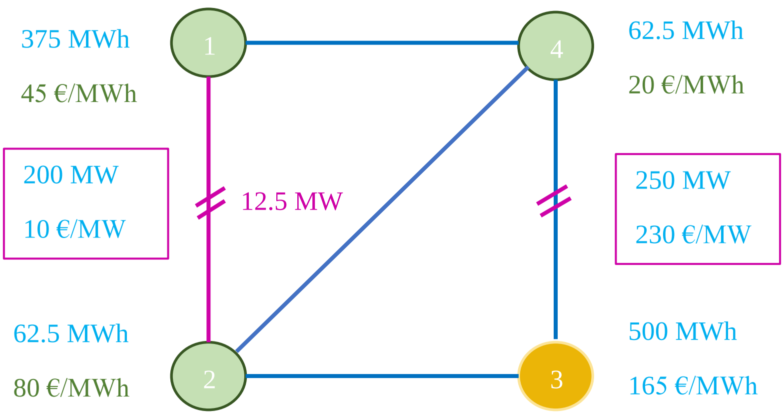


Figure 9 Day-ahead prices with strategy B in scenario 3 under nodal pricing

The day-ahead auction clearing result is shown in Figure 9. Shadow price for line 1-2 is 10€/MW and for line 4-3 is 230 €/MW. The LMP at the hub node 3 is 165 €/MWh. LMP at node 1, node 2 and node 4 is 45 €/MWh, 80 €/MWh and 20 €/MWh respectively. Bidder 1 is awarded 375 MWh FTR. Bidder 2 and bidder 3 are each awarded 62.5 MWh energy sale contract. Bidder 4 obtains 12.5 MW of physical transmission rights. Bidder is awarded 125 MWh of energy purchase contract. The FTR that reflects the price difference between node 3 and node 1 is 120 €/MWh.

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Upper bound (MW)	500	150	300	100	300
Lower bound (MW)	375	0	0	0	125
Bid price (€/MW)	10	80	20	10	25
Quantity	375	62.5	62.5	12.5	125
Resulted Price (€/MW)	120	80	20	10	165
Payment to SO (€)	45000	-5000	-1250	125	20625

Table 6 Payment from the bid winners to the SO in day-ahead auctioning

As Table 6 shows, bidder 1 pays SO 45000€ for the 375 MWh FTR between node 3 and node 1. Bidder 4 pays 125 € to the SO for the 12.5 MW of flow gate rights. Bidder 5 pays 20625 € to the SO for the awarded 125 MWh energy purchase contract. The SO pays 5000 € to bidder 2 for the 62.5 MWh energy sale and 1250 € to bidder 3 for the 62.5 MWh energy sale. In total, the net receipt for the SO is 59500 €.

Payment from the SO to the previous bid winners is listed in Table 7. The payment from the SO to bidder 1 who holds 375 MWh FTR accounts for 45000 €. The payment from the SO to bidder 5 is 16500 € for its 100 MWh energy purchase rights. Bidder 3 pays the SO 2000 € for its 100 MWh energy sale rights. The net payment from SO to previous bid winners is 59500€. There is revenue adequacy for the SO at day-ahead auctioning.

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Quantity (MW)	375	0	100	0	100
Price (€/MW)	120	0	20	0	165
Payment to SO (€)	45000	0	-2000	0	16500

Table 7 Payment from SO to previous round right holders in day-ahead auctions

In the real time market, resulting physical dispatch is the same as in strategy A, 425 MWh generation at node 1 and 100 MWh at node 2. The LMP at node 3 is 135 €/MWh. Shadow price of congested line 1-2 is 70 €/MWh and for congested line 4-3 170€/MWh. LMP at node 1, node 2 and node 4 are 15 €/MWh, 80 €/MWh and 20 €/MWh respectively. The SO receives 70875 € from load. Meanwhile, the SO pays 6375 € to generator at node 1 and 8000€ to generator at node 2. There is a surplus of 56500 € for the SO. The payment by the SO to previous bid winners in real time market is shown in Table 8. The total net payment from SO to bid winners is 56500€. Revenue adequacy is achieved for the SO again.

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Quantity (MW)	375	62.5	62.5	12.5	125
Price (€/MW)	120	80	20	70	135
Payment to SO (€)	45000	-5000	-1250	875	16875

Table 8 Payment by SO to previous bid winners in real-time

An immediate observation can be made from strategy B that nodal prices in the auctions that are financial can be higher than the real time price which reflects the value of the physical usage of electricity. While the user has bid in the day-ahead market with updated load forecast information, the total costs increase compared to strategy A. This is mainly due to the setting of lower boundary, which means the user is willing to pay whatever it takes to obtain the specified rights. The total net payment for the user behind bidder 1 and bidder 5 is 19375 € (3750 + 2500 + 45000+ 20625 – 45000- 16500 + 70875- 45000 – 16875). When the user is allocated the ARR to be rewarded the long-term FTR auction revenue, the net payment becomes 15625 €.

The intertemporal relationship of the cost components for the user can be clearly observed in equations in Appendix. An interesting finding is that the total payment made by the user employing congestion hedging instruments in the long-term and day-ahead auctioning can be decomposed into costs in different time frames. The user pays the real time LMPs of the load node for the incremental load value compared to the sum of FTR and the energy contract procured in the previous auction. At the same time, these rights obtained with the quantity and price determined in the previous auctioning round are paid back with real-time price. For instance,1 MWh of energy from node 1 to node 3 can be interpreted as the sum of real time nodal price at node 1 and the FTR price the user pays at day-ahead auctioning. In the case of FTR, what the user pays at day-ahead market can further be linked to its long-term right bid and payback. A consistent breakdown of costs creates a settlement system that rewards the deployment of hedging instruments for market players. The effectiveness for hedging congestion risk relates to the ability of user to forecast the load, its estimation of the market condition and also network congestion in bidding round.

Nodal pricing	Scenario 1	Scenario 2	Scenario 3 A	Scenario 3 B
Total cost for user without ARR rewards (€)	13000	15250	18625	19375
Total cost for user with ARR rewards (€)	9250	11500	14875	15625

Table 9 Total payment for the user at node 3 without or with the ARR reward

The total payment from user at node 3 with or without the ARR reward is summarized in Table 9 . Several policy implications can be observed from the three scenarios in nodal pricing:

- Revenue adequacy is always achieved for system operator under the nodal pricing.
- A major part of the congestion risk in the real time market is hedged for user in the case study by obtaining FTR and energy purchase contract in the long-term and day-ahead market auctions.
- The total payment of user has clear cost components in each time frame. In essence, the user pays at the locked-in price for the bids secured at previous auctioning round and pay for the real-time LMP for the incremental amount of energy not covered by any hedging instruments. The pricing rule is consistent across different markets.

