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Nodal pricing in the European Internal Electricity Market

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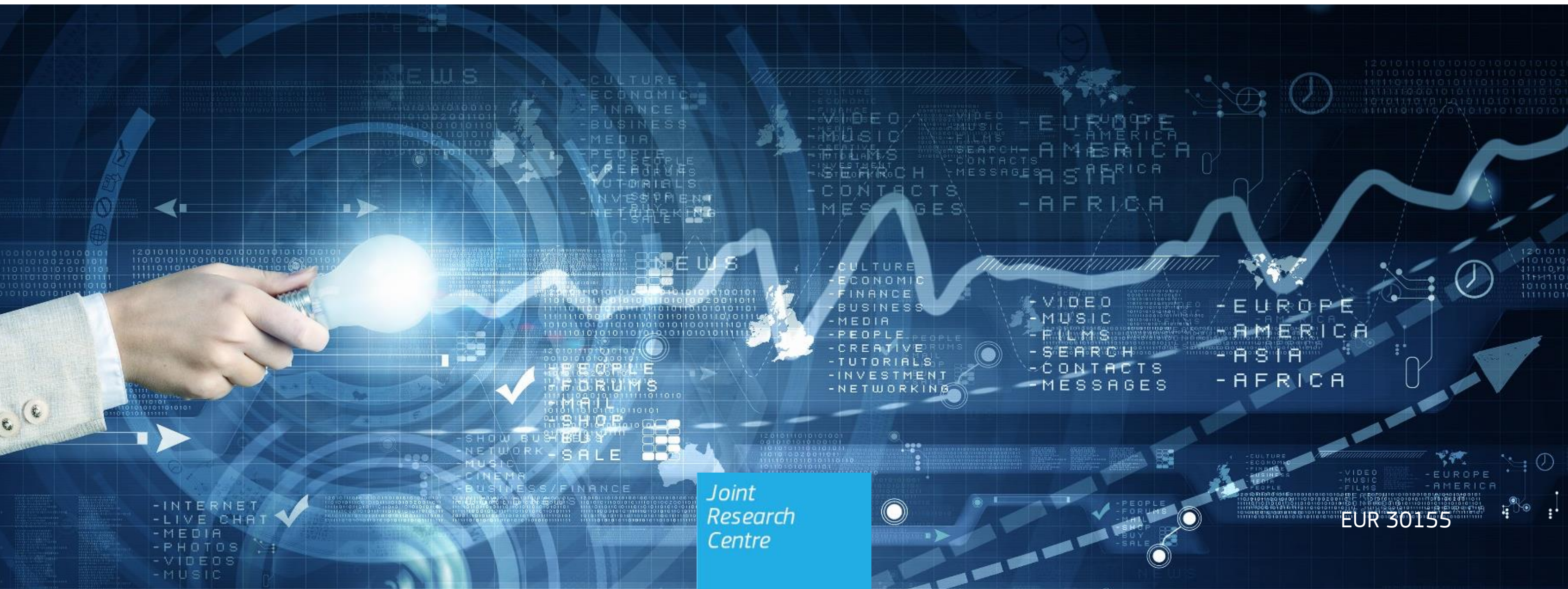

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Contents

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The authors recognise the valuable contribution by the contractors Tractebel-Engie to the successful completion of the project to analyse the possibility and the effects of implementing nodal pricing in the European Internal electricity market based on the current and proposed legal framework.

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Abstract

This report summarises the findings of a project, awarded to Tractebel-Engie, to analyse the possibility and the effects of implementing nodal pricing in the European Internal electricity market based on the current and proposed legal framework. The report presents the origins and organisation of nodal pricing and the documented costs and benefits and describes the implementation challenges of applying nodal pricing in the EU.

Executive summary

Policy context

The European electricity Internal Energy Market is based on the concept of the Bidding Zones. Zones are modelled as one node each and therefore it is assumed that there is no structural congestion internally, thus giving uniform price within each pricing area. If there are insufficient capacities in the network to transmit the contracted power, then the system operator needs to adjust the generation and consumption in order to change the physical flows in the network and to mitigate cross-zonal congestion. The zonal market approach is based on strong simplifications of the physical characteristics of the electricity grid. On the other hand, the US restructured markets have moved to nodal pricing, where every node in the electricity grid is a separate bidding zone, and all (relevant) transmission constraints are taken into account in the market clearing algorithm, also known as Locational Marginal Pricing. In this scheme, the price at each node represents the locational value of energy, which includes the cost of the energy and the cost of delivering it.

In the past there have been studies and discussions regarding the use of nodal pricing in Europe. Indeed, the move to a nodal pricing scheme was considered as one of four possibilities for improving local price signals in the EC Impact Assessment of the Clean Energy package.

Key conclusions

Within this context, the Joint Research Centre (JRC) has procured a tender in order to analyse the possibility and the effects of implementing nodal pricing in the European Internal electricity market based on the current and proposed legal framework. The contract was awarded to Tractebel-Engie. The main conclusions can be summarised below:

- Nodal pricing can be interpreted as the most extreme form of market splitting, where each node in the network represents one bidding zone. Therefore, it can be surmised that the current European market design principles theoretically do not exclude the possibility to apply nodal pricing. However, in practice transitioning from a zonal to a nodal system in the EU is cumbersome and there are several technical and regulatory challenges to overcome.
- Applying nodal pricing in the EU electricity market design would require a change in view regarding the reference market. The balancing market, being as close as possible to real-time (RT), would be the reference while DA and ID will be forward markets for that reference. Introducing nodal pricing would thus first imply a closer harmonization of the EU balancing market than is currently the case.
- The introduction of nodal pricing in European electricity markets would require the definition and allocation of new roles and responsibilities, implying rather strong institutional changes. Significant changes especially can be expected regarding the way balancing markets are conceived, becoming the true reference vs. day-ahead markets.
- Decarbonising European power markets will necessarily imply more generation at decentralised level (PV, wind, demand side management, storage). This combined with the introduction of nodal pricing raises the question on how TSOs and DSOs will interact with each other. The Clean Energy for All Europeans Package is already much more focused on aspects related to the decentralised power system. With the overall objective to enable decentralised resources to actively participate in the market, the discussion on nodal pricing could be extended to locational marginal pricing at distribution level.

Related and future JRC work

Although this study provides an analysis of the possibility and the effects of implementing nodal pricing in the European Internal electricity market based on the current and proposed legal framework, is not meant to provide an exhaustive analysis of the subject and there are several aspects that could be studied in the future. Future work could be classified according to the following categories: a) Transitioning from a zonal system to a hybrid system, b) examination of benefits of a hybrid nodal/zonal system outside the current IEM for electricity structure – "full" hybrid system and c) examination of benefits of a pan-EU nodal system.

1 Introduction

The European electricity sector is undergoing radical changes in every segment of the power industry, from generation to supply. Ambitious policy goals set at European level to enhance the competitiveness, security and sustainability of the EU's energy system have called for major changes in the regulatory, technological, and market structure fields. Europe is moving towards a fully-integrated Internal Energy Market (IEM), thus enabling the free flow of energy throughout the EU through adequate infrastructure, without technical or regulatory barriers, and providing efficient means to increase security of supply. In addition, economy decarbonisation is achieved, through enforcing European and national targets in terms of greenhouse gases emissions and making EU the world leader in renewables. These policies of the European Union (EU), and the initiatives towards a low-carbon electricity production, have profound effects on the manner in which the energy sector is and will be organised in the future. Building new infrastructure when and where is needed is important, along with providing the right economic signals through proper market designs. In addition, recently the new legislative package "Clean Energy For All Europeans'' has been adopted, designed with the aim of further completing the internal market for electricity and implementing the Energy Union.

