



# A survey comparing centralized and decentralized electricity markets

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## ARTICLE INFO

### JEL classification:

D44

L13

L94

### Keywords:

Wholesale electricity markets

Market clearing

Centralization

Decentralization

Unit-commitment

Self-dispatch

## ABSTRACT

This paper surveys the literature relevant for comparing centralized and decentralized wholesale electricity markets. Under a centralized design, producers submit detailed cost data to the system operator the day before delivery, who then decides how much to produce for each generation unit. This differs from the decentralized design, which relies on self-commitment, and where producers send less detailed cost information to the system operator. US markets have converged on the centralized design, whereas the trend goes in the other direction in Europe. The paper discusses advantages and disadvantages of the two approaches and proposes suggestions for improvement of each design.

## 1. Introduction

The electric power system is often referred to as the largest and most complex machine ever built by humankind. Supply and demand must be kept in balance every single minute. To manage this, a system operator takes all production decisions in real-time, also in deregulated electricity markets. The question is whether the scheduling of plants should also be centralized ahead of delivery, as in the US, or decentralized, as in Europe. Wilson [1] makes a qualitative comparison of centralized and decentralized electricity markets. Our survey revisits this discussion in view of developments during the last 20 years. The share of intermittent renewables has increased, and new technologies, such as batteries and demand response, have thus become more relevant. This means that flexibility of the market design is more important now than before. Another trend in the EU and the US is that markets are growing and delivery periods are shortened. Hence, the scalability of designs has become an important issue. Moreover, recent studies quantitatively compare centralized and decentralized electricity markets. These studies consistently show that centralized designs are more efficient in the short run, at least for markets that are dominated by thermal production and where network congestion is a major issue. Market designs, as well as clearing algorithms, have developed. Based on this and recent

developments in the academic literature, we also identify how centralized and decentralized electricity markets can be improved. Results are less clear regarding long-run effects and for markets with a large fraction of renewables.

Electricity is a perishable good because there is limited storage capacity in the power system once it is produced. This means that electricity must be consumed the moment it is produced. Often the only slack is provided by the rotating mass in generators, equipment, and turbines. These machines will spin faster, increasing in frequency, when more energy is stored in the system. Conversely, the frequency decreases when less electricity is stored in the system. Electrical equipment can be destroyed if the frequency deviates too much from the nominal frequency, which is 50 Hz in Europe and 60 Hz in the US. If the frequency gets out of bounds, some equipment will, to protect itself, automatically disconnect, and the system will collapse. A power collapse is very costly for society, and it takes several hours to restore the system. For example, it took about 12 h to restore the system after the Great Blackout of 2011 in southwestern US. Therefore, it is imperative to keep production and consumption in balance every single minute.

It is challenging to continuously keep the system in balance. The electricity demand is often price-insensitive; for instance, many households pay a fixed price that does not fluctuate from hour to hour. Still,

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<https://doi.org/10.1016/j.esr.2022.100812>

Received 31 August 2018; Received in revised form 17 December 2021; Accepted 17 January 2022

Available online 22 January 2022

2211-467X/© 2022 The Authors.

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consumers are free to suddenly increase or decrease consumption without notice, regardless of whether the system frequency is approaching its boundary. Similarly, variable renewable energy is intermittent by nature, changing unpredictably from 1 min to the next. Besides these challenges, technical network and production constraints must be considered. For example, there are ramp-rate constraints, which restrict how quickly producers can increase and decrease their output. It normally takes 5–30 min to ramp up a thermal plant from minimum to nominal production. Ramping is particularly slow in coal plants, where the thermal stress due to temperature variations is often the limiting factor. Often ramping is even slower in nuclear power plants. The minimum production is typically 20–60% of nominal output for thermal plants. This is to ensure that the flame is stable. Other intertemporal constraints are costs involved in turning the plant on, the start-up cost, and a fixed cost of operation, the no-load cost. The intertemporal constraints imply that the cost of producing during 1 h depends on the output in adjacent hours.<sup>1</sup> One issue with the fixed cost is that the average production cost would be decreasing in some output intervals. Such non-convexities imply that a producer may require a price above its marginal cost in those intervals to avoid making a loss. To manage all of these issues and to achieve a feasible and efficient allocation, electricity production is coordinated by a system operator when electricity is delivered.

To keep the system in instantaneous balance when electricity is delivered, the system operator decides how much each plant should increase/decrease its production; thus, electricity markets have central unit commitment for changes in real-time. The system operator needs to take all aspects of the network into account. It usually needs detailed knowledge about costs, ramp-rates, and locations of plants to make technically feasible and efficient decisions in real-time. This information is partly submitted to the system operator when a production plant is registered, while some information can be submitted as part of a bid.

Whereas all electricity markets are coordinated by a system operator in real-time, there are large differences between markets regarding central coordination in planning and scheduling ahead of delivery. We say that an electricity market is *centralized* if the system operator decides how much should be produced in each plant well ahead of delivery, in the day-ahead market. Plants are often scheduled the day before delivery because many plants take hours to start up, especially if they are cold, and some have very long ramp-rates (nuclear power). The day-ahead market is sometimes called the spot market, as the day-ahead price is often used as a strike price to settle financial contracts and determine retail prices.

Decentralized electricity markets have significantly less coordination ahead of delivery. We say that a market without organized physical trading before the real-time market or that has a day-ahead market with self-commitment is *decentralized*. In this case, the producer can choose by itself how to best produce the committed output within an agreed location. It can also make an agreement with another producer to deliver the committed electricity.

The centralization versus decentralization discussion is not only relevant for the organization of electricity markets. In the economic literature, there is a related discussion about the organization of large firms [3] and on how to organize societies. One example of the latter is the famous discussion between Friedrich von Hayek, Oskar Lange and Abba Lerner about efficiency in socialist and capitalist economies [4]. Clearly, centralized decision-making would be better than decentralized decision-making if communication to the central authority was costless, perfectly informative and occurred without delay. Similar ideal assumptions have been used to motivate centralized electricity markets [5–8]. But in practice, the central authority cannot take for granted that communication is truthful [9]. One might think that centralization

would perform better when there is a greater need for coordination in the organization. But Alonso et al. [10] show that it could actually be the other way around; a greater need for coordination often means that agents will have incentives to communicate more strategically in a centralized organization.