4 Joint energy and transmission right auction under zonal pricing

4.1 Long-term, day-ahead market coupling, redispatch and balancing in the zonal market

In this section, first a joint energy and transmission right auction is implemented in the long term and day-ahead market coupling. Then the redispatch and balancing take place after day-ahead market gate closure. The market process and involved actors are illustrated in Figure 10.

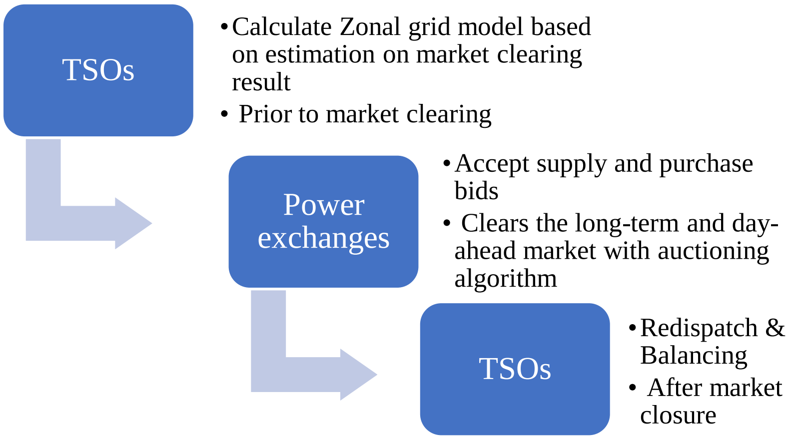


Figure 10 Market process of the long-term, day-ahead and redispatch& balancing in zonal pricing

The development of long-term market and effectiveness of its hedging instruments is the focus of this study. However, long-term market is not only about the long-term time frame, the payback of the energy and transmission rights procured by market participants in long-term auction are priced at later auction round. In this simplified case study to illustrate market logic, the long-term market is directly linked to day-ahead market coupling in the zonal model as day-ahead market coupling serves as the backbone of EU internal market. The envisioned institutions and their responsibilities in the long-term joint auction are made similar to the arrangements in current day-ahead market coupling. Day-ahead market is treated as the real-time market in the nodal pricing with physical dispatch.

Currently, a cross-border intra-day market exists in Europe. Two forms of market mechanisms coexist in this time frame: auction and continuous trading. However, the interconnection capacity under the continuous trading is allocated on a first come, first served basis. There is no optimization of interconnection capacity in this design. Therefore, the intra-day market is not included in the calculation. In the case study, deviation of load from forecast only appears and thus is dealt with in the balancing time frame.

After gate closure of the short-term market, redispatch and balancing are performed by the SO as the single buyer. In the case study, the schedules from day-ahead market clearing are submitted to the TSO to evaluate whether they are feasible. Redispatch is the activity by the TSO to dispatch up or dispatch down some generation or load, in order to alleviate network congestion from the short-term market schedule. The redispatch happens before real time.

Balancing is organised by TSOs to correct deviations between previously predicted generation and load volume that are bid into short-term market and the real time values. Unlike the long-term or spot market organised by power exchanges where the buyers bid their price preference, the TSOs would always need to acquire enough electricity to meet instantaneous load and ensure the power flows are within the network capacity limit.

4.2 Grid representation and market clearing mechanisms

In this section, the joint energy and transmission right auction is implemented in the long-term market under zonal pricing. Governance structure of the joint auctioning in the long-term time frame follows the currently implemented day-ahead market coupling in Europe. Electricity market is split into zones with different TSOs that are responsible for grid control in each zone. TSOs make a common network model that is a simplified zonal model of the full grid and pass it to the power exchanges. Within a bidding zone, the power exchange accepts supply/demand bids and clears the market. The bidding zones are formed by aggregation of nodes to act as virtual nodes in the JETRA. Zones are linked by the interconnection lines. The zonal PTDF values that give the distribution of power flow from a unit change of net injection or withdrawal of a specified zone on the interconnection lines defines the relationship of inter-zonal trade and interconnection flow.

The auction objective is to maximize bid values while respecting the energy supply and demand equilibrium as well as interconnection flow limit. The shadow prices are calculated as the dual variable of the inter-zonal line flow constraint, while the dual variable from energy balance equation gives the hub zone price, which is the demand zone in the case study. The hourly prices are determined in market clearing while taking into account the inter-zonal flow limits. The bilateral contracts are traded outside of the power exchange. All the sellers within a bidding zone receive the same zonal price and all the buyers pay the same zonal price.

This case study uses a simplified network representation in long-term auctioning following the transfer capacity (TC) case studies by D'Aertrycke and Smeers [13]. Equation 5 shows that zonal PTDF on the interconnection lines can be derived from nodal PTDFs and generation demand shift keys (GDSK). Generation demand shift keys represent the nodal change of generation or demand level in proportion to the zonal net injection/withdrawal change. In day-ahead market coupling, TSOs use a base case usually from two days ahead (D-2) in flow-based market coupling to calculate the generation shift keys related to the base case generation load patterns [14]. Before the clearing of long-term auction, the TSOs do not acquire supply and offer bidding information. The unclarity of the exact location of supply, purchase bidders or the exact injection and withdrawal nodes of financial transmission right bidders needs to be considered while constructing the simplified grid model for the long-term market clearing.

$$PTDF_{l,z} = \sum_n PTDF_{l,n} * GDSK_{n,z} \quad (5)$$

Where:
$PTDF_{l,z}$ denotes the zone to line power transfer distribution factors of zone z on interconnection line l.
$PTDF_{l,n}$ is the node to line power transfer distribution factors on interconnection line l.
n refers to the nodes within zone z.

Computation of a well performing GDSK that gives accurate zonal network representation is linked to how close the base case represents for the actual generation load pattern. The base case is the system snapshot chosen by the TSO to calculate the zonal PTDF, usually at zero zonal export or import condition. In particular with large scales of intermittent renewable energy resource, forecast of the GDSK a few years prior to the electricity delivery time will be a very challenging task. Moreover, the network operational aspect of long-term forecast may compound with new generation investment uncertainties. There might be new generation commissioned in unknown locations in a few years, which makes the GDSK forecast approach less suitable. In the long-term market, we do not use a base case approach since finding a representative base case a few years ahead of market operation is very difficult, if ever possible. Given the high uncertainties in the long-term time frame, the worst-case approach taken by Smeers to determine interconnection transfer capacity under TC model is adopted for long-term auction to determine the zone-to-zone transaction volume limit and zonal PTDF values.