The European electricity Internal Energy Market is based on the concept of the Bidding Zones. Zones are modelled as one node each and therefore it is assumed that there is no structural congestion internally, thus giving uniform price within each pricing area. If there are insufficient capacities in the network to transmit the contracted power, then the system operator needs to adjust the generation and consumption in order to change the physical flows in the network and to mitigate cross-zonal congestion. The zonal market approach is based on strong simplifications of the physical characteristics of the electricity grid. On the other hand, the US restructured markets have moved to nodal pricing, where every node in the electricity grid is a separate bidding zone, and all (relevant) transmission constraints are taken into account in the market clearing algorithm, also known as Locational Marginal Pricing. In this scheme, the price at each node represents the locational value of energy, which includes the cost of the energy and the cost of delivering it (Phillips, 2004).

In the past there have been studies and discussions regarding the use of nodal pricing in Europe. Indeed, the move to a nodal pricing scheme was considered as one of four possibilities for improving local price signals in the EC Impact Assessment of the Clean Energy package (European Commision, 2016). In addition, according to (European Commision, 2016) and other studies "*Theoretically, nodal pricing is the most optimal pricing system for electricity markets and networks*.". In addition, Supponen (Supponen, 2011) notes that the system of zonal pricing will not use the transmission system as efficiently as a system with a finer geographical resolution such as nodal pricing. Furthermore, it is pointed out in (Supponen, 2011) that nodal pricing should be kept on the agenda, in particular as transmission constraints seem to become worse in the future due to integration of wind power, that will cause more price volatility and congestion in the transmission network, and due to increased difficulties to build new transmission assets.

Within this context, the Joint Research Centre (JRC) has procured a tender in order to qualitatively analyse the possibility and the effects of implementing nodal pricing in the European Internal electricity market based on the current and proposed legal framework. The contract was awarded to Tractebel-Engie. This report summarises the findings of the project (Tractebel - Engie, 2019).

The structure of the report is as follows. Chapter 2 presents an overview of the current legal and regulatory framework with regard to the European internal electricity market. Chapter 3 presents the origins and organisation of nodal pricing and it's documented costs and benefits. Chapter 4 describes the implementation challenges of applying nodal pricing in the EU. Finally, Chapter 5 summarises the main conclusions and further work.

2 European Internal Electricity Market target model according to the Clean Energy Package and Capacity Allocation and Congestion Management Framework Guidelines

The Third Energy Package that was adopted in 2009, aimed at further liberalising and integrating Europe's energy markets. The Package pursued the general objective of completing the European Union Internal Energy Market (IEM) and contained provisions on a number of aspects related to electricity and gas supplies, in particular in the following areas:

- unbundling energy suppliers from network operators;
- strengthening the independence of regulators;
- establishing the Agency for the Cooperation of Energy Regulators (ACER);
- enhancing cross-border cooperation between transmission system operators and the creation of European Networks for Transmission System Operators (ENTSO-E and ENTSO-G);
- open, fair retail markets and consumer protection,
- contract switching,
- contract termination fees,
- billing of electricity and gas consumption,
- the right to receive information on energy consumption,
- quick and cheap disputes resolution.

Specifically, regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity, sets out the areas in which network codes will be developed and a process for developing them. These codes are a detailed set of rules pushing for the harmonisation of previously more nationally oriented electricity markets and regulations. In 2017, after a long process by ENTSO-E, ACER, the EC and many involved stakeholders from across the electricity sector, eight network codes and guidelines have been developed and entered into force. After the development of the network codes, the implementation phase started.

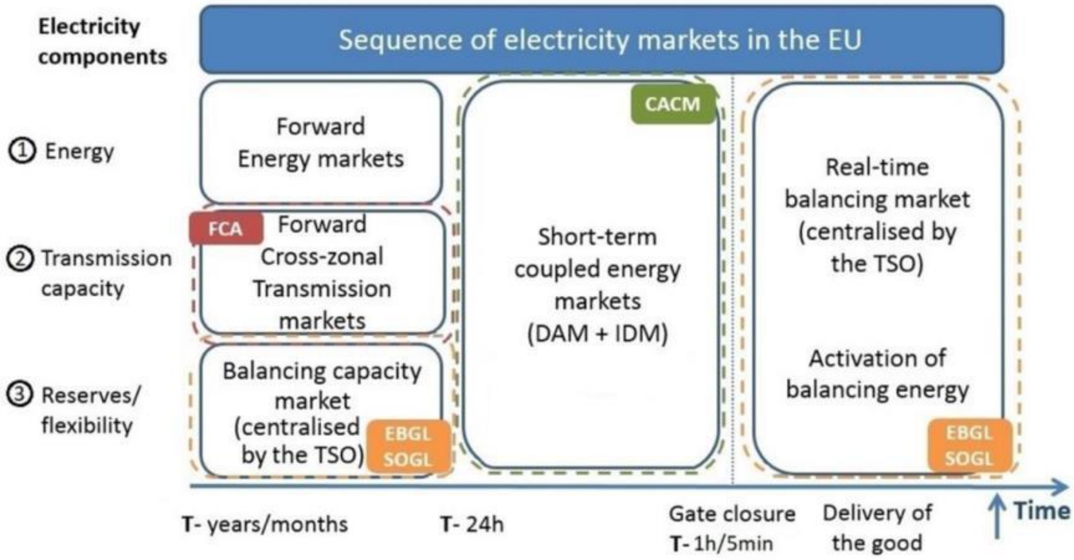
These eight Regulations can be subdivided into three groups (Florence School of Regulation Technical report, 2019):

- The market codes:
  - The capacity allocation and congestion management guideline (CACM GL) – published on 25 July 2015
  - The forward capacity allocation guidelines (FCA GL) – published on 27 September 2016
  - The electricity balancing guideline (EB GL) – published on 23 November 2017
- The connection codes:
  - The network code on requirements for grid connection of generators (RfG NC) – published on 14 April 2016
  - The demand connection network code (DC NC) – published on 18 August 2016
  - The requirements for grid connection of high voltage direct current systems and direct current-connected power park modules network code (HVDC NC) – published on 8 September 2016
- The operation codes:
  - The electricity transmission system operation guideline (SO GL) – published on 25 August 2017
  - The electricity emergency and restoration network code (ER NC) – published on 24 November 2017

The most relevant network codes when talking about electricity markets are the market codes (CACM GL, FCA GL and EB GL) and also the SO GL, as electricity markets are coupled to the system operation. These network codes describe the market design for the European internal electricity market, commonly called "target model", which is based on a temporal sequence of forward, short term day-ahead (DAM), intraday (IDM) as well as real-time balancing markets (BM).

The electricity grid is represented by zones and cross-zonal trade is feasible according to transmission capacities, defined following the Net Transfer Capacity (NTC) or the flow-based approach. The latter is the rule in DAM and if the grid is highly meshed. In IDM, the rule is NTC since trading is continuous bilateral. This "simplification" requires countertrading and out-of-market re-dispatch measures to align with the physical characteristics of the grid. The view is that the DAM is the reference, while IDM and Balancing are adjustment markets. Figure 1 shows the sequence of electricity markets in the EU.

Figure 1: The European target model for electricity markets



Source: (Florence School of Regulation Technical report, 2019), 2019.

The European Commission proposed in November 2016 its Clean Energy Package (CEP), which was approved in late 2018 and 2019.