Untruthful reporting is an issue in centralized electricity markets where producers have incentives to overstate their costs [11]. Another issue with centralized electricity markets is that restrictions in the bidding format prevent producers from forwarding all cost-relevant information to the central operator [12]. Melumad et al. [13] find that, for generic organizations, decentralization will be optimal if communication is sufficiently restricted. Also, communication and processing of information tend to be slower and less flexible in a centralized organization. For example, introducing new technologies, e.g., renewables, energy storage and demand response, is complicated in a centralized electricity market. Regional markets in the US typically have two settlements, a day-ahead market, a real-time market and no trading in between [14,15]. For many years centralized markets in the US did not give wind-power producers apt incentives to report changes in production conditions and to invest in the optimal forecasting technology. Moreover, production decisions (dispatches) were not updated in a timely and efficient manner. This has changed in PJM, where market clearing now is regularly updated during the intra-day period, between the day-ahead and the real-time market.

Regular updating of the dispatch is more straightforward in decentralized electricity markets, where products are standardized, and producers are free to bilaterally trade physical commitments with other market participants ahead of delivery. In Europe, such adjustments are made in the intra-day market. As illustrated in Fig. 1, it opens after the day-ahead market and closes before the real-time market. The intra-day market is cleared continuously or at regular points in time. Borggrefe and Neuhoff [16] argue that European intra-day markets have proven critical in accommodating large amounts of solar and wind-power because the forecast uncertainty for these technologies is significantly lower in the intra-day market compared to the day-ahead market. It is important that the dispatch can be updated with respect to new forecasts as soon as possible to minimize the cost of rescheduling units [17]. Intra-day pricing also implies that forecast errors will reduce the profit of renewable producers, which gives them an incentive to improve their forecasts and to trade on new information as early as possible [18,19]. Herrero et al. [15] show that wind-forecast errors in Spain have been reduced by approximately 50% from 2006 to 2014.

An issue with decentralized day-ahead markets is their incompleteness, meaning that producers cannot trade contracts that perfectly match individual non-convexities, indivisibilities and intertemporal costs. This deficiency is potentially eliminated by the rich sequence of markets. Producers can use intra-day trading to correct non-optimal day-ahead dispatches, for example, due to non-convexities and indivisibilities or intertemporal constraints in production. Hence, in principle, a decentralized market should, similar to multi-round auctions, be able to deal with these issues and avoid coordination failures. However, better possibilities to coordinate and other aspects of the decentralized design also increase the risk for collusive outcomes.

IEA [14] recommends that Europe should develop day-ahead markets with a finer geographical resolution. We share this view. The main problem with many decentralized markets is that network constraints are represented in a suboptimal way ahead of real-time. The day-ahead market and intra-day trading often neglect network congestion inside large regions/zones. Thus, the day-ahead and intra-day dispatch may not be technically feasible due to congestion within a zone. This leads to unnecessarily large corrections in the real-time market. The problem can be mitigated by dividing countries into several zones, as in Scandinavia and Italy, or by introducing flow-based zonal pricing, which considers congestion inside a zone. The latter approach is used in Central Western Europe (CWE). Another example is the decentralized market in New Zealand that uses locational marginal (nodal) pricing, i.e., every node of

<sup>1</sup> The empirical study by Reguant [2] shows that this effect has a strong influence on the bidding behaviour in Spain.

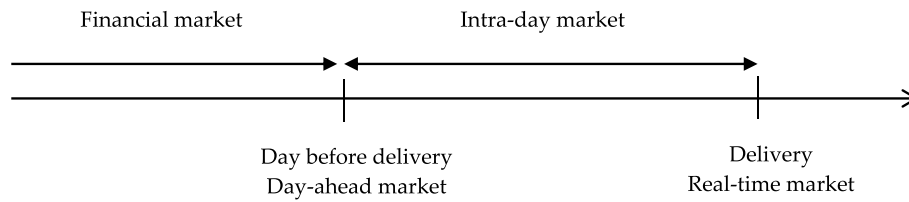


Fig. 1. The sequencing of markets in Europe.

the network has a local market price, similar to how networks are represented in the centralized electricity markets in the US. A problem with a finer geographical resolution is that liquidity in the intra-day and financial markets worsens when products become more specialized. In addition, prices at a given location become less predictable, also in the long run. This combination increases the risk and the cost of hedging risks in the electricity market which makes investments less attractive. Hence, even if a finer geographical resolution would improve short-run efficiency, it is not evident that long-run efficiency would also improve.

The US has experimented with both centralized and decentralized markets but is now converging towards the centralized design. Empirical evaluations of such reforms in America consistently conclude that they have improved short-run efficiency by 0.5%–4%, either for the market as a whole or for thermal production. It seems that a centralized design would mainly be an advantage for markets where thermal production dominates and network congestion is a major issue, which was the case for the evaluated reforms in the US. In Europe, the trend goes in the other direction. The old pool in England and Wales and the single electricity market (SEM) in Ireland were European examples of centralized markets. However, Britain and Ireland changed to decentralized markets in 2001 and 2018, respectively.<sup>2</sup> Now, all markets in the EU are decentralized or semi-decentralized. Table 1 lists examples of decentralized and centralized electricity markets around the world.

The rest of the paper is organized as follows. Sections 2 and 3 discuss centralized and decentralized electricity markets, respectively. Section 4 summarizes results from game-theoretical models that are relevant for the evaluation of the two designs. Section 5 addresses quantitative comparisons of the two designs for real electricity markets. The paper is

concluded in Section 6.

## 2. Centralized electricity markets

In a centralized electricity market or cooperative pool (poolco), producers forward cost-related information for each generation unit to the system operator. This is referred to as unit-based and capability-based bidding. The system operator has full control of all production decisions also in the day-ahead market. Likewise, the system operator of a centralized market would normally take details of the network into account when clearing the day-ahead market. As illustrated in Table 1, centralized markets would normally use nodal pricing, where each node of the network has a local market price. The dispatch is computed by minimizing the total cost of serving demand at every node in the network (or by maximizing gains of trade if demand is elastic), subject to network and production constraints. A network can contain hundreds/thousands of nodes; thus, there could be hundreds/thousands of different local prices across the network. In some ways, centralized markets imitate vertically integrated operations, and they have inherited some procedures from national monopolies and regional power pools that existed before the deregulation [1]. Hence, centralized electricity markets are sometimes called integrated electricity markets.