The method applies the same nodal PTDF values from the most critical transaction for long-term energy sale/purchase offers and inter-zonal FTR, in order to calculate flow on the interconnections. The most critical transaction refers to the injection and withdrawal pattern from the node pair located in two bidding zones that has the largest PTDF values on interconnection lines. In addition, the impact of intra-zonal transaction on interconnection capacity needs to be taken into account when setting interconnection flow limit in the grid model.

Unlike the auction under nodal pricing, the flow limit under zonal pricing does not include an internal network bottleneck. In reality, the impact of cross-border network impact on the internal network is reflected in the critical branch identified by the TSOs. However, Van den Berghe et al point out that transparency of setting critical branch flow parameters is subject to questions [14]. The selection of critical branches could vary substantially depending on the criteria. This case study uses a simplified flow-based market coupling grid representation that does not calculate the impact of critical branches. The network constraint consistency issues investigated can be extended to cases where critical branches can not be effectively identified for all time frames. Here we focus on the GDSK uncertainties in the simplified inter-zonal model and inter-temporal market consistency issue.

For day-ahead market coupling, the objective function is to maximize the social welfare while respecting constraints of the allowed inter-zonal trade volume. The zonal network representation is made by the TSO as a result of the forecast for market clearing. In this timeframe, the GDSK forecast uncertainties can be caused by many reasons. For instance, the linearity of the increase or decrease of generation production at certain node in relation to the base case may not be guaranteed as a result of generation plant capacity limit. The intermittency of renewable energy resources can also make the generation forecast more difficult, thus predicting the nodal generation or load change in proportion to net export/import becomes more challenging. In the next subsection, the GDSK in day-ahead market time frame is made by excluding some unlikely transaction patterns and putting some safety margin with load distribution in the GDSK formation. The impact of intra-zonal trade on the interconnection is also calculated while constructing the inter-zonal network constraint. The net position and market price are calculated by power exchanges.

As the intra-day market uses continuous bids, there is no uniform zonal price or optimization of interconnection capacity in the European intra-day time frame. Therefore, the day-ahead market outcome is used to settle the last round of joint energy and transmission right auction. After the day-ahead market closure, the case studies directly come to redispatch and balancing phase. Different levels of cross-border redispatch coordination have a significant impact on the system cost as the studies from Oggio et al and Kunz et al show respectively [15][16].

Two redispatch and balancing market models are implemented in the case study. The first model follows a national redispatch approach that only allows TSOs to use the resources within their bidding zone to alleviate internal network congestion. In this case, the interconnection capacity utilization is kept unchanged from the day-ahead market clearing. Only the intra-zonal network capacity limit is imposed as the constraint for altering generation load patterns.

The second model implements a deeply integrated cross-border redispatch and balancing mechanism. Under this approach, the TSOs coordinate as if there is a single system operator across the borders that can optimize the generation resources and network capacity to minimize the system cost. The real flow on the interconnection as a result of day-ahead schedule is calculated and the remaining interconnection capacity can be utilized in the redispatch process. At the same time, the intra-zonal constraint is included in the optimization to alleviate the congestion on the overloaded lines.

A simplified assumption is made here regarding redispatch cost: 1) the TSO pays the generation that increases production according to its original bidding price in day-ahead market; 2) the generation that is required to decrease the production pays back the avoided generation costs to the system operator, which is approximated by the generation bid price in day-ahead market.

4.3 Scenario 1 under zonal pricing: Low carbon cost and real time load 500 MW

This section constructs a case study with low carbon price and low marginal generation cost for the zonal market. In order to fulfil the revenue adequacy requirement of enlarging the transmission right portfolio in the later round of joint auction, larger portfolios of transmission rights should be made available from long-term to day-ahead market. This is achieved by relaxing the constraints in GDSK calculation assumption, so that the zonal PTDF values are smaller in the day-ahead compared with long-term market. In both time frames, the imperfect GDSK estimation leads to market clearing results that deviate from the most economical transaction patterns in the nodal system.

Assume the same five bidders participate in the auction and offer the same price and lower upper limits as in the nodal case in Figure 4:

- Bidder 1 bids for financial transmission right from zone west to zone east at 10 €/MWh with lower bound of 200 MWh upper bound of 500MWh.
- Bidder 2 bids for energy sale from zone east at 35 €/MWh with upper bound of 150 MWh.
- Bidder 3 bids for energy sale from zone east at 20 €/MWh with upper bound of 300 MWh.
- Bidder 4 bids for physical transmission rights between zone west and zone east at 10 €/MW at 10 €/MW with upper bound of 100 MWh.
- Bidder 5 bids for energy purchase from zone east at 25 €/MWh with upper bound of 300 MWh.

Using the model of O’Neil et al, the joint auctioning can be organized between two zones. The system operator in the zonal model is the TSOs in each bidding zones. Examining the network topology, the internal transaction within zone east that is likely to create congestion on the interconnection line 1-2 is the transaction from node 4 to node 3. For the interzonal transmission and energy auction in the long-term time frame, a conservative view of the internal transaction is needed to ensure the system security.

The most critical scenario for interconnection line 1-2 with capacity limit is the transaction from node 1 to node 2, whose PTDF on the positive direction of interconnection line 1-2 is 0.625. Implicitly, using this zonal PTDF assumes all the transaction from zone west to zone east will be withdrawn at node 2. The maximal transaction allowed from zone west to zone east can be calculated to be 320 MWh (200/0.625). The energy sale and purchase within zone east is assumed to have the same zonal PTDF value 0.125 on the positive direction of interconnection line 1-2, which equals the nodal PTDF from transaction from node 4 to node 3. PTDF values of the five bidders are displayed in Table 10.

	Capacity (MW)	Bid 1	Bid 2	Bid 3	Bid 4	Bid 5	Shadow price (€/MW)
Line 1-2	200	0.625	0.125	0.125	1	0	16
Line 2-1	200	-0.625	-0.125	-0.125	0	0	0
Line 1-4	400	0.375	-0.125	-0.125	0	0	0
Line 4-1	400	-0.375	0.125	0.125	0	0	0

Table 10 PTDF of the bidders in the long-term auction under zonal pricing

The dual variable of the flow constraints gives shadow price on link 1-2: 16 €/MW. The dual variable of energy balance equation gives zonal price at demand zone east: 25 €/MWh. Using equation 5.4, the price of FTR for bid 1 can be calculated: 10 (16*0.625) €/MW. The zonal price for west zone is 15 (25-16*0.625) €/MWh.