The Clean Energy Package comprises of the following legal documents:

- Energy Performance of Buildings Directive 2018/844
- The recast Renewable Energy Directive (EU) 2018/2001
- The revised Energy Efficiency Directive (EU) 2018/2002
- Governance of the energy union and climate action (EU) Regulation 2018/1999
- Regulation on risk-preparedness in the electricity sector (EU) 2019/941
- Regulation establishing a European Union Agency for the Cooperation of Energy Regulators (EU) 2019/942
- Regulation on the internal market for electricity (EU) 2019/943
- Directive on common rules for the internal market for electricity (EU) 2019/944

In its Clean Energy Package (CEP) the European Commission proposed a recast of Regulation (EC) 714/2009. This recast includes provisions that modify the operation of a number of the network codes and guidelines, and in some cases quite significantly. For example, CEP provisions alter the amendment process for existing network codes/guidelines, and the drafting process for newly introduced network codes. Also, additional areas for a ''second generation of network codes and guidelines'' were identified. Examples are rules on demand response, including aggregation, energy storage, and demand curtailment and rules for the non-discriminatory, transparent provision of non-frequency ancillary services (Florence School of Regulation Technical report, 2019).

3 Origins and organisation of nodal pricing, its costs and benefits (Literature review)

In the last few decades, the electricity grids of European countries have become more and more interconnected. Nowadays continental Europe is a single synchronously operated electricity grid. On top of the operation of the interconnected grid, the European internal electricity market aims at the development of a single electricity market for trading, for the benefit of the consumer. As mentioned before, the current European electricity market is following a market design that is referred to as a zonal pricing electricity market.

An alternative to the established zonal pricing market in Europe is the nodal marginal pricing electricity market, which is being used in various regions of the US and also in New Zealand. This chapter deals with the origins of nodal pricing and what constitutes the backbone of the nodal design, based on the available literature. In addition, this chapter discusses the costs and benefits of nodal pricing, as documented in the US according to the experience gained through the transition to nodal and in Europe based on available studies.

3.1 Origins of nodal pricing

In the former regulated electricity system, the short-term power system was run by a centralized and regulated entity. The inflexible units were scheduled a day in advance based on optimization techniques that selected the combination of power plants to serve the load in a cost effective manner. In real time, the operation of the units and the transmission network were supported by Optimal Power Flow (OPF) optimization techniques. A basic challenge posed by competition in the power sector was to find a market organization, and in particular a non-discriminatory price system which induces market participants to behave in an efficient way.

Short-term wholesale electricity markets differ from markets for other products due to the fact that the electricity produced by a generation unit at one location is not delivered to a customer at another location in the same sense as, for example, a car is produced at the factory and is delivered to the customer that purchased it in another location. Energy injected into the transmission network flows according to physical laws, rather than directly from the seller to the buyer. The capacity of the transmission network often limits the amount of energy generation units at certain locations can inject and the amount that consumers at certain locations can withdraw. This circumstance is referred to as transmission congestion (Wolak, 2011).

The work of Schweppe et al. (Schweppe, et al., 1988) developed the theory of spot pricing that respected the particular physical conditions of electric power transmission systems and provided the basis for the nodal pricing by transposing basic micro economic principles to the optimization technology used in the power system. Prices should be (short-term) spot prices derived from generators bids through a (possibly complex) auction that mimics the OPF.

In essence, nodal pricing (or Locational Marginal Price - LMP, Location-Based Marginal Pricing - LBMP and Competitive Locational Prices – CLP) is a method of determining prices in which market clearing prices are calculated for a number of locations on the transmission grid called nodes. Each node represents a physical location on the transmission system including generators and loads. The price at each node reflects the locational value of energy, which includes the cost of the energy and the cost of delivering it (i.e. losses and congestion). Nodal prices are determined by calculating the incremental cost of serving one additional MW of load at each respective location subject to system constraints (e.g. transmission limits, maximal generation capacity). Differences of prices between nodes reflect the costs of transmission (Dietrich, et al., 2005).

All markets in the US began with zonal congestion management (in part due to computational issues) with physical transmission rights (PTRs). In 1997 the use of a pricing system, representative of a zonal approach, proposed by PECO (Philadelphia Electric Company, now an Exelon company) showed the limits of this approach (Hogan, 1999). Faced with this reality, the Federal Energy Regulatory Commission (FERC) in the US acted to approve the locational pricing system that became operational in Pennsylvania-New Jersey-Maryland (PJM) regional transmission organization at the beginning of April of 1998 and the progressive adoption of it by the voluntary pools of the East Coast of the United States. The success of PJM has led FERC to make nodal pricing part of its standard market design proposal. Eventually, all restructured electricity markets in the US moved to nodal congestion management. In addition, New Zealand introduced a first version of nodal pricing in 1997. Some of the reasons for the move in these US electricity markets were (Sioshansi, 2017):

- Near-constant need for real-time remedial actions (re-dispatch and counter-trading) with the zonal system.

- "Increase-decrease" game, which has been at the origin of the failure of the zonal market in PECO in 1997 that the nodal system eliminates.
- Hidden congestion costs and cost socialization.
- Cross-subsidies.
- Difficulty to 'predict' inter-zonal congestion.
- Difficulty and lengthy process to define new zones, for example changing the zones in California took years to get approval.

PECO's lesson was that spot prices must be spatial and, in particular, nodal. One must give plants the right incentive to operate taking transmission constraints into account: prices have to embed a local signal that reflects network constraints.

3.2 Organisation of nodal pricing

The nodal and zonal systems differ by both the formation of energy and transmission prices in Real Time (RT) and by the forward/spot relation of the markets. In the US nodal system there is an explicit assumption that the Real Time market is the spot market and all other markets, including the Day-Ahead (DA) market are forward markets. In contrast, in the European zonal model the DA market is seen as the spot market, and balancing is essentially the deviations and services market.

In a basic nodal system a market finds spot prices that reflect the scarcity of the resources (energy and infrastructure) when they effectively constrain the market. Working at the nodal level makes this market spatially arbitrage free with energy prices internalizing all these constraints. The outcome of the market is thus in theory efficient. In addition, as the US development shows, DA and RT markets can also be easily expanded to include, in addition to energy, reserves of different flexibilities. The market then simultaneously clears energy and reserves, pricing them in a consistent way. This is best known as "co-optimization" and is becoming of key importance with the penetration of renewable.

In addition, the physical realities of the electricity system require coordinating the RT with longer term decisions that involve the start-up and shut down of less flexible generation. The practicality of the competitive system also requires transforming the RT prices into signals that are both efficient and more amenable to commercial transactions. The introduction of a two settlement (DA/RT) based on a succession of Unit Commitment (UC) and Optimal Power Flow (OPF) model and the transformation of those two settlements into a sequence of forward and spot markets achieves this dual objective.

Furthermore, Kirchoff's laws complicate the computation of marginal cost in any meshed grid. In fact, transmission constraints and Kirchoff's laws constitute one of the peculiarities of applying marginal cost to electricity, with non-storability being the other peculiarity. Although it is true, for both nodal and zonal architectures, that system and resource constraints must be satisfied in order to have security and quality of supply, the way that this requirement is achieved is slightly different between the two architectures.

Hogan (Hogan, 1992) states that the transmission prices calculated according to optimal spot pricing theory incorporate the marginal cost of generation, the marginal cost of losses, and the opportunity cost created by congestion in the system. Regarding the first cost group, economic dispatch calls for the use of the cheapest combination of power plants needed to meet the existing load. If all the plants and loads were located at the same place, then the plants would be dispatched in order of lowest to highest marginal cost. For the second cost group, if plants are located in different places, and power must travel over the transmission grid, then the losses of power in transmission should enter the economic dispatch calculation. But again, after adjusting for losses, economic dispatch calls for using the cheapest plants first, and optimal spot prices will be equal to marginal costs.