The main advantage of a centralized day-ahead market is to ensure that the day-ahead dispatch is technically feasible and (ideally) cost-efficient. Absent new shocks in the system, i.e., outages, demand shocks, transmission failures and variations in the renewable production, no further adjustments would be needed in the real-time market. Considering that some plants can have long ramp rates, it would indeed be efficient if the dispatch could be determined the day before delivery.

One reason why countries have been reluctant to adopt centralized designs with nodal pricing is political. Even in the US, it has proven difficult to charge electricity consumers a price that reflects the nodal price at their location in the transmission network. Those objecting often argue that it would be unfair to charge some customers higher prices due to their location in the network. In the US, such equity concerns have usually been resolved by a regulatory mandate that requires retailers to sell all electricity at the same price within a given service territory. The retailer’s wholesale cost is the quantity-weighted average of the locational prices at all nodes within that territory. This design is called Generator Nodal Pricing (GNP) [22]. It is, for example, used by the electricity market in Texas (ERCOT) and New England (ISO-NE). From an efficiency perspective, it is fine that consumers pay in accordance with such an average instead of a local marginal price if consumption anyway is price-insensitive.

The main advantage of a centralized design is that ideally it would result in an efficient day-ahead dispatch, but this is not entirely true in practice. In the remainder of this section, we discuss disadvantages and some advantages of the centralized design in further detail. One issue is that restrictions in the bidding format mean that costs cannot be reported in detail. Another is that producers have incentives to overstate their start-up costs, a problem that has been quantified by FERC [23]. New market designs have been presented in the literature, which have the potential to reduce this problem. Moreover, we discuss the financing of start-up and no-load costs and how non-linear tariffs could potentially make financing more efficient. Inflexibility is a third problem with centralized markets. It has been difficult to introduce intra-day markets,

Table 1  
Examples of centralized and decentralized electricity markets.

	Day-ahead	Nodal pricing
<b>US Markets</b>		
<i>PJM</i>	Centralized	Yes
<i>Texas (ERCOT)</i>	Centralized (from 2010)	Yes (GNP)
<i>Midwest ISO (MISO)</i>	Centralized	Yes
<i>California</i>	Centralized (from 2009)	Yes
<i>New England</i>	Centralized	Yes (GNP)
<b>European &amp; International Markets</b>		
<i>Nord Pool</i>	Decentralized	No (zonal)
<i>Great Britain</i>	Decentralized (from 2001)	No (zonal)
<i>Germany</i>	Decentralized	No (zonal)
<i>Ireland</i>	Decentralized (from 2018)	No (zonal)
<i>Spain</i>	Semi-decentralized	No (zonal)
<i>Italy</i>	Semi-decentralized	No (zonal)
<i>NEM, Australia</i>	Decentralized	No (regional)
<i>New Zealand</i>	Decentralized	Yes
<i>Chile</i>	Cost-based	Yes

<sup>2</sup> These reforms are discussed in detail by Newbery [20,21].

which are important for intermittent renewables, and to adopt the market design to new technologies. A fourth issue is that centralized electricity markets are complex and computer-intensive. Consequently, they tend to be non-transparent for traders. Also, they can be hard to scale up. These weaknesses are compensated by improvements in computer performance and clearing algorithms. A fifth issue is that the centralized market design has implications for how the system operator should be regulated. In Section 2.7, we discuss a version of a centralized market, where bids are heavily regulated. This design is mainly used in Latin America, but sometimes also in the US when local market power is demonstrated to be sufficiently high.

### 2.1. Bids provide somewhat distorted information about costs

In the US, producers typically use three-part bids that specify start-up costs, no-load costs and marginal production costs. This restriction is problematic for units with more complex cost structures [12]. For example, a Combined Cycle Gas Turbine (CCGT) unit can consist of multiple generators and turbines, in which case marginal costs would be tooth-shaped because they can switch between different operating modes as their output changes. Hence, marginal production costs can have large variations, up and down, which cannot be fully captured by a three-part bid. Another example is the cost structure of cascaded hydroelectric systems, where the optimal output of a downstream plant depends on the output of an upstream plant.

### 2.2. Make-whole payments and discriminatory pricing

One purpose of three-part bids is to separate marginal costs from start-up and no-load costs. The day-ahead dispatch will consider stated start-up and no-load costs, but locational marginal prices are normally set by stated marginal costs. Hence, most centralized markets pay compensation in addition to the electricity price to producers with start-up and no-load costs. Such compensations are referred to as make-whole or uplift payments.

Most electricity markets are organized around the idea of *marginal pricing*, or *uniform pricing*, meaning that each location has a market price set by the marginal unit. One advantage is a well-defined market price for all transactions at every specified location. This local price can also be used to define the strike price of financial products, which facilitates hedging. Another advantage is that producers do not have incentives to overstate their variable costs when offering electricity in a competitive market. But centralized markets in the US also have aspects that make them similar to a discriminatory auction because make-whole payments are based on stated start-up and no-load costs. Thus, two producers that deliver the same amount in the same node at the same time can get different payments. This type of discrimination is one issue with uplift payments. As a consequence, some producers will have incentives to overstate their no-load and start-up costs, even if the market is perfectly competitive. Moreover, producers have to estimate by how much they can overstate their costs and still be accepted. Thus profit-maximizing producers will spend more time preparing their bids, which would particularly hurt small firms. These issues are familiar for an auction with discriminatory pricing. Such an auction is also called a *pay-as-bid auction*, as each accepted offer is paid its own offer price.

FERC [23] analyzed uplift payments in the US and found that yearly average payments for different markets were in the range \$0.30/MWh-\$1.40/MWh. This is relatively small compared to corresponding average locational marginal prices, which were in the range \$28/MWh-\$57/MWh. FERC [23] showed that uplifts are concentrated to certain geographic areas: In PJM, 19 units received more than \$10 million in yearly uplift payments; in MISO 2 units received above \$10 million [23]. Large units were overrepresented among the recipients. A case that has attracted public interest was JP Morgan Venture Energy Corporation, which repeatedly exaggerated its no-load cost by up to twice its value in California's day-ahead market. In the end, they had to

pay a total of \$410 million in penalties [24].