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Upper bound (MW)	500	150	300	100	300
Lower bound (MW)	200	0	0	0	0
Bid price (€/MW)	10	35	20	10	25
Quantity	260	0	300	0	300
Price (€/MW)	10	0	25	0	25
Payment to SO (€)	2600	0	-7500	0	7500

Table 11 Payment from bid winners to SO in the long-term auctioning

With assumed interzonal PTDF of 0.625 from zone west to zone east, the resulting flow on interconnection line 1-2 is 200 MW (260*0.625 + 300*0.125). Rewarded FTR to bidder 1 is 260 MWh and energy sale offer to bidder 3 is 300 MWh. Bidder 2 and bidder 4 do not get their bid. 300 MWh energy purchase from bidder 5 is accepted. Payment from bidders to the SO can be summarized in Table 11. Bidder 1 pays 2600 € to the SO and bidder 5 pays 7500 € to the SO. At the same time, bidder 3 receives 7500 € from the SO for its energy sale.

The day-ahead market adopts simplified flow-based market coupling algorithm and the clearing result is used to settle long-term auction bids. For the day-ahead market, the price formation in the two zones under scenario 1 can be written as:

$$P_W = 15 \quad (6)$$

$$P_e = \begin{cases} 20, & q_e \leq 300 \\ 35, & 300 < q_e \leq 450 \end{cases} \quad (7)$$

$$q_W = e_x \quad (8)$$

$$q_e = 500 - e_x \quad (9)$$

Equation 6 can be rewritten to express price in zone east as a function of the net export from zone west:

$$P_e = \begin{cases} 20, & e_x > 200 \\ 35, & 50 \leq e_x \leq 200 \end{cases} \quad (10)$$

Market coupling objective function maximizes the social welfare while taking into account of the maximal allowed inter-zonal transaction:

$$Max \int_0^{288.9} P_E(e_x)\, de_x - \int_0^{288.9} P_W(e_x)\, de_x \quad (11)$$

Where:
P_w, P_e are the prices in zone west and zone east respectively.
q_w, q_e are the production in zone west and zone east respectively.
e_x is the export from zone west to zone east.

The price level in zone west is often lower than zone east. The TSOs estimate that the inter-zonal transaction will be from west to east. The internal transaction from node 4 to node 3 can create flows on the interconnection line 1-2. Bid 2, bid 3 and bid 5 as energy supply/purchase bids in zone east can create interconnection flows, which in turn have an impact on the allowed inter-zonal transaction volume. In the case study, an assumption is made that the internal transaction in east zone follows the pattern from node 4 to node 3. Another assumption made for grid model construction is that the internal transaction within zone east is 300 MWh. The resulted flow from internal transaction on the interconnection 1-2 is 37.5 MW. On the positive direction from node 1 to node 2, the remaining capacity for inter-zonal trade is 162.5 MW. On the negative direction of the line, the remaining capacity becomes 237.5 MW. On the positive direction of line 4-1, the remaining network capacity for inter-zonal trade is 362.5 MW. On line 1-4, the remaining network capacity for inter-zonal trade is 437.5 MW. The maximal net export from zone west to zone east can be derived to be 288.9 (162.5/0.5625) MWh.

In this case study, a simplified approach is used to construct GDSK. The approach resembles heuristic method in practice and takes a safety margin into account to reflect the uncertainties that arise from load locations and distributions. Suppose that the TSOs conclude from analysing historical data that node 4 can be excluded as injection node in transactions from zone west to the zone east and also that the load is likely to be distributed between node 2 and node 3. Node 3 is usually the main load centre. This information can be used to translate into inter-zonal PTDF value for day-ahead time frame. A more conservative assumption is used here such that the withdrawal in zone east from net import is equally distributed between node 2 and node 3. With the generation demand shift key set by the assumption, we can calculate the inter-zonal PTDF value: 0.5625 (0.625*0.5+0.5*0.5). The intra-zonal PTDF values of zone east on line 1-

2 take the value from transaction between node 4 and node 3: 0.125. Similar to the joint auctioning, the hub zonal price is the dual variable of the energy balance equation. The shadow price of the inter-zonal transmission link is given by the dual variable of the power flow constraint. Prices of other zones can be derived by the inter-zonal PTDF relations in equation 5.4 by treating zones as virtual nodes. All the buyers pay the same zonal prices and the purchase bids that are equal or higher than the zonal prices are accepted. The inter-zonal PTDF in the day-ahead market can be represented in Table 12.

	Capacity (MW)	Bid 1	Bid 2	Bid 3	Bid 5	Shadow price (€/MW)
Line 1-2	162.5	0.5625	0	0	0	8.89
Line 2-1	237.5	-0.5625	0	0	0	0
Line 1-4	400	0.4375	0	0	0	0
Line 4-1	400	-0.4375	0	0	0	0

Table 12 Zonal PTDF values in the day-ahead market clearing

The resulting dispatch is shown in Figure 11. Generation in zone west produces 289 MWh and generation in zone east produces 211 MWh. It is important to note that the 200 MW on interconnection line 1-2 is the estimated flow using the PTDF values and assumptions at the time of day-ahead market clearing.

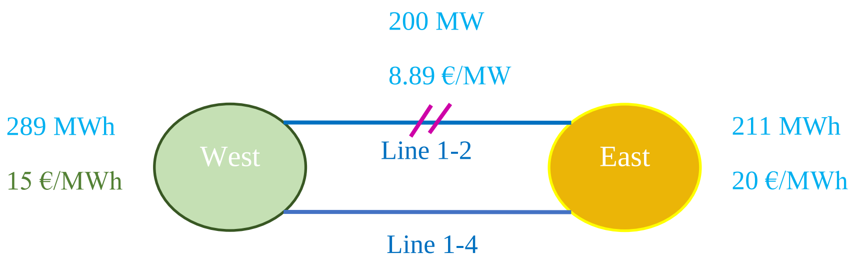


Figure 11 Day-ahead market clearing result under zonal pricing

The shadow price of congested lines determines the price spread between zones. Zone east has a price of 20 €/MWh and line 1-2 has a price of 8.89 €/MW. The FTR between zone east and zone west is 5 (0.5625*8.89) €/MWh. The price in zone west is 15 (20-5) €/MWh. Payment from generation and load to the SO is summarized in Table 13. Load in zone east pays 10000 € for the 500 MWh demand. The generator at node 4 in zone west receives 4220 €, while the generator at node 1 in zone east receives 4335 €. There is a surplus of 1445 € for the SO.