Regarding the third cost group, Hogan (Hogan, 1992) discusses the problem by explaining that the transmission capacities between two zones in a meshed system changes with the generation pattern. When the transmission system is constrained, congestion will prevent full use of all the cheapest plants. In this case "out-of-merit" dispatch is needed and the constrained use of the plants creates a frequently significant opportunity cost that can be assigned to the constraints which induce the congestion. Hogan argues that this opportunity cost should be included in the prices.

Thus, the transmission capacity depends on the demand because it depends on the generation pattern to satisfy the demand. Calculating a transmission capacity in a highly meshed system without knowing at the same time the generation pattern is thus a circular argument. Loop flows therefore make it very difficult or sometimes impossible to find transmission capacities that are independent of the supply pattern. This issue is addressed in the nodal system, as mentioned before, by solving simultaneously the energy requirements with the grid infrastructure.

As discussed in (Hogan, 1992), congestion constraints can arise due to two principal forms. The first is the limit on the flow of power on an individual line, due to the thermal capacity of the transmission line. Due to Kirchoff's laws, a line constraint affects every other flow in a meshed network. Therefore, a change in generation or load at any bus will have some effect on the flow on the constrained line. A second major source of congestion in a power network arises from voltage magnitude constraints at buses. Voltage constraints define operating bounds which can limit the amount of power flowing on transmission lines below their thermal limits. Hogan argues that these constraints must be included in the calculation of congestion costs, as it is not enough to account for the congestion limits created by thermal limitations on transmission lines alone. However, the prevalent way currently used to apply the nodal price approach for electricity pricing is by using the Direct Current Optimal Power Flow (DC-OPF) model. The DC-OPF focuses on real power flows and neglects voltage restrictions. In contrast the Alternating Current Optimal Power Flow (AC-OPF) model captures both constraints. The main three advantages of the DC-OPF compared to an AC model are (Dietrich, et al., 2005):

- The problem becomes smaller (about half the size).
- The solution is non-iterative.
- The network topology does not depend on the power flowing and has to be factored once only.

The use of AC-OPF for nodal pricing is an active research area.

Hogan (Hogan, 1992) notes that nodal and zonal transmission prices can sometimes be identical: a zonal system can be viewed as nodal provided: (i) zones can be considered as nodes where all plants in the zone are aggregated into a virtual plant for which one can define a marginal cost and (ii) the whole grid (lines internal to the zone and interconnections between the zones) boils down to a set of interconnections between zones with thermal and electric characteristics of the same type as those of lines. It is then possible to define zonal marginal plants and zone-to-zone transmission prices as differences of zonal prices. However, these conditions are seldom met in a highly meshed system. This does not imply that a zonal representation may not be a reasonable approximation of a nodal system, but it is an empirical question that needs to be verified in each individual case.

Furthermore, an electricity market system based on continuously varying price signals may be efficient in the short-term but not appropriate for long-term commercial transactions, where price stability is also necessary. Therefore, a spatial extension of the single zone contract to a nodal system was needed to enable a market participant to procure a certain quantity/power of electricity at a fixed price in some location "A" and resell it at a fixed price in another location B.

Nodal contracts do not suffice for that objective in a system where transmission prices are also variable. A new instrument was required to enable an agent with a fixed price contract in A to deliver to another location B, also at a fixed price. The problem was commonly solved by the so-called "contract path" that consisted in reserving some physical capacity on the grid to conduct the trade. However, Hogan (Hogan, 1992) argued that contract paths (or Physical Transmission Rights) do not correspond to any sustainable physical reality, making this approach practically unworkable. Other contracts were deemed necessary, which led to the notion of Financial Transmission Rights (FTRs), which were developed in the US in the nodal system. These enable traders from node A to node B that acquire these contracts to have their transmission congestion costs (price difference) from A to B reimbursed by the Independent System Operator (ISO).

A similar hedging problem arises with the zonal system. The Nordic system offers an alternative to US type FTRs: it operates with purely decentralized financial markets based on commercial participants. This is different from FTRs but is not the preferred option in the EU. Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation (FCA) has chosen to implement an adaptation of the US FTRs to the non-Nordic zonal market.

Table 1: Summary of nodal and zonal organisational differences

	Nodal Pricing	Zonal Pricing
Network representation	Based on the physical characteristics of the system No need to search for adequate zonal decomposition	Based on an aggregated representation of the physical reality in terms of critical infrastructures into zones. Zones shall be based on long-term structural congestions in the transmission network. There is a process in place to review and if necessary change the zones (Bidding Zones Review).
Market organisation	Two-settlement system in Day Ahead (DA) and Real Time (RT) Day Ahead and Real Time are both markets: there is an explicit assumption that RT is a spot market and DA should be a forward market. Some special product (virtual trading) has been constructed to achieve that result Market clearing based on Security Constrained Optimal Power Flow commercial software (or enhancement thereof) in Day Ahead and Real Time.	Multi-settlement systems: Day Ahead (DA) and Intraday (ID) Markets. Balancing RT is seen as a technical service and imbalances market. The combination of DA and ID is seen as the spot market. There is no DA/RT forward/spot relation (difficult to obtain as DA and RT are based on different product granularities). Market clearing in DA based on special dedicated software. ID still influx (continuous vs. discrete)
Re-dispatching and countertrading	Due to the network representation in DA or RT markets, there is no need to re-dispatch in any of these markets.	Re-dispatching and countertrading is needed in case of internal congestion.
Joint clearing with service	Allocates jointly clearing of energy and reserves	Not clear yet how to combine the clearing of energy and reserves.
Forward trading and liquidity	Forward financial energy market develops on the basis of hubs depending on liquidity. Financial transmission rights develop with TSO playing a central role. Unsolved difficulties remain.	Forward financial energy markets develop on the basis of zones depending on liquidity. Physical and Financial transmission rights develop with TSO playing a central role. Unsolved difficulties remain.

Source: (Tractebel - Engie, 2019).

Hence, spot energy and transmission prices on the one hand, financial forward contracts for hedging randomly changing prices and financial transmission rights on the other hand are the two pillars of nodal pricing.

It is also worth mentioning that although nodal pricing schemes are associated with central dispatch, they also allow self-scheduling of resources. A generator has the option of simply telling the system operator how a resource will run, rather than expressing the unit's economics and letting the schedule follow from the system operator's optimization. Self-scheduling still involves optimization, but the optimization is done by the generator, not the system operator. The generator becomes a price-taker and is only asked to deviate from the self-schedule in extreme circumstances (Cramton, 2017).

Finally, Table 1 summarises the organisational differences between nodal and zonal pricing schemes.

3.3 Costs and benefits of nodal pricing

While the theoretical benefits of nodal pricing are well understood, transition from a zonal to a nodal system is cumbersome and requires institutional changes. For markets, such as in the US, that underwent such a transition, ample experience exists on the incurred transition costs as well as the achieved benefits. However, for Europe transition cost estimates do not exist, but model based estimates on cost savings and benefits are available from the academic literature. In addition, re-dispatch costs that are inherent to the current zonal system are reported by ACER.

The effects of shifting to the nodal model can be distinguished between the short-term and the long-term consequences on efficiency.

Nodal pricing, by definition, directly impacts the **short-term efficiency**, which corresponds to a horizon of around 24 hours before delivery, from Day-Ahead down to balancing and remedial actions. Therefore, quantification of the expected/achieved benefits focuses on the short term time frame due to the improved dispatch of the system by taking the physical interconnection capacity into account.

It differs in theory from the zonal system in that the pricing of transmission is fully embedded in the energy price, capturing all network externalities. This results in diverging nodal prices if scarcity in transmission capacity arises. In Real-Time, a similar market is organized to adjust the schedule according to forecast updates or plant availability changes.