Liberopoulos and Andrianesis [24] analyze alternative pricing schemes that have been discussed for markets with non-convex costs. For example, to avoid uplift payments, it would be possible to set market prices sufficiently high so that no plant that is called to produce would make a loss. The semi-Lagrangian relaxation (SLR) [25] and the primal-dual (PD) approach [26] are examples of such pricing methods. Similarly, Milgrom and Watt [27] show that linear prices can be used to clear markets with non-convex costs and indivisible production, and that the inefficiency introduced by linear prices is small in large markets with many participants. These pricing methods would be closer to the marginal-pricing design. Avoiding uplift payments would also give more well-defined market prices that are useful for hedging. Producers would have weaker incentives to misrepresent their costs. In general, many pay-as-bid related issues of centralized electricity markets could probably be avoided, including distorted information about start-up and no-load costs. On the other hand, there are also advantages to pay-as-bid pricing. For example, and as will be discussed in more detail later in this paper, one advantage is that collusive outcomes are less likely to occur in an electricity market with pay-as-bid pricing. Another advantage of uplift payments is that it is possible to efficiently finance start-up and no-load costs. We discuss this in the next subsection.

### 2.3. Financing make-whole payments

One issue with make-whole payments is that the auction is not budget-balanced. Hence, the market operator needs to finance these payments, for instance through a mark-up on the price paid by consumers or a fixed fee paid by participants in the day-ahead market. Either way, financing the make-whole/uplift payments will introduce welfare losses, as it will reduce the consumption of electricity. In the US markets, make-whole payments are normally financed by the market participants, for example by a membership fee mainly from producers. In this case, the fee is individual and partly proportional to the turnover of a member. Such a fee corresponds to an increase in the marginal cost of a producer, which will be passed through to consumers by an increase in the price. Thus, in the end consumers will pay a price that covers start-up and no-load costs. Similar to a market with linear prices and no uplift payments, this would introduce inefficiencies. But one could think of an alternative centralized design, where consumers pay a non-linear price for electricity, a lump-sum fee and a per-unit charge. If the lump-sum fee is used to cover uplift payments to producers, then this would improve the efficiency of a centralized design, but the surplus of consumers would be reduced. This is an example of the classical trade-off between efficiency and rent extraction; see, for example, Oi [28] and Laffont and Tirole [29]. In a centralized market with non-linear prices, it is more difficult to exaggerate costs to extract rent if there are more competitors. Therefore, the efficiency-rent trade-off is probably less important in a competitive wholesale electricity market.

In economic studies of electricity consumers, it has sometimes been argued that non-linear pricing could be too complicated for users to understand. In practice, their response may not be consistent with economic theory. For example, the empirical studies by Borenstein [30] and Ito [31] show that for highly non-linear tariffs in California, many consumers respond to average prices rather than marginal prices. This seems to suggest that our discussion above on the trade-off between efficiency and rent extraction may not be valid in practice. However, as argued by Borenstein and Bushnell [32], it should be easier for consumers to separate a recurring fixed charge and a marginal price, as in our examples above, in comparison to the highly non-linear volume-based charges in California. Also, Wolak [33] find that in the water industry, an industry which is related to the electricity industry, households' consumption responds to marginal prices even if prices are non-linear.



#### 2.4. Centralized markets are inflexible

A problem with centralized markets is inflexibility. Under centralized unit commitment in the day-ahead market, each unit has an individual commitment and a tailor-made contract, which is difficult to trade in the intra-day market. Centralized markets sometimes even use sanctions and penalties to deter producers from revising their day-ahead dispatch [1]. This has recently improved, for example, in PJM, but it used to be the case that producers had to wait until the real-time market (or an hour-ahead market) to adjust the day-ahead dispatch. Thus, a centralized market has, or used to have, slow response to shocks that occur after the day-ahead market has closed, such as changes in the prognosis of wind-power output, unplanned outages, disturbances in the network, etc. Missing intra-day prices are a problem for producers that want to make optimal updates of their dispatch [34,35], especially for plants with long ramp-rates that schedule production well in advance of the real-time market. There is a similar problem for producers with complex costs that are not well-represented by three-part bids and may therefore be dispatched in an inefficient way in the day-ahead market. A producer cannot correct its day-ahead dispatch until the real-time market (or hour-ahead market) if there is no intra-day market.

Another source of inflexibility is the time and money required to develop new bidding formats that match new technologies, such as energy storage and demand response. In the US, demand response is aggregated by authorized Curtailment Service Providers (CSP) or demand response providers, who submit bids to the electricity market on behalf of clients. Before such demand-response capacity can be used in the day-ahead market, there is a bureaucratic process through which this capacity must be verified. Often, the demand response should be able to follow dispatch orders from the centralized day-ahead market.

#### 2.5. Centralized markets are somewhat opaque and hard to scale up

The purpose of including start-up costs, no-load costs and other dynamic costs in the bidding protocol is to optimize the day-ahead dispatch. But these intertemporal costs and constraints make it impossible to separate the clearing of adjacent delivery periods. In practice, this makes it computationally challenging to clear the centralized day-ahead market in a quick and transparent way. For example, ERCOT, the system operator in Texas, has thousands of computer servers to run its systems [36]. Another aspect is that it is often not possible to find the optimal dispatch in finite time. Instead, one must settle for an approximately optimal dispatch through an iterative procedure. The number of iterations is bounded because the day-ahead market must be cleared within a limited time frame, e.g., 5–60 min. This is probably a minor problem for efficiency, but it makes the market less transparent. It becomes difficult for an outsider to replicate the clearing, so market participants really need to trust the market operator, perhaps more than they would like to. For some plants, especially units on the margin of being accepted, the scheduled output can vary greatly from one iteration to the next in the clearing process. For such plants, it is somewhat arbitrary whether the unit is dispatched or not, and it becomes difficult for the owner to understand why an offer was rejected or accepted. In this sense, a centralized day-ahead market is opaque and somewhat of a black box. Another issue is that a complex and somewhat non-transparent algorithm increases the risk of mistakes in the clearing. There are similar problems in some decentralized markets, and we come back to this discussion in Section 3.4.

Many electricity markets, such as MISO and PJM, make use of mixed-integer algorithms, and such clearing algorithms are NP-hard [37]. In such cases, memory requirements and run-times could grow exponentially with the size of the problem, such as the number of production units or the number of delivery periods that are to be cleared simultaneously.

As the scale of the system increases, it becomes harder to optimize everything simultaneously. It is still possible to require that the clearing

iterations must stop within a given time period, such as 30 min. But a larger problem to solve within a given computation time would reasonably mean that the accuracy and efficiency of the reported dispatch should go down. The scalability of the clearing algorithm is important because both Europe and the US are integrating markets across country and state borders. Similarly, the clearing procedure becomes more challenging for centralized markets with shorter delivery periods because this increases the number of interrelated delivery periods per day.