Type	Generation	Generation	Generation	Load
Zone	Zone west	Zone east	Zone east	Zone east
Quantity (MW)	289	0	211	500
Price (€/MW)	15	0	20	20
Payment to SO (€)	4335	0	4220	10000

Table 13 Generation and load payment to the SO at day-ahead market

Payment from the system operator to previous auction winners in the day-ahead market is shown in Table 14. The SOs pay 1300 € to bidder 1 who holds 260 MWh FTR from the long-term auction and pays 6000 € to bidder 5 for holding 300 MWh energy purchase rights. Meanwhile, bidder 3 pays back the SO 6000 € for the 300 MWh of energy sale rights. The total net payment for the SO in day-ahead time frame for the previous auction winners is 1300 €. The surplus of 1445 € can cover the net payment to bid winners in previous around. Revenue adequacy is achieved at day-ahead time frame.

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Quantity (MW)	260	0	300	0	300
Price (€/MW)	5	0	20	0	20
Payment to SO (€)	1300	0	6000	0	6000

Table 14 Payment from the SO to bid winners in day-ahead market

However, neither the long-term energy and transmission right auctioning nor the day-ahead market coupling have considered the internal network bottleneck under zonal pricing. After gate closure, the system operator will assess the feasibility of day-ahead market clearing outcomes by calculating the resulting load flows on the network elements. When the estimated power flow exceeds the limit of network elements, the system operator can alter the scheduled generation or load pattern from day-ahead market, in order to relieve congestion. Some generators that have not been scheduled in the market coupling since their costs are higher than the market clearing price are required to dispatch up and some generators that have been scheduled to produce in day-ahead market are required to reduce their production.

In scenario 1, real-time load does not deviate from the forecasted value after gate closure of the day-ahead market. Therefore, only redispatch by the TSOs is required. The resulting flow from day-ahead market scheduling will be 276.4 MW on line 4-3, which has a limit of 250 MW. To avoid the physical congestion, a redispatch based on cost minimization is conducted.

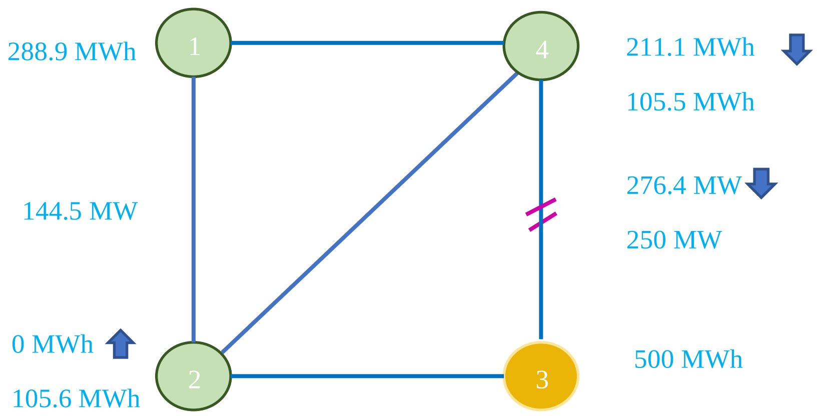


Figure 12 National based redispatch

With a national redispatch approach, the inter-zonal transaction and the associated inter-zonal capacity utilization is kept unchanged from day-ahead market. The eastern zone TSO with the congested internal line only has access to resources located in zone east. The generator at node 4 will decrease from 211.1 MWh to 105.5 MWh, while the generator at node 2 will start from zero and produce 105.6 MWh. While the flow on intrazonal line 4-3 becomes 250 MW after redispatch, the flow on interconnection line 1-2 is 144.5 MW.

The TSO pays 3696 € to the generator at node 2 for the 105.6 MWh it redispatches at 35 €/MWh and the generator at node 4 pays back 2112 € to the SO for the avoided 105.6 MWh generation at 20 €/MWh. As a result of national based redispatch, system cost will increase by 1584 €. The 145 € left for the TSO after day-ahead settlement with bid winners is not sufficient to cover the redispatch cost. The redispatch will need to be born by grid users. In this case study, we assume the redispatch costs are ultimately born by the user at node 3. Similar to the nodal pricing setting, assume the user at load node represents bid 1 for FTR and bid 5 for energy purchase contract from long-term to day-ahead market, the total net cost incurred to the user is 14384 €. When the user holds ARR that gives back the FTR auctioning revenue between zone west and zone east, then the total amount paid by the user is 11784 €.

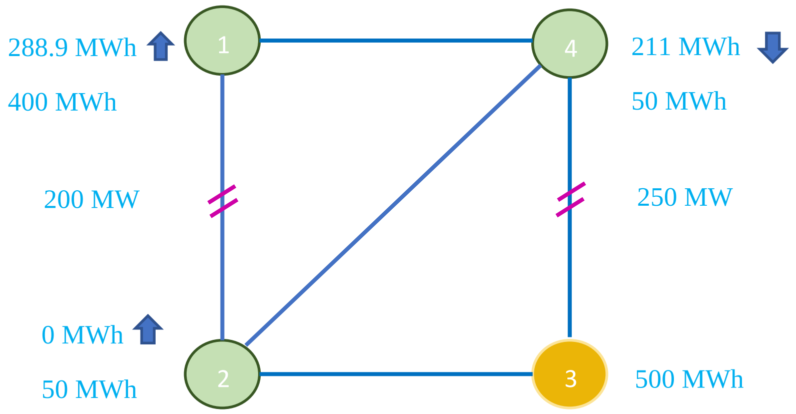


Figure 13 Integrated cross-border redispatch result

As Figure 13 shows, when a cross-border redispatch is conducted, the TSOs will require the generator at node 1 to increase generation by 111 MWh, the generator at node 2 to increase 50 MWh and the generator at node 4 to decrease 161 MWh. To account for the added generation cost by dispatching up plant at node 1 and node 4 as well as avoided costs by dispatching down generation at node 3, a net cost of 195 € is incurred in redispatch. Revenue adequacy is breached for the TSO. The total net payment by the user from long-term auctioning to redispatch is 12995 €. When the user holds ARR that gives back the FTR auctioning revenue between zone west and zone east, then the total amount paid by the user is 10395 €.