Zonal prices, on the other hand, are based on an aggregated and simplified version of the physical network (Flow-Based or Available Transfer Capacity in the EU) and only account for inter-zonal congestion. The dispatch schedule therefore in the zonal system might correspond to infeasible trades (system-wise), which is why zonal pricing heavily relies on close-to-RT remedial actions by TSOs to ensure proper delivery and balancing.

With nodal pricing, the Day-Ahead (DA) market is cleared using a security-constrained Optimal Power Flow (OPF) model including the transmission. Hence, infeasible trades are not accepted, which results in lower overall welfare, compared to a Zonal dispatch with remedial actions considered. In addition, because the DA schedule is physical, the need for intraday market revisions is greatly reduced. In fact, in nodal US systems, such markets do not even exist.

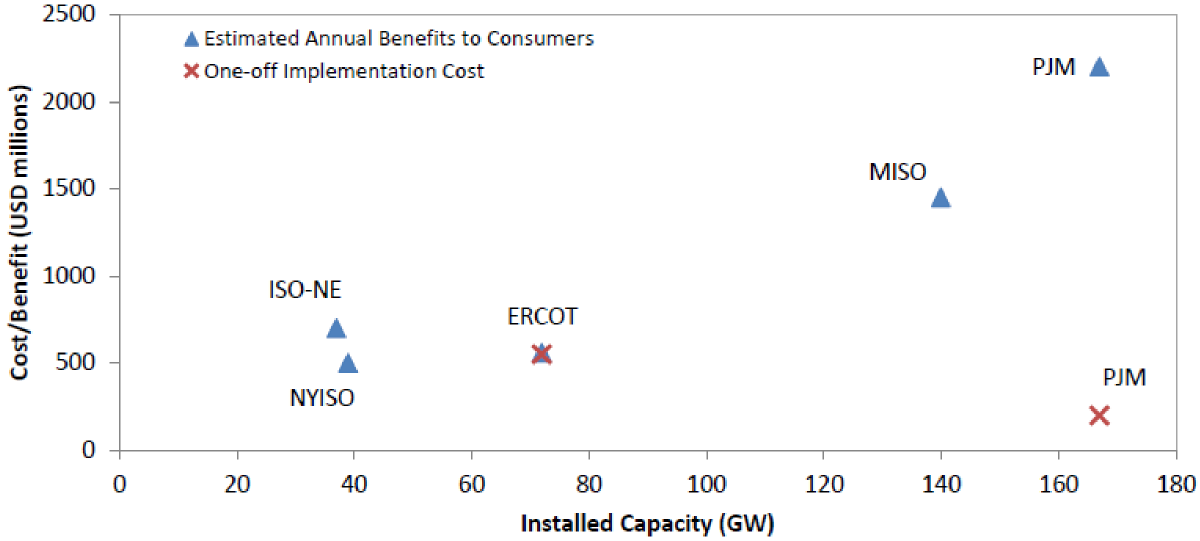
Most benefits from a nodal model arise close to Real-Time (RT). Because the final schedule is achieved through a central market with bids rather than a set of unilateral measures by the TSO, the total costs can be cut down quite considerably. What's more, RT locational prices allow for a much more optimal use of flexible units such as storage, EVs or Demand-Side Response.

It is therefore generally suggested by the theory that the overall impact of transitioning to a nodal scheme is positive. This statement can be verified in practice by reviewing the performances of US markets. Throughout the nodal implementation timeframe, several studies were released by Independent System Operators (ISO), all suggesting clear benefits from the nodal transition.

According, to Neuhoff (Neuhoff, et al., 2011), PJM, the prime mover towards nodal pricing in the US, saw its annual benefits to consumers reach approximately 2250 M$, with a one-off implementation cost of around 200 M$. Meanwhile, ERCOT recorded 550 M$ for both its implementation costs and its annual benefits. This is shown in Figure 2.

Besides a more cost effective dispatch, location-specific information on generation, load and readjustments, in combination with the increasing regional coverage, improved PJM's understanding of current flow patterns and short-term forecasts. Over time, PJM was able to reduce operating margins to accommodate uncertainty (Neuhoff, et al., 2011).

Figure 2: Annual benefits and one-off implementation costs vs. installed capacity from the transition to nodal pricing



Source: (Neuhoff, et al., 2011), 2011.

Cost estimates for Europe come from model-based analyses by academics and industry that point towards similar behaviours, although Europe wide Cost Benefit Analysis has not yet been carried out. Neuhoff, et al. (Neuhoff, et al., 2013) suggests that some €0.8–€2.0 billion cost savings per year and an increased use of international transmission capacity of up to 34% are possible with nodal pricing. In addition, Papavasiliou (Papavasiliou, et al., 2018) reports that for the Central Western Europe countries nodal design outperforms Flow Based Market Coupling and Available Transfer Capacity Market Coupling by ~720M€/year. Furthermore, ACER (Agency for the Cooperation of Energy Regulators (ACER), 2018) calculates the cost for remedial actions for 2017 at almost 2.14 B€ for the EU, with a relative increase of 129% compared to 2016. ACER also notes that the use of remedial measures in Europe has become frequent, and is likely to become even more frequent in the near future. A specific assessment of the Polish case performed by Bjorndal (Bjorndal, et al., 2018) finds that Poland could greatly reduce its re-dispatching cost in the hybrid pricing model. Compared to the full zonal pricing scheme, the study finds that re-dispatch costs for Poland are reduced by 93% in one of the scenarios, when only Poland uses nodal pricing.

Mohrhauer (Mohrhauer, 2016) compares nodal, zonal and hybrid market structures with respect to operating cost and re-dispatch volumes. Models were developed and then applied to the IEEE 118 bus system with three newly introduced zones to simulate the three market designs. The thesis concludes that the zone which made the switch to nodal pricing always profited the most from the hybrid market situation. The study has shown that switching to nodal pricing always had a benefit for the zone performing the switch, and that the scale of this benefit was dependent on the amount of congested lines, and the marginal electricity price of the zone in the zonal pricing system.

Since these are model-based estimates, the results should be read in conjunction with the underlying, and mostly simplifying assumptions. Despite the assumptions used, these studies show expectations for improvements in the case of the EU transitioning to nodal pricing scheme. However, before being able to capture all the benefits it can provide, the transition itself must be addressed in the current operational and regulatory context. This will be touched upon in the next chapter.

It is worth mentioning that most of the above discussion on nodal prices restoring short-term efficiency assumes no market power. The existence of this property thus needs market power mitigation methods, a subject on which there has been a lot of activity and which is a common issue in both nodal and zonal systems. The "three pivotal supplier test" implemented in the US markets to control market power on an almost instantaneous basis is a well-known example of those measures (HoustonKemp Economics, 2018).

Long-term efficiency corresponds to having both efficient forward markets and adequate signals for future investment in generation and transmission (so that security of supply and low end prices can be ensured). According to Hogan, long-term efficiency naturally emerges from “getting the prices right” in the short-term. This efficiency materializes into having both effective forward markets and adequate future investments in capacity and transmission.

On the one hand, locational and unbiased price signals are needed to ensure enough investments so as to guarantee security of supply and low end prices to consumers. On the other hand, forward markets are tools utilized by market participants to trade physical and financial products with the goal to hedge their positions against long-term price uncertainties. The effectiveness of such markets is primarily measured in terms of their liquidity and the characteristics of their products. Although the nodal model does not directly impact forward trading, a change in the real time prices computation methodology will inevitably impact the hedging process. Transitional arrangements may be required to smoothly shift away from previous arrangements.