Fortunately, as markets become larger and more complex to clear, the computer performance and the performance of mixed-integer algorithms [37] have improved dramatically. Such advances have contributed to PJM's recent introduction of 5-min delivery periods.

#### 2.6. Separated transmission ownership and system operation

In centralized systems, the system operator is involved in the day-ahead market and often also in capacity markets, which take place long before delivery.<sup>3</sup> This would be an issue if these market operations would influence its profit, such as congestion rents.<sup>4</sup> To avoid this problem, system operators in the US normally do not own any transmission or reserve capacity. Hence, they are referred to as independent system operators (ISOs). However, even if transmission ownership and system operations are separated, it should still be possible for owners of the transmission grid to influence their payoff by making strategic statements of the capacity and status of the grid. As far as we know, this is an issue that has not been sufficiently analyzed by the academic literature. The role of system operators and how they should be regulated is further discussed by Pollitt [38,39], Chawla and Pollitt [40], Anaya and Pollitt [41], and Stern [42,43].

#### 2.7. Cost-based electricity market

A more invasive form of centralization is when the regulator does not trust producers to make their own bids. In cost-based electricity markets, the market operator studies generation units in detail and uses audited cost information to determine prices and dispatch. This type of market regulation is mainly used in hydro-dominated countries in Latin America, such as Chile [44]. A similar regulation is also used in the US when local market power is demonstrated to be sufficiently high [45] and in the redispatch in some European electricity markets [46].<sup>5</sup>

A cost-based market design does not necessarily eliminate the ability of producers to exercise market power. Wolak [47] notes that unless properly monitored and regulated, producers can, through transactions with affiliate companies, make fuel costs and other input costs correspond to whatever level that they would like to bid, so that a cost-based market becomes equivalent to a bid-based market. Such manipulation of input prices was, for example, observed during California's electricity crisis [48]. To avoid this, more regulation and surveillance are needed in cost-based electricity markets compared to bid-based markets.

Munoz et al. [45] discuss additional problems with cost-based electricity markets. For example, producers will invest too little in base load and excessively in peak power to push up the price if investments are unregulated. Moreover, restrictions on the number of unit start-ups due to thermal/maintenance constraints introduce an opportunity cost, i.e.,

<sup>3</sup> Capacity markets give producers an extra payment for the capacity that they provide. This subsidy increases the production capacity in the market, which lowers the risk of having black outs. Moreover, the system operator gets more control of investment decisions, which become more centralized.

<sup>4</sup> The owner of a transmission line essentially buys electricity at the cheap end of the line and sells it at the expensive end. This gives the owner of the line a congestion rent.

<sup>5</sup> In Europe, the redispatch is a real-time operation that the system operator uses to relieve congested lines inside a zone.

the payoff that the generator would earn if a start-up was delayed. Related issues are introduced by take-or-pay contracts for gas, which are used in many countries [45]. These contracts specify both a price and a quantity at the time of delivery, and a penalty for any deviation from the contracted volume. This penalty can also introduce an opportunity cost. Relatedly, Holmberg and Wolak [49] argue that daily natural gas prices can have large uncertainties due to local congestion and local storage constraints in pipelines. Moreover, the owner of a thermal plant has private information about the efficiency of its plant, which depends on the ambient temperature, and how the plant is maintained and operated. Normally, it would go far beyond the responsibility of a market/system operator to keep track of all these details and to estimate any opportunity costs that can occur. This means that cost-based electricity markets will result in a somewhat inefficient dispatch. Still, Wolak [48] argues that a cost-based dispatch can be the best solution for many countries in Latin America because it is also very expensive to set up a bid-based spot market.

### 3. Decentralized electricity markets

European markets are decentralized in the sense of allowing producers to use self-dispatch in the day-ahead market. This means that producers can choose how to deliver the committed energy at the agreed location. They are also free to pay another producer to deliver the energy instead. This arrangement is sometimes called portfolio-based bidding.

Decentralized markets acknowledge that it is necessary to have a system operator with exclusive authority to manage the power system in real-time, but its authority to intervene ahead of delivery is often limited to day-ahead scheduling of the transmission network. One purpose is to minimize the operator's monopoly influence on electricity markets [1]. For example, there are studies showing that if a system operator owns parts of the network, it has incentives to set transmission capacities that increase congestion rents and reduce redispatch costs from the network [50,51].

As system operators are less active in decentralized markets, the separation of transmission ownership and system operations is less of an issue than for centralized markets. In Europe, the system operator often owns transmission lines in accordance with the ITSO (Independent Transmission System Operator) model. The UK is an exception; it has recently decided to separate ownership of the grid from system operations.

Some European system operators have been directly or indirectly involved in the organization of the day-ahead and intra-day markets. But other markets are more decentralized. The NETA reform in the UK originally left it to the market to sort out any trading ahead of real-time. New Zealand is also very decentralized in that all trading before the real-time market is financial. Decentralized markets are therefore sometimes referred to as exchange-based, unbundled, or bilateral markets.

In Section 3.1, we discuss flexibility of trading arrangements, such as intra-day trading and less bureaucratic processes, which are important for intermittent renewables and new technologies. Section 3.2 addresses problems with continuous intra-day trading that have been observed during the last 5–10 years, and for which a solution has been presented, intra-day auctions. One advantage of decentralized markets is that they are transparent, facilitate hedging and simplify market clearing. The latter also implies that decentralized markets can easily be scaled up. We discuss this in Section 3.3. In Section 3.4, we go through advantages and disadvantages of block orders, which have been studied in the academic literature during the last 10–15 years. These are particularly useful for indivisible production and for production with long ramp-rates, but they make it harder to scale up the market and the market becomes less transparent. The main problem with decentralized markets is that zones tend to be too large. We discuss regulations and new designs that can improve the efficiency of zonal markets in Section 3.5.

#### 3.1. Decentralized markets are flexible

The electricity markets in Europe are divided into zones, and there is one spot (day-ahead) price per zone. Most European countries have one zone per country, but some countries have multiple zones. One advantage of zonal pricing is that delivering electricity in a zone becomes a standardized product that can be traded with other market participants in the secondary market, such as the intra-day market. This makes it straightforward for producers to update their dispatch whenever new information about unplanned outages, renewable output, the demand level, and network shocks arrive. Moreover, intra-day prices are frequently updated, which gives producers the right price signal when making corrections in the dispatch.