4.4 Scenario 2: high carbon price and load value 500 MW in real time

Under scenario 2, the long-term joint auctioning and day-ahead market coupling results will stay the same as scenario 1. Therefore, the payment between the bidders and the SO at long-term and day-ahead time frames are the same as scenario 1. After the day-ahead market clearing, estimated flow on line 4-3 is 276.4 MW and redispatch by the TSO is needed. Under national based redispatch, the same redispatch volume is needed at node 4 and node 2 as in scenario 1. Generator at node 4 will be required to reduce its generation from 211 MWh to 105.5 MWh and pays the TSO 2112 € for avoided generation cost. Generator at node 2 will be asked to produce 105.6 MWh and is paid 8448 €. The additional cost for the TSO is 6336 €.

In the long-term auctioning, payment to the SO from bidder 1 and bidder 5 that represent the user at node 3 is 2600 € and 7500€. In day-ahead market, the user gets paid 1300 € for the FTR and 6000 € for the energy purchase rights. At the same time, the user pays 10000 € to the SO as load payment. After the gate-closure of day-ahead market, the user further pays 6336 € under national based redispatch. In total, the user pays 19136 € across all time frames. When the user is awarded the FTR auctioning revenue for holding ARR, it will need to pay 16536 €.

When cross-border redispatch is conducted, the TSO will require the generator at node 1 to increase generation by 111 MWh, the generator at node 2 to start and increase 50 MWh and the generator at node 3 to decrease 161 MWh. The result is the same as in Figure 13 .To account for the added generation cost by dispatching up plant at node 1 and node 4 as well as avoided costs by dispatching down generation at node 3, total cost 2445 € is incurred in redispatch.

Compared to redispatch within the bidding zones, the system cost of an integrated cross-border redispatch is significantly reduced. However, it is important to note that neither the national based nor cross-border redispatch costs covers the transmission usage tariff for internal network in the redispatch process. The interconnection link 1-2 will now be fully utilized. In this case study, node 1 is a zone by itself. In a larger system, internal network congestion may also be induced in the zones with dispatching up generations. Compared with the national redispatch approach, the beneficiaries of the integrated redispatch are generator 1 at node 1 and consumer at node 3. As opposed to the national redispatch, the dispatching up volume for generator at node 2 will be reduced and the total dispatching down generation at node 4 will be increased in the integrated redispatch. With welfare winners and losers locating in different zones that are not conform to national borders, agreeing the allocation of cross-border redispatch cost is likely to be very difficult, when a market mechanism that sends price signals with spatial granularity is absent.

The total cost for the user at node 3 in the integrated redispatch accounts for 15245 €. When the user is given back auction revenue for holding the ARR, a total amount of 12645 € is paid. The FTR pay back to the user from long-term market participation will be more limited compared with the nodal case study, since the availability of FTR is constrained by the zonal grid representation. From the user perspective, the FTR payback to hedge the congestion risk as a result of market mechanism is more transparent than allocation rules for system cost after the market closure.

Some immediate observations can be made in comparison with scenario 2 under nodal pricing. The long-term auctioning market has adopted virtual node system that aggregates nodes into zones. The forward contracts that are priced based on the zonal pricing with only inter-zonal constraints that can not hedge against the intra-zonal congestion costs. The cost to alleviate intra-zonal congestion incurs since low-cost generations that are dispatched in the day-ahead markets need to reduce production and high-cost generation is required to increase generation. This scenario shows that when the marginal generator has higher cost, the unhedged redispatch costs increases significantly for the user that holds FTR and forward energy contracts.

4.5 Scenario 3: high carbon price and load value 525 MWh in real time

In scenario 3, the high carbon price assumption that implies high marginal generation cost is kept. In addition, the load in real time rises to 525 MWh, which requires balancing from the TSOs. Balancing refers to the service the TSO uses to keep the system stable within predefined frequency range. When the generation production or the load deviates from the day-ahead or intra-day market schedule, there arises the need to acquire additional energy to keep the energy balance in system. In the day-ahead auctioning, the market clearing results in 288.9 MWh generation production from node 1 and 211.1MWh production from node 4. This set of dispatch will lead to 276.4 MW power flow on the intra-zonal line from node 4 to node 3. The TSOs will have to conduct redispatch to relieve the transmission congestion as in scenario 2. After gate closure, the load has increased 25 MWh and the TSOs also needs to manage this imbalance by the use of reserves. To calculate the national based redispatch and balancing within zone east, the inter-zonal transaction and the interconnection utilization is kept unchanged from day-ahead market clearing. The internal network capacity limits and energy balance in the system are used as constraints for cost minimization.

As Figure 14 shows, the generator at node 4 reduces its generation from 211.1 MWh to 78.8 MWh and generator at node 2 starts to produce 150 MWh. At the point where the intra-zonal network constraint is reached at 250MW and generator at node 1 in zone east reaches its capacity limit, there will be 7.22 MWh of energy not served at node 3. With a loss of load cost at 1000 €/MWh, the total loss of load cost amounts to 7220 €. The additional costs for generation at node 2 equals 12000 € and the avoided costs for generator at node 4 equals 2646 €. The redispatch and balancing costs for the user is 9354 €. The total redispatch, balancing and energy not served costs to the TSO amounts to 16574 €.

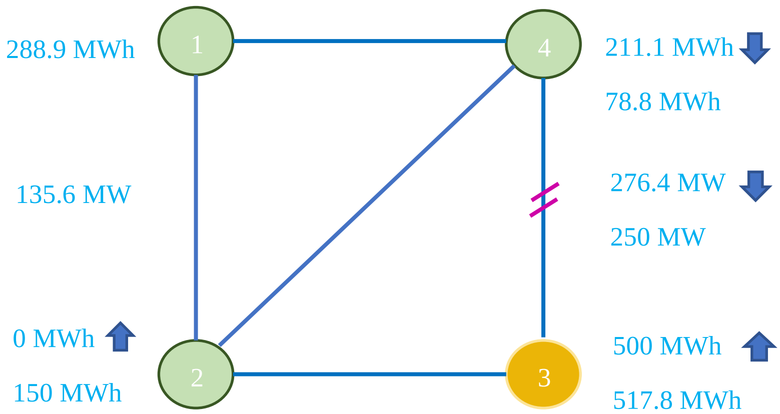


Figure 14 National based redispatch and balancing result

In the long-term auctioning, the payment from bidder 1 and bidder 5 who represent the user at node 3 is 2600€ and 7500€. In day-ahead market, the user gets paid 1300 € for its FTR and 6000 € for energy purchase contract. At the same time, the user pays 10000 € to the SO as load payment. After gate-closure of day-ahead market, the user further pays 9354 € for redispatch and balancing cost. Under the national based redispatch, the user pays 22154 € in total across all time frames in scenario 3 under zonal pricing. At the same time, there is 7.22 MWh of energy not served. The total payment for the user that is rewarded the FTR auction revenue for holding the ARR is 19554 €.