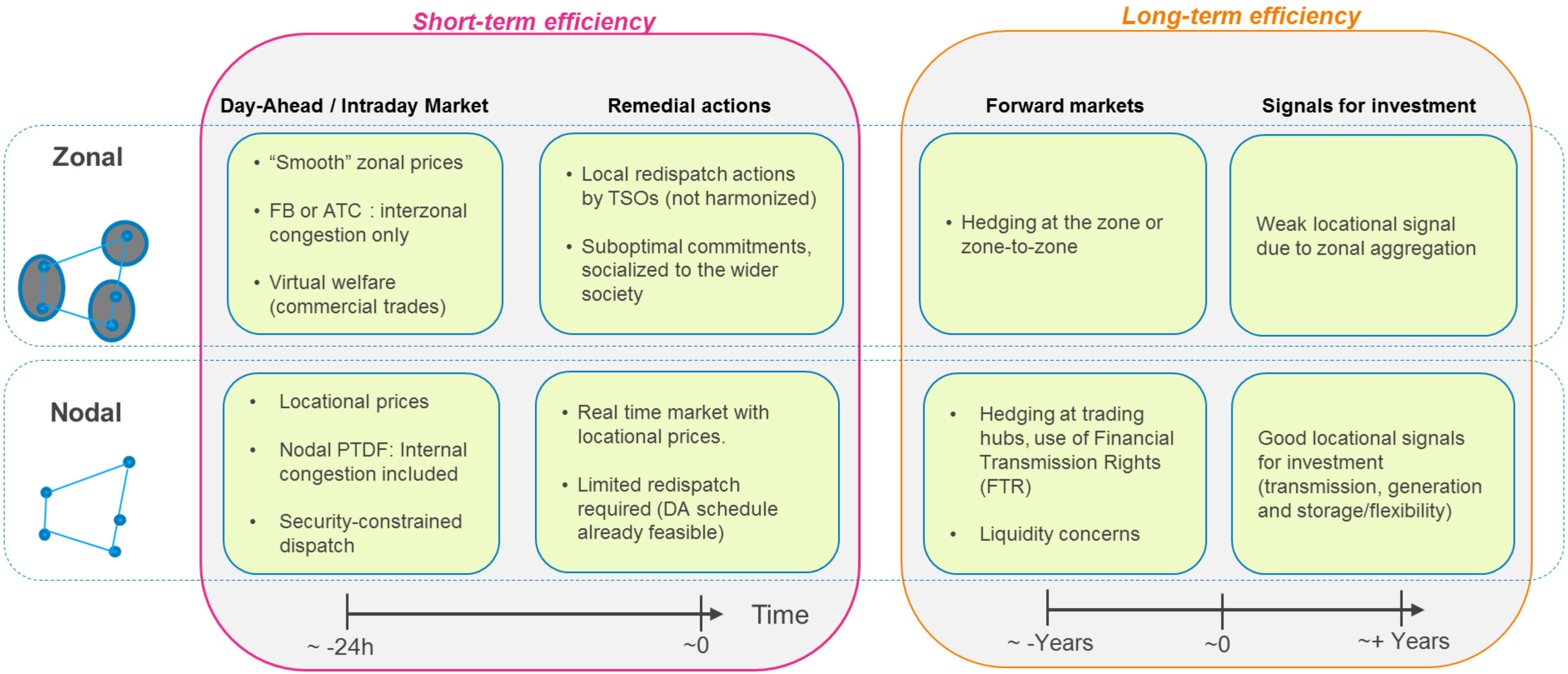
Regarding long-term investment planning efficiency, as in reality most investments are lumpy and not marginal (e.g. the use of technically standardised assets and lines will result in an over or undersized investment) and thus revenues are often not in line with the actual costs, nodal pricing alone cannot ensure investments which result in full recovery of network costs. In order to ensure full revenue adequacy, a suitable tariff design must also be implemented (Pérez-Arriaga, et al., 1996).

While nodal pricing does not directly impact forward market, concerns were raised about potential drops in market liquidity due to even lower predictability of short-term prices (stronger distributional effects) and reduced participant pool at each trading hub. While in a zonal system participants all hedge in their zone (same price, many parties), in a nodal system participants have to hedge at local trading hubs which do not exist for every node. When prices differ because of scarcity, finding a fitting hedge becomes challenging. A remedy to this peculiarity for most nodal systems was to introduce Financial Transmission Rights (FTRs). These products specifically hedge against the transmission price risk between a source and a sink node and therefore enable full hedging regardless of the network location (Lyons, et al., 2000).

Although forward markets differ substantially from one country to another (Agency for the Cooperation of Energy Regulators (ACER), 2018), which makes their overall comparison not straightforward, it appears that in the US, trading at and between the hubs is very liquid in the forward exchanges. Looking at the level of forward contracting observed among PJM market participants at the PJM Western Hub, when considering all actively traded hubs across all exchanges within the PJM network, liquidity in one year ahead power transactions exceed peak energy requirement by a factor of 4 to 5 and the three year forward is twice the annual requirement (Neuhoff, et al., 2011).

Figure 3 summarises the nodal and zonal short-term and long-term consequences on efficiency.

Figure 3: Nodal and zonal short-term and long-term implications



Source: (Tractebel - Engie, 2019).

4 Nodal pricing for the EU: implementation challenges

As mentioned before, the target model for the European internal electricity market is based on a temporal sequence of forward, short term day-ahead, intraday as well as real-time balancing markets. The rules governing these markets are laid down in eight Commission Regulations, commonly referred to as Network Codes. The electricity grid is represented by zones and cross-zonal trade is feasible according to transmission capacities, defined following the Net Transfer Capacity (NTC) or the flow-based approach. In Intra-Day (ID) Market, transmission capacities are established by the calculation of NTCs between zones since trading is continuous bilateral. This "simplification" of the grid requires countertrading and out-of-market re-dispatch measures to align with the physical characteristics of the grid, in case of internal congestion.

As mentioned before, transitioning from a zonal to a nodal system in the EU is cumbersome and there are several challenges to overcome. This section briefly describes the main market design aspects for applying the nodal pricing scheme in the European internal electricity market and their implementation challenges and raises questions regarding the institutional aspects of the transition.

4.1 Grid representation

Nodal pricing can be interpreted as the most extreme form of market splitting, where each node in the network represents one bidding zone. Therefore, it can be surmised that the current European market design principles theoretically do not exclude the possibility to apply nodal pricing.

The Commission Regulation (EU) 2015/1222 of 24 July 2015 on establishing a guideline on Capacity Allocation and Congestion Management (CACM) coordinates the transmission capacity calculation and addresses the definition of bidding zones for the day-ahead and the intraday market time frame. The CACM provides guidelines on how congestion is to be managed, in order to implement single day-ahead and intraday coupling.

In addition, Article 32 sets rules on how to review existing bidding zones, which should reflect structural congestion. If internal constraints persist, bidding zones should be reviewed. Therefore, in theory, it could be envisaged that continuous adjustments of bidding zones could in the end lead to a nodal pricing environment or close to it. However, as highlighted in the ENTSO-E bidding zone review (ENTSO-E, 2018), any change in the number of bidding zones leads to transition and transaction costs.

Therefore, given the associated costs with bidding zones adjustment and the relative long time required for the adjustment, due also to the opposition by some Member States to split their national bidding zones, it is questionable whether nodal pricing will be the end-state of a continuous adjustment of bidding zones, or whether it is more efficient, assuming the benefits and costs have been properly calculated, to move to a nodal pricing at once, at least at regional level.