Producers can use the flexibility of decentralized markets to manage indivisibilities, non-convexities and economies of scope. Once producers have a good estimate of the price for each hour, it is straightforward to take intertemporal costs into account and to choose an optimal output for each hour. Furthermore, separate future prices for each delivery hour would facilitate the price discovery process.

Indivisibilities and non-convexities are somewhat harder to manage as the output would have to be coordinated with the output of other plants, which might be owned by another producer. For example, if there are two identical plants with the same marginal, no-load and start-up costs, and only one of the plants is needed, then producers need to coordinate their decisions so that exactly one plant is started. Still, in case producers misestimate prices or make coordination mistakes, they can correct the dispatch in the intra-day market. Moreover, day-ahead markets are repeated daily, with small variations between days. Thus, producers have experience from previous auctions that will help them predict prices and get coordination approximately right in the first physical market, the day-ahead market [1]. In addition, large producers would be able to work around some non-convexity/indivisibility issues in decentralized markets by adjusting their internal production schedules.

Letting producers sort out issues with economies of scope and coordination by way of forward, day-ahead, and intra-day markets is related to the multi-round auctions that are typically used for trading interrelated items, such as spectrum licenses for neighboring regions [52–54]. During the late 1990s, the California Power Exchange considered a multi-round auction in the day-ahead market, but the idea was never implemented. Wilson [55] outlines design details for such an iterative power exchange.

One advantage of a decentralized design is a flexible market organization that would also work for new technologies, such as demand response and energy storage. As long as forward, day-ahead and intra-day markets provide adequate prices for each delivery hour, owners of energy storages can, on their own, decide when to buy and sell electricity, and consumers with demand response can decide how to shift their load. This could be done manually or automatically. A retailer will bid on behalf of its aggregated consumers. In a decentralized electricity market, the retailer can predict the aggregated demand response of its customers from historical data. Hence, demand response can be introduced without involving a Curtailment Service Provider that verifies the capacity of the demand response and/or takes control of the demand response. Moreover, demand response can be used without introducing new bidding formats. In this way, decentralized day-ahead markets are more flexible and less bureaucratic than centralized markets. A long-run advantage of letting the market sort out the organization of day-ahead and intra-day trading is that this should lead to a more dynamic and innovative organization of trading.

#### 3.2. Issues with continuous trading in intra-day markets

Currently, many European markets have continuous intra-day trading. This means that the clearing process needs to be quick, and often there is not time to fully consider transmission constraints in the

grid [56]. Hence, it has been problematic to price transmission capacity between zones [57]. There have been cases where transmission capacity has been allocated free of charge on a first-come, first-serve basis. Then, the scarcity value of transmission capacity was collected by fast traders instead of the network owner, which would be more efficient. Another challenge with continuous intra-day trading is that it encourages automatized (algorithmic), high-frequency trading. This means that the number of orders will surge, which can be overwhelming for a continuous market. Moreover, the possibility of high-frequency trading means that traders get incentives to engage in inefficient rent-seeking activities. By investing in speed, it becomes possible to make a rent on public information [58].

Frequent intra-day auctions, as in Spain, means that network constraints can be considered in a less approximative way in the intra-day market [57]. Moreover, auctions are more reliable and less likely to have breakdowns. In addition, bidders do not get any rent from investing in speed, which reduces inefficient rent-seeking activities.

### 3.3. Decentralized markets facilitate hedging and simplify market clearing

In decentralized markets producers receive (and consumers pay) a local price in their zone. This means that the market is budget-balanced. Moreover, it is easier for producers to hedge their profits if transfer prices are at zonal spot prices, which in turn can be used as strike prices for financial contracts. In the long-run, more straightforward and effective hedging should be beneficial for investments.

Another advantage of decentralized markets is the decoupling of delivery periods, so that the day-ahead market is transparent, easy to clear, and easy to scale up. Decentralization implies that each individual producer needs to estimate prices and determine its optimal dispatch contingent on those estimates. Potential problems of decentralized markets are the transaction costs associated with production planning and intra-day trading. Such costs arise also for retailers that represent consumers with demand response.

A producer with non-convexities such as decreasing marginal production costs, would sometimes need to offer its supply at a price above its marginal cost to avoid a loss. Such mark-ups generate welfare losses, as the mark-ups reduce demand. These losses are likely to be higher than in a centralized market. But, as discussed in Section 2.3, it depends on how up-lift payments are financed in the centralized market.

### 3.4. Block orders and complex bids

The Nordic and other European countries allow market participants to use block orders [59]. A block bid is a fill-or-kill order; it cannot be partially accepted. Block-bids assist in managing indivisibilities in production plants. They can also be used to manage non-convexities, for example, by fixing the output at the optimal production level of a plant.

In the Nordic countries, a block bid can span several hours. The bid is only accepted if the average price during those hours is sufficiently high. Thus, producers can use block bids to manage economies of scope, no-load costs and start-up costs. Block orders replicate some aspects of centralized markets, but there are also crucial differences. First, block orders are more flexible. If a producer wants to increase its output for 1 h in the block, it can simply sell more for that hour in the intra-day market (independent of other hours in the block). Second, the offer price of a block should consider all costs, including no-load and start-up costs that need to be covered if the block is accepted. This avoids the need for uplift payments, and there are no issues with budget imbalance and discriminatory pricing.

A block order shares with centralized markets that it introduces intertemporal coupling between delivery periods, which slows down the clearing and is hard to scale up. An incident at Nord Pool illustrates the problem with having a non-transparent clearing. In November 2021, there was a mistake in an updated algorithm that computed the spot price, and it took two weeks before anybody noticed that something was

wrong with the price. To reduce the computational complexity, one could put restrictions on block-orders [60,61]. Meeus et al. [59] argue that it is mainly the number of block types (composition) that affect the computation time, while the number of blocks and their size are less of an issue.

Their complexity is a major problem with block orders. Also, as argued earlier, the flexibility provided by intra-day markets should be sufficient to deal with non-convexities and ramp-rates. Hence, it seems that block orders could have larger drawbacks than advantages.

Spain encourages producers to make unit-based, multi-part bids, which is similar to a centralized market [62]. Reguant refers to such bids as complex bids. But Spain is decentralized in other aspects. One could say that Spain is a semi-decentralized market, as a producer is free to self-dispatch its plants as long as it delivers the committed energy within each regulation zone [62,63].