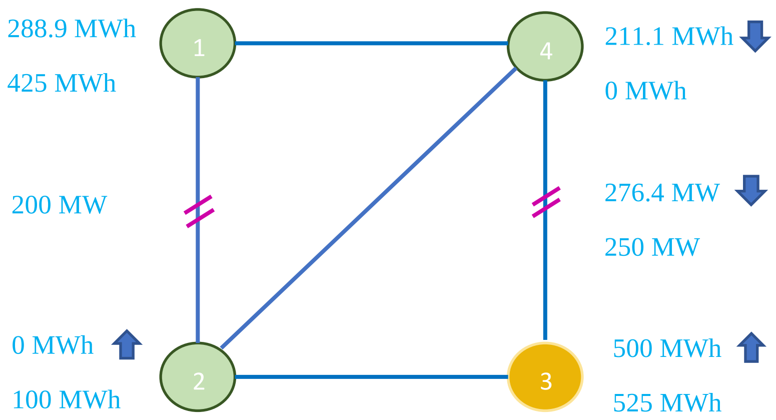


Figure 15 Integrated cross-border redispatch and balancing result

As Figure 15 shows, in an integrated cross-border redispatch and balancing, generation plant at node 1 increases production by 135.8 MWh. Generation plant at node 2 increases generation by 100 MWh and the plant at node 4 decreases by 211 MWh. The total cost for the cross-border redispatch and balancing is 5820 € (136*15+100*80 – 211*20). The user pays 18620 € in total across all time frames. When the user that holds ARR is given back the FTR auctioning revenue in the long-term market, the total payment becomes 15020 € under zonal pricing, which is even lower than the total amount 14875 € for the ARR holding user in strategy A and 15625 € for the ARR holder in strategy B under nodal pricing.

Zonal pricing	Scenario 1 national redispatch	Scenario 1 integrated redispatch	Scenario 2 national redispatch	Scenario 2 integrated redispatch	Scenario 3 national redispatch& balancing	Scenario 3 integrated redispatch& balancing
Total cost for user without ARR rewards (€)	14384	12995	19136	15245	22154 (7.2 MWh Energy not served)	18620
Total cost for user with ARR rewards (€)	11784	10395	16536	12645	19554 (7.2 MWh Energy not served)	15020

Table 15 Total cost for user with and without ARR under zonal pricing

The total cost for users across different time frames are summarized in Table 15. Several observations and policy implications can be made from zonal case studies:

- Under zonal pricing, the FTR cleared in the long-term joint auction is significantly reduced as a result of the conservative zonal grid model regarding the inter-zonal flow limit and the inter-zonal trade relationship.

- Under national based redispatch, the overall cost the user at load node pays is higher as opposed to nodal pricing. By comparing the total costs paid by the ARR holders, the difference in user payment between the zonal and nodal pricing becomes higher.

However, the redispatch that is based on generation or load cost still does not price the internal network use. The difference in total user payment under nodal and zonal pricing could be enlarged when the use of internal network is paid by the user in east zone.

- Cross-border redispatch and balancing can lower the total system cost significantly under zonal model. The total payment of the user may get closed to nodal system in this arrangement. However, several issues arise. Implementing integrated cross-border redispatch requires centralised operation that coordinates market and system operation across borders. In addition, the need of cost allocation by negotiated rules arises. As far as the pricing rule for redispatch is concerned, this research assumes that the power plants that are dispatched down need to pay back the system operator their avoided generation costs. The welfare losing market players in the process of redispatch may prefer to have the day-ahead market functioning properly and send efficient price signal at first place, otherwise a compensation scheme might be expected. Furthermore, the revenue adequacy for system operator is breached with the national based and integrated cross-border redispatch. The market player can not effectively hedge the risk of the redispatch cost as they are incurred after the market closure.

5 Conclusion

Long-term wholesale market as well as bilateral contracts are important components of cross-border electricity market. In light of the accelerating decarbonization, long-term electricity market that sends stable price signals gains increasing attention. Given the history of liberalization in electricity sector, the long-term transmission rights across borders that play a determinant role in shaping market are underdeveloped in Europe. Looking back, prioritized long-term transmission access had been examined by European institutions with critical views. Is there another way to design long-term transmission rights to facilitate the market development at this time frame without creating barriers for new entrants for competition?

The joint energy and transmission right model developed by O'Neil et al is proposed to answer the question in this research. Firstly, the simultaneous optimization of energy and transmission usage promises economic efficiency. In addition, the model makes the allocation of financial and physical transmission right both feasible in the auction. Secondly, an important aspect that makes a difference in the performance of hedging instruments or cost structure for network users is whether the market clearing result is physical or financial. One advantage of introducing a multi-settlement system as proposed in the model is that market clearing before real-time does not interfere with physical dispatch. Only the clearing of real-time market has physical commitments. This could enable the network user to financially hedge the congestion risk while allowing system operator to optimize the resources of the whole system at the time of delivery.

The success of developing the long-term market depends not only on implementing an efficient auction model, but also on the underlying market structure. This research investigated compatibility of current market design and governance with long-term market development from two dimensions: the consistency between market in different time frames and consistency between intra and inter bidding zone market design.

- Spatial and temporal dimensions are navigated by comparing market outcome with grid models reflecting different pricing granularity in different time frames. It is important to note that in the European electricity market, the market and network operation are separated. From day-ahead market coupling to balancing, physical network capacity usage is allocated sequentially in different market time frames. For instance, the physical capacity allocated to day-ahead market can not be liquidated without cost and be granted in other time frames. Given the nature of multi-settlement system in the joint auction model, this study assumes awarded bids of financial transmission rights, physical transmission rights and forward energy contracts in the zonal market are made financial in the long-term time frame. Once the network utilization in day-ahead market becomes physical commitment, the final payback to the transmission right holders or forward energy contract will be settled at day-ahead price. Therefore, day-ahead market coupling takes the important role to connect the long-term and short-term market. In other words, the governance revolving the day-ahead market coupling has a fundamental influence on the development of markets in the other time frames.