Furthermore, to calculate cross-zonal capacity, TSOs have to rely on a common representation of the transmission grid. The CACM requires all TSOs to establish a Common Grid Model (CGM) representing the European interconnected system to define cross-border transmission capacities in a coordinated way. Article 17 of the CACM requires TSOs to jointly develop a CGM methodology, with at least the definition of a scenario for each market time unit (hour) of the day-ahead and intraday market time frame, forecasting the generation, the load and the grid topology. The principles of this methodology regarding, amongst others, the definition of scenarios, the building of individual grid models by each TSO and their merging into the CGM were proposed in 2016 (ENTSO-E, 2016) and approved by the national regulatory authorities in 2017 (All Regulatory Authorities, 2017). While the principles of the CGM methodology are valid for all TSOs and bidding zones, closer cooperation and coordination is realized at regional level, in the so-called Capacity Calculation Regions (CCR). CCRs consist of a set bidding zones where TSOs closely cooperate in the determination of cross-zonal transmission capacity.

A natural choice for the implementation of nodal pricing would therefore be at the level of the CCRs. Data exchanged on generation, load and especially the grid topology would be more considerable than today, but information would in principle be based on technical characteristics about the intra-zonal transmission networks, rather than on simplifications of the latter.

4.2 Balancing market as reference

As mentioned before, the current view, regarding the European target model is that the Day-Ahead (DA) is the reference market, while Intra-Day (ID) and Balancing are adjustment markets. After the intraday markets close, the national TSOs are responsible for the balance of supply and demand and guarantee operational security. This is organized by a balancing market/mechanism where, on one side, Balancing Responsible Parties (BRP) are accountable for their imbalances (i.e. difference between the allocated volume attributed to a BRP and its final position) and, on the other side, Balancing Service Providers (BSPs) with reserve-proven units providing balancing services to TSOs in order to correct for those imbalances. Furthermore, to ease network operation and guarantee security, the TSO can also include specific rules with respect to the BRP's positions, as well as extra planning requirement in the day-ahead/intraday as to cover their positions.

However, applying nodal pricing in the EU electricity market design would require a change in view regarding the reference market: the balancing market, being as close as possible to real-time (RT), would be the reference while DA and ID will be forward markets for that reference. The real-time market corresponds thus to the true electricity spot market, as this is when demand and supply effectively meet subject to instantaneous system constraints. Asset values (energy and infrastructures) can thus only be observed in RT, and all other market activities happening before (i.e. intraday, day-ahead, futures trading, etc.) are necessary to provide hedges, support the provisional planning and help in key decisions on the resources.

Introducing nodal pricing would thus first imply a closer harmonization of the EU balancing market than is currently the case. Although, according to Article 24 of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (EBGL), TSOs need to harmonise certain features of their balancing mechanism (gate closure, activation, pricing rule), the pricing rule still differs widely, ranging from competitive market price formation (where BSPs are remunerated according to pay-as-clear and imbalances are valued at this market price) to tariff and penalties for imbalances.

Once it is established that the Balancing Market should be the true reference market, there are different ways to organize such a market. Two approaches are conceivable:

- Move towards a 2-settlement system, as in the US design
- Make a market out of the Balancing Market

In a nodal system as in the US, the balancing position (deviation between DA and RT) is metered at the node level (removing the possibility to do zonal aggregation by BRPs) and is valued on nodal prices, based on a real time clearing. Hence, the first approach is to organize short-term operations as a two-settlement system, replacing the balancing market by a real-time market organized by an ISO, as in the US. This approach necessarily implies a deep restructuring of balancing markets, requiring profound modification of the EU design.

Another possibility requiring less structural changes would be to keep the balancing mechanism of the TSOs and modify them by, firstly, moving towards competitive nodal market (i.e. where nodal price arise from a joint clearing of energy bids from BSPs, together with the transmission capacities) and, secondly, revising/relaxing BRPs extra requirement accounting for the fact that a nodal system can accommodate larger imbalances in real time as it explicitly models limited transmission capacities. For the second approach, the degree of harmonization is open for debate, but nodal pricing would necessarily require an alignment of the products, their procurement and pricing, and the imbalance settlement period. Also, the role of a balancing responsible party covering several nodes would need to be revisited. In addition, institutionally there is the question whether such a market can still be organised by the TSOs, as there might be a potential conflict of interest regarding the value of transmission.

4.3 Role of Day-Ahead market in the nodal system

In the US style nodal pricing scheme, the Day-Ahead market is both a financial and a physical market. While still being a forward market for real-time activities, it also corresponds to a milestone where key decisions on resources commitments need to be taken (as some generators are not fully flexible and their production needs accordingly to be planned in advance). To ensure an efficient provisional planning in day-ahead, there needs to be no structural deviations between the economic incentives in day-ahead and real-time, i.e. there is convergence of prices between day-ahead and real-time (or in other words, the day-ahead price should be a forward of the real-time price). Regulators in the US recognize this price convergence as a sign of efficient day-ahead/real time market operations, and continuously monitor these statistics in their state of the market report.

On the market design, there exist several ways to promote this price convergence:

- Allow opportunity cost bidding in the day-ahead market. For efficient operations, generating resources should bid their opportunity cost in the day-ahead market, i.e. anticipating their value in real-time. This value is a function of the expected prices distribution in real time and on the flexibility of the resource to adapt to this price signal.
- Introduce virtual trades. Allow market participant to choose the amount of energy contracted in day-ahead vs. real-time and arbitrage between the two markets.
- Align the market organization / pricing mechanism as much as possible between day-ahead and real time.

The European internal electricity market design mainly recognizes the first option to arbitrage the different markets.

In addition, today's EU systems are mainly based on self-scheduling of power resource. As mentioned before, in US nodal systems, there is the possibility to have a pool-scheduled resource, i.e. resource for which a participant submitted supply offers to sell electric energy and that the ISO scheduled for dispatch. However this does not prevent the market participant to do self-scheduling, by submitting to the system operators must-run bids (nomination) or simple energy bids that internalize the start-up and commitment cost.

Additional question regarding the day-ahead organisation is whether strict linear pricing is compatible with nodal pricing and whether there is the possibility to co-optimise energy and reserves.

4.4 Conditions for efficient price signals

In principle a nodal grid representation provides efficient price signals, since network externalities are fully internalized in the market algorithm. However, as mentioned before, there are at least two additional market design requirements to have an efficient price signal for market participants: they need tools to financially hedge against price risks associated to their location, and there is a need for strong ex-ante market power mitigation measures. These two requirements are discussed in the EU context.

In order for market participants to stabilize their market revenues and to hedge against price risks associated to their location in the grid, Financial Transmission Rights (FTR) have been introduced as a tool that enables such hedging.

The Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation (FCA) recognizes the need to hedge cross-zonal transmission risk. Next to the allocation of Physical Transmission rights (PTRs), it foresees FTRs applicable to the day-ahead and intraday markets, as stated in Article 31(1): "*Long-term cross-zonal capacity shall be allocated to market participants by the allocation platform in the form of physical transmission rights pursuant to the UIOSI [use-it-or-sell-it] principle or in the form of FTRs — options or FTRs — obligations*."

As provided in CACM and discussed by ENTSO-E (ENTSO-E, 2018), price signals should not only be "accurate", i.e. reflect market and grid conditions, but should also be "robust". Robustness refers to stable prices, as stated in (ENTSO-E, 2018), p.71: "robustness/stability of prices has a major impact on the predictability of future prices and also their variability, and is therefore a main factor considered by investors in their future investment decisions.".

FTRs are tools to hedge transmission risks and to incentivize efficient long term decisions. On the other hand, FTRs can also be used to facilitate the convergence from a zonal to a nodal regime. The implementation of nodal prices will necessarily lead to winners and losers. In particular, consumers in high-price nodes and producers in low-price nodes will have to be compensated. Such risks need to be compensated with, for instance, financial transmissions rights. It is worth mentioning that transitional arrangements are welfare-neutral, meaning they affect equity distribution among incumbents but do not impair the overall achievable welfare benefits of moving to the nodal pricing scheme.