Italy has unit commitment for large plants, above 10 MW, in the day-ahead market [62]. Unlike typical centralized markets, Italy's main purpose with unit commitment is to reduce arbitrage opportunities; different technologies and participants have different spot prices in Italy. Also, each plant can adjust its trade in the intra-day market. Hence, we say that the Italian market is semi-decentralized.

### 3.5. Inefficiencies due to zonal pricing

The main problem associated with decentralized markets is that zones tend to be too large. This means that intra-zonal constraints are not properly accounted for in the day-ahead and intra-day markets. But when electricity is to be delivered in real-time, all relevant technological constraints must be considered. This makes the real-time adjustment unnecessarily large. It would be more efficient to get the dispatch right earlier on when more plants are able to adjust their output.

Another problem with zonal pricing is that different representations of the transmission constraints in the day-ahead and real-time market result in partially different prices in the two markets. This gives producers an arbitrage opportunity, which increases real-time trading even more. As shown by Harvey and Hogan [64,65], Dijk and Willems [66], Holmberg and Lazarczyk [67], Sarfati and Holmberg [68] and Hesamzadeh et al. [69,70], a producer in an export-constrained node can increase its profit by selling more in the day-ahead market at the zonal price and then buy back power at a lower local (discriminatory) price in the real-time market. This kind of bidding behavior is referred to as the increase-decrease (inc-dec) game. As explained by Alaywan et al. [71], this game contributed to the electricity crisis in California. According to Neuhoff et al. [72], there have also been problems with the inc-dec game in the British electricity market. Graf et al. [73] find that the Italian market has considerable problems with the inc-dec game and related arbitrage strategies. Hirth et al. [74] estimate that the redispatch volume in Germany could increase by 300–700% due to the inc-dec game if Germany would deregulate the redispatch market.

California and other markets in the US switched from zonal to nodal pricing to avoid the inc-dec game [71]. In Europe, the problem with arbitrage gaming can be mitigated by reducing the size of zones. For example, Denmark, Norway, and Sweden have at least two zones per country. New Zealand is an example of a decentralized day-ahead market that uses nodal pricing. EU is advocating flow-based zonal pricing [75], which has been implemented in Central Western Europe (CWE). In an approximate way, this approach considers the most critical congested lines inside a zone, while maintaining one price per zone. This zonal approach should mean that it will be sufficient with small real-time adjustments of the dispatch, even if the zones are large. Simulations by Sarfati et al. [76] confirm that flow-based pricing can mitigate the inc-dec game and reduce welfare losses in a zonal market. However, flow-based pricing reduces trade between zones, which could be inefficient, and would be inconsistent with EU's plan that cross-border trade should increase. Sarfati and Holmberg [68] show that the inc-dec game can also be mitigated by a change in the design of the

real-time market. Another alternative is to regulate the redispatch market as in Germany and the UK [74].

Australia's National Electricity Market (NEM) applies an alternative form of zonal pricing, which is sometimes referred to as regional pricing. In this market, the dispatch takes all network constraints into account. Thus, the dispatch would be as efficient as nodal pricing if all producers would make offers in accordance with their costs. Unfortunately, all producers do not have incentives to state their costs correctly, even if the market is competitive. The price in each region is set by the nodal price in a reference node. This means that for an import constrained node, where the local price should be high, the market operator can accept units with a marginal cost above the reference price. Still, units in that node are only paid the reference price, so such a unit is said to be *constrained on* [77]. Obviously, a firm will do its best to avoid a situation where it makes a loss. Thus, units at risk of being constrained on will overstate their cost. In import-constrained nodes, producers would sometimes need to raise the offer price all the way up to the price cap to make sure that the auction accepts an offer from a competitor instead. In Australia, this is known as disorderly bidding [77]. Similarly, in export constrained nodes, production units with a marginal cost below the reference price are at risk of being constrained off, i.e., offers are rejected even if they are willing to produce at the reference price. Such units sometimes undercut each other down to the price floor to ensure that the units are accepted and paid the reference price. Similar to the European zonal designs, the problem with disorderly bidding can be mitigated by reducing the size of zones.

#### 4. Market power in decentralized and centralized markets

Decentralized markets tend to rely on competition and a good market design to incentivize market participants to behave efficiently. Centralized markets use relatively more command, control, and the threat of penalties to incite producers to make efficient decisions [1]. But also in such markets, performance is improved by better competition. For example, producers have fewer possibilities to overstate no-load and start-up costs in a competitive market.

In practice, electricity markets are oligopoly markets with imperfect competition. Market concentration in wholesale electricity markets as measured by the Herfindahl-Hirschman Index (HHI) is typically in the range 1000–2000, both in Europe [78] and the US [79]. This degree of market concentration corresponds to a market with 5–10 symmetric suppliers. For markets with 10 (uncontracted) suppliers (and no network congestion), Holmberg and Newbery [80] estimate that the deadweight loss is below 1% of the total producer profits. In practice, the exercise of market power in electricity markets can be unproblematic at some times and excessive at other times. The latter occurs when only a few producers compete for the marginal load. The switch from non-problematic to problematic market power is more pronounced in electricity markets compared to most other markets. One reason is that electricity is expensive to store [81].

In this section, we will discuss market power and how it interacts with non-convexities and how it influences the evaluation of centralized and decentralized markets. The discussion focuses on the progress that has been made during the last 20 years. In Section 4.1, we give a brief introduction to game-theoretic modeling. In Section 4.2, we go through relevant game-theoretic evaluations of market designs. Section 4.3 focuses on ill-behaved outcomes where prices are at the collusive level, which is a potential problem, especially for decentralized markets. Section 4.4 discusses forward contracting, which can mitigate problems with market power.

In Tables 2 and 3, we summarize some issues and remedies we identify for centralized and decentralized day-ahead markets, respectively.

**Table 2**

Some issues and potential remedies for centralized day-ahead markets.

Issue	Remedy
<b>Slow market response to updated wind prognoses</b>	Introduce intra-day clearing
<b>Budget imbalanced due to uplift payments</b>	1) Design tariffs to minimize welfare losses, subject to an acceptable welfare distribution. 2) Achieve budget balance by setting market prices sufficiently high so that no plant that is called to produce would make a loss.
<b>Uplift payments give discriminatory pricing, which causes inefficiencies.</b>	1) Restrict offers to have a shape/slope that is similar to the shape/slope of the marginal cost. 2) Avoid discriminatory pricing by setting market prices sufficiently high so that no plant that is called to produce would make a loss.
<b>Non-transparent market and inefficient hedging due to uplift payments.</b>	Avoid uplift payments by setting market prices sufficiently high.
<b>Illiquid financial markets due to nodal pricing.</b>	Use frequent auctions instead of continuous trading in financial markets.