- The case study shows that the volume of FTR that can be made available to market participants between the same injection and withdrawal location in the long-term auction is much more constrained under zonal pricing as opposed to that of nodal pricing. A simplified zonal grid model is constructed by the TSOs prior to market opening and passed to power exchanges where purchase and offer bids are submitted by market participants. In the long-term time frame, the uncertainty for forecasting GDSK is particularly high, so very conservative assumptions need to be made when aggregating nodes into zones and representing the inter-zonal relationship. Furthermore, transmission rights and forward energy contracts exhibit weaker hedging function in the zonal market compared with the nodal market. The main reason is different level granularity of network constraints used in the optimization process. Nodal pricing provides a consistent nodal grid model for the market in different time frames. For instance, when the FTR price is fixed in the auctions prior to spot market, the user in effect pays the nodal price at the injection node and the FTR price set in the previous auction. Under zonal model, the nodal view of grid is only implemented in the redispatch and balancing market where the TSO is the single buyer, which means buyer bids are not open to market participants anymore. Thus, the transmission rights and energy contracts issued from joint auctioning based on inter-zonal model prior to day-ahead market can not hedge the redispatch costs incurred after the market closure that reflects intra-zonal constraints.

- Moreover, variations of marginal generator cost are set in the case study scenarios to reflect the impact of changing carbon price. The higher the cost of the marginal generator in redispatch process, the higher the unhedged redispatch cost for the user. The integrated redispatch across borders where TSOs have full access to resources of the whole system can reduce the redispatch costs significantly. Under the decentralised governance structure where national based TSOs and power exchanges interact to clear market, redispatch cooperation that merges market and network operation is unlikely.

To sum up, the lack of effectiveness of market instruments that expand between different time frames under zonal pricing as opposed to nodal pricing is related to the inconsistency of adoption of inter or intra zonal network constraints in different markets. Moving towards nodal pricing and integrated market and network operation will be the prerequisite to the successful development of long-term electricity market across borders that provides effective hedging products for market players.

This research does not include strategic bidding behaviours or cover detailed auction design options when comparing the nodal and zonal market. A simplified zonal market that mainly investigates uncertainties from GDSK are constructed. There are other factors that can influence zonal model uncertainties. Future research should be expanded in these areas.

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Appendix

Decomposition of the total payment

In the in long-term auction, the payment from right holders to system operator can be summed up as:

$$TR_L = Q_{L1} * P_{L1} + Q_{L5} * P_{L5} = Q_{L1} * (LMP_{L3} - LMP_{L1}) + Q_{L5} * LMP_{L3} \tag{1}$$

Where:

TR_L means total receipt by the SO in long-term auctioning.

Q_{Li} is the quantity rewarded to bidder i at long-term auctioning.

P_{Li} is the price received by bidder i at long-term auctioning.

LMP_{Lj} is the locational marginal pricing at node j at long-term auctioning.

In the day-ahead auctioning, payment from right holders to system operator can be written as:

$$TR_D = Q_{D1} * P_{D1} + Q_{D5} * P_{D5} = Q_{D1} * (LMP_{D3} - LMP_{D1}) + Q_{D5} * LMP_{D3} \tag{2}$$

Where:

TR_D means total receipt by the SO in day-ahead auctioning.

Q_{Di} is the quantity rewarded to bidder i at day-ahead auctioning.

P_{Di} is the price received by bidder i at day-ahead auctioning.

LMP_{Lj} is the locational marginal pricing at node j at day-ahead auctioning.

Total payment TP_D from SO to the bid winners from long-term auction at the day-ahead auctioning can be written as:

$$TP_D = Q_{L1} * P_{D1} + Q_{L5} * P_{D5} \tag{3}$$

In the day-ahead time frame, the net payment from the user that represent bidder 1 for FTR between node 1 and node 3 and bidder 5 for energy purchase at node 3 is:

$$TP_D - TR_D = (LMP_{D3} - LMP_{D1}) * (Q_{D1} - Q_{L1}) + LMP_{D3} * (Q_{D5} - Q_{L5}) \tag{4}$$

The net payment from the user in the day-ahead consists of two parts: additional FTR acquired by the right holder in day-ahead auction on the basis of long-tern auction quantity at the day-ahead price where the FTR node pairs locate; additional energy purchase amount for the right holders at the day-ahead price where the load locates.

Suppose the sum of energy purchase and FTR cleared at long-term auctioning is Q_L. The sum of energy purchase and FTR cleared at day-ahead auctioning is Q_D. The difference of the sum of cleared FTR and energy purchase between day-ahead and long-term auctioning is denoted as Q_{DL}. The load at real time is Q_R. The difference between the real time load and the sum of FTR and energy purchase in day-ahead auctioning is designated as Q_{RD}.

At real time, the load can be represented as:

$$Q_R = Q_{D1} + Q_{D5} + Q_{DR} \tag{5}$$

The SO receipt from load at real time is:

$$TR_R = LMP_{R3} * Q_R \tag{6}$$

Where:

LMP_{Ri} is the real time price at node i.

TR_R is the total load payment from user to the SO.

The total payment from SO to day-ahead bid winners can be expressed as:

$$TP_R = (LMP_{R3} - LMP_{R1}) * Q_{D1} + \ LMP_{R3} * Q_{D5} \tag{7}$$

Where:

TP_R is the total payment from the SO to the day-ahead auction winners.

The net payment from the user to the SO at real-time can be represented as:

$$TR_R - TP_R = LMP_{R1} * Q_{D1} + \ LMP_{R3} * Q_{DR} \tag{8}$$

The total payment from load across time frames can be added up:

$$TP = TR_L + \ TP_D - TR_D + TR_R - TP_R \tag{9}$$

For the amount covered by FTR, the user will first pay in the long-term auctioning at the long-term clearing price. In the day-ahead auctioning, the user will pay at the day-ahead clearing price for the additional amount of FTR awarded in comparison to the long-term auctioning award. The amount of energy purchase related to the amount of FTR awarded in the day-ahead market is multiplied by the energy price at the injection node at the real time price.

For the energy purchase contract, the user will first pay in the long-term auctioning at the locational marginal price at the load node. In the day-ahead auctioning, the user will pay for the additional amount of energy purchase contract awarded in this time frame compared to long-term auctioning at day-ahead locational marginal price for load node. Finally, the difference between the clearing volume in real-time market and day-ahead auctioning, is paid the real time locational marginal price at load node.

A key finding from strategy B is that the total payment made by the user employing congestion hedging instruments in the long-term and day-ahead auctioning can be decomposed into costs in different time frames. The intertemporal relationship of the cost components can be clearly observed in equation. While the user pays the LMPs of at the load node, the FTR and energy purchase contract it bids in the previous market time frames is paid back at real-time price. This relationship creates a consistent breakdown of costs that rewards the employment of hedging instruments for market players. The effectiveness for hedging congestion risk relates to the ability of user to forecast the load, its estimation of the market condition and also network congestion in bidding round.