As mentioned before, another common issue in both nodal and zonal systems is market monitoring and the exercise of market power. Today, market power mitigation in European power markets is organized rather expost. Moving to a nodal pricing scheme would require a stronger ex-ante control, since bids at nodal level might be subject to market power abuse more than at zonal level.

In today's US nodal markets, the responsibility to check if offers are in line with costs is assigned to ISOs. In these markets, ISOs assess automatically the nature of offers by implementing tests, following different approaches:

- Structural : PJM and California ISO (CAISO) use the Three Pivotal Supplier Test any time the market solution indicates that out of merit resources are needed to relieve a given transmission constraint. Resources that fail the test are mitigated to a price that its equal to the marginal cost estimate (MC) + 10% of MC;
- Conduct and Impact : ISO New England (ISO-NE), Midcontinent ISO (MISO) and New York ISO (NYISO) apply a two steps threshold test which firstly establishes if an offer exceeds its reference level and then they assess the impact of this offer on the price. The offers are mitigated to the MC.

4.5 Institutional aspects

The introduction of nodal pricing in European electricity markets would require the definition and allocation of new roles and responsibilities, implying rather strong institutional changes. As noted before, significant changes especially can be expected regarding the way balancing markets are conceived, becoming the true reference. Market and system operation interact closely and both are highly influenced by national preferences (e.g. pro-active vs. reactive intervention of TSOs close to real time). To study these changes and their implications requires further analysis which would go beyond the scope of the present work. However, a list of major aspects to be considered more thoroughly is provided below.

- As mentioned before, one approach for the EU to transition to the nodal pricing scheme would probably be to implement the scheme region by region. This raises the question about the feasibility of coexistence of zonal and nodal approaches and the required legal framework changes.
- The introduction of FTRs to allow market participants to hedge against price risk requires the appointment of an institution which is responsible for the organization of such a market. Also, some mechanism is needed to grandfather FTRs to existing generation units. The FCA network code allows for FTRs, to be issued by TSOs. In a nodal system, the question is raised whether it should still be the individual TSOs, or a central institution.
- Due to the need for stronger ex-ante control for market monitoring in a nodal pricing scheme, the institution that will be responsible for performing ex-ante market monitoring (controlling bids) needs to be defined.
- More generally, the role of TSOs, Nominated Electricity Market Operators (NEMOs) and Regional Coordination Centres (RCCs) will need to be revisited. In the US nodal system Independent System Operators (ISOs) are responsible for combining the operation of short term markets and network operation. The entity that takes over this role in a potential EU transition to nodal pricing will need to be defined.
- Decarbonising European power markets will necessarily imply more generation at decentralised level (PV, wind, demand side management, storage). This combined with the introduction of nodal pricing raises the question on how TSOs and DSOs will interact with each other. The Clean Energy for All Europeans Package is already much more focused on aspects related to the decentralised power system. With the overall objective to enable decentralised resources to actively participate in the market, the discussion on nodal pricing could be extended to locational marginal pricing at distribution level.

5 Conclusions and further work

This report summarised the main findings of the project to qualitatively analyse the possibility and the effects of implementing nodal pricing in the European Internal electricity market based on the current and proposed legal framework. Based on the well-documented literature, the analysis reveals that nodal pricing offers considerable clarity and simplification compared to the zonal model. Various implementations exist and remaining questions in the nodal system deal with new issues created by renewable that go much beyond the congestion management problems still discussed on the zonal model in Europe. The main conclusions can be summarised below:

- In terms of theoretical principles, the nodal system comes out first because it corresponds to a standard economic paradigm and also practice has shown that the central coordination of energy and services provided by the ISO minimizes the transaction costs of implementing this paradigm.
- It is generally suggested by the theory and in practice by reviewing the performances of US markets that the overall impact of transitioning to a nodal scheme is positive. However, regarding the EU move to nodal pricing, Europe wide Cost Benefit Analysis has not yet been carried out.
- Experience regarding the redesign of zones, in the US and Europe, suggests difficulty and lengthy process to define new zones.
- Nodal pricing can be interpreted as the most extreme form of market splitting, where each node in the network represents one bidding zone. Therefore, it can be surmised that the current European market design principles theoretically do not exclude the possibility to apply nodal pricing. However, in practice transitioning from a zonal to a nodal system in the EU is cumbersome and there are several challenges to overcome.
- Applying nodal pricing in the EU electricity market design would require a change in view regarding the reference market. The balancing market, being as close as possible to real-time (RT), would be the reference while DA and ID will be forward markets for that reference. Introducing nodal pricing would thus first imply a closer harmonization of the EU balancing market than is currently the case.
- The introduction of nodal pricing in European electricity markets would require the definition and allocation of new roles and responsibilities, implying rather strong institutional changes. Significant changes especially can be expected regarding the way balancing markets are conceived, becoming the true reference.
- Decarbonising European power markets will necessarily imply more generation at decentralised level (PV, wind, demand side management, storage). This combined with the introduction of nodal pricing raises the question on how TSOs and DSOs will interact with each other. The Clean Energy for All Europeans Package is already much more focused on aspects related to the decentralised power system. With the overall objective to enable decentralised resources to actively participate in the market, the discussion on nodal pricing could be extended to locational marginal pricing at distribution level.

This study is not meant to provide an exhaustive analysis of the subject and there are several aspects that could be studied in the future. Further work can be classified according to the following categories:

1. <u>Transitioning from a zonal system to a hybrid system</u>

The purpose of this category is to study the transition from a zonal system towards a hybrid system, ie. one where some states adopt a nodal pricing scheme (at least in some market sessions such as the Balancing market), with the rest staying into the current zonal system. The interaction among the two different systems is of particular interest. The main question is the issues and solutions for a successful interface between the nodal architecture in these nodal market sessions of these MSs and the zonal architecture of the IEM in legal, regulatory and economic terms.

2. <u>Examination of benefits of a hybrid nodal/zonal system outside the current IEM for electricity structure – "full" hybrid system</u>

Under this category, the fundamental principles of the European Internal Energy Market (IEM) for electricity are considered only for Member States that follow the zonal System. For Member States that opt for a nodal system, this extends to all market segments, including the Day-Ahead Market. The purpose of the exercise is to assess the economic and operational benefits of such configuration as well as its conceptual feasibility. A particular scope of this work stream is to identify the necessary interventions in the regulatory framework for making such a "full" hybrid system operational.

3. Examination of benefits of a pan-EU nodal system

Under this possible category, the benefits of a major reform towards the creation of a pan-EU electricity market based on nodal pricing could be investigated. Specifically, the impacts of a reform to a pan-EU nodal electricity market could be studied in terms of:

- Economic efficiency in the operation of the power system (social CBA)
- Security of Supply (more robust interventions by the TSO especially in face of increasing penetrations of variable RES)
- Long-term policy goals (e.g. GHGs/CO2 emissions)

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List of abbreviations and definitions

ACER	Agency for the Cooperation of Energy Regulators
BM	Balancing Market
BRP	Balancing Responsible Parties
BSP	Balancing Service Providers
CCR	Capacity Calculation Regions
CEP	Clean Energy Package
CGM	Common Grid Model
CLP	Competitive Locational Prices
DAM	Day-Ahead Market
ENTSO-E	European Networks for Transmission System Operators for Electricity
ENTSO-G	European Networks for Transmission System Operators for Gas
FTR	Financial Transmission Right
IDM	Intra-Day Market
ISO	Independent System Operator
LBMP	Location-Based Marginal Pricing
LMP	Locational Marginal Price
NEMO	Nominated Electricity Market Operators
NTC	Net-Transfer Capacity
OPF	Optimal Power Flow
RCC	Regional Coordination Centres
RT	Real Time

List of figures

List of tables

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