**Table 3**

Some issues and potential remedies for decentralized day-ahead markets.

Issue	Remedy
<b>Inefficient allocation of transmission capacity and congestion rents in intra-day market.</b>	Replace continuous trading with frequent auctions in intra-day market
<b>Collusive bidding</b>	Restrict the number of intra-day auctions.
<b>Inefficiencies due to zonal pricing</b>	1) Increase the number of zones, especially for producers. 2) Introduce flow-based zonal pricing 3) Regulate redispatch market
<b>Complex and non-transparent market</b>	Avoid block orders

##### 4.1. Introduction to game-theoretic modeling

Market designs are normally evaluated by comparing market equilibrium outcomes. Competitive markets are often modeled as Walrasian equilibria, where costs are assumed to be convex and producers are assumed to be small so that the decision of an individual producer has negligible influence on the market price [82–85]. This convenient approximation implies that the supply of electricity is equal to the aggregated marginal cost of producers. Scarf [86,87], Villar [88], Bonnisseau and Medecin [89], as well as Fuentes [90] extend the Walrasian equilibrium to consider non-convexities.

In oligopoly markets, producers have incentives to offer electricity above the marginal cost, which makes it more complicated to predict market supply. Imperfect competition is normally evaluated by game-theoretic models. In this case, it is assumed that each producer chooses offers that maximize its expected profit, given strategies chosen by its competitors. One can then solve for a Nash equilibrium (NE) where all producers maximize their profits simultaneously. It is an equilibrium in the sense that no producer has incentives to unilaterally deviate from this outcome. A NE is called a pure-strategy NE if each producer uses a deterministic strategy, while producers would use randomized strategies in a mixed-strategy NE. Mixed-strategy NE occurs when a player would lose if its strategy were predictable. This is, for example, evident in the rock-paper-scissors game. Mixed strategies can also occur when producers compete in a market. If an offer is flat, i.e., the output is very sensitive to the market price, a competitor would often find it optimal to slightly undercut that offer. This is normally not optimal for the firm making the flat offer. In equilibrium, the price of a flat offer would often



be partly randomized to make it less predictable.<sup>6</sup>

In practice, it will be difficult for market participants to find the equilibrium right away, but if the auction is repeated many times, then the market should find an equilibrium in the end. Empirical studies of the wholesale electricity market in Texas (ERCOT) show that offers of the two to three largest producers in this market roughly match the optimality conditions of a Nash equilibrium, while the fit is worse for small producers [92,93]. Wolak [94] shows that observed offers, both from small and large firms, in Australia are consistent with the market being in a Nash equilibrium.

#### 4.2. Game-theoretic evaluations of market designs

Sioshansi and Nicholson [8] use a game-theoretic model to compare the bidding behavior in centralized and decentralized markets. They consider a symmetric duopoly, where each producer has one unit with a start-up cost and a flat marginal cost. They assume that producers must make a flat offer per unit in its statement of the marginal cost. Producers compete to serve a load that is certain, common knowledge, and insensitive to price changes. They then compare the outcome for a centralized market (with two-part offers and uplift payments) and the decentralized market. Flat offers give producers an incentive to undercut each other. In the low-demand case, the production capacity of each unit is sufficient to serve demand, so that no firm is *pivotal*. In this case, producers will undercut each other until the profit is zero, similar to a pure-strategy Bertrand game.<sup>7</sup> This will change in the pivotal case, where both units are needed to serve demand. In that case, equilibrium mark-ups will be positive, and both markets will have NE where producers trying to undercut each other will generate volatile bidding, similar to a mixed-strategy equilibrium in a Bertrand-Edgeworth game.<sup>8</sup> In this equilibrium, prices will vary unpredictably even if the underlying market fundamentals are stable. For this equilibrium, expected profits are the same in both auctions [8]. Fabra et al. [95] have proven a similar revenue-equivalence result for uniform-price and discriminatory auctions without start-up costs. Wang et al. [96], Wang [97] and Andriani et al. [98,99] extend some of the results in Sioshansi and Nicholson [8] to asymmetric producers (which have different costs) and to alternative designs of uplift payments.

In the decentralized market, the randomized bidding behavior found by Sioshansi and Nicholson [8], and in the related study by Fabra et al. [95], is driven by flat offers. In a decentralized market, offers would normally not be flat unless the bidding format explicitly requires offers to be flat [49,100,101]. But in a centralized market with uplifts, total offers – including start-up costs, etc. – should, at least in theory, be fairly flat even if this is not required by the market design. The reason is that an accepted offer is paid in accordance with stated costs, so producers have incentives to bid as under pay-as-bid pricing. A profit-maximizing producer would overstate the costs for each unit so that, in theory, all accepted offers would be close to the margin of being accepted. Thus, the pay-as-bid aspect of the up-lift payments encourages producers to make offers that are very sensitive with respect to the price, which can lead to volatile bidding. Anderson et al. [102] show that this type of price instability can introduce significant efficiency losses in markets with

increasing marginal costs. Results in Holmberg and Wolak [49] and Anderson and Holmberg [101] suggest that inefficiencies caused by volatility can be reduced if the market operator restricts offers to have a shape/slope that is similar to the shape/slope of the marginal cost. For example, if each plant has a constant marginal cost independent of output, it should be beneficial to restrict the number of steps in the offer stack of a producer so that it is equal to the number of plants. In a centralized market, one could instead restrict each producer to make one offer per unit, as in Colombia [103].

Production costs are, to a large extent, common knowledge, but each supplier also has some private information. Holmberg and Wolak [49] find that marginal pricing is more pro-competitive than pay-as-bid pricing when market participants have asymmetric information. This suggests that decentralized markets would be better at dealing with asymmetric information compared to centralized markets with uplift payments.

#### 4.3. Prices at the collusive level in decentralized markets

We have mentioned some disadvantages of uplift payments and discriminatory pricing, but there are also advantages. One advantage is that each offer becomes price-setting (influences the payoff from its associated plant). This gives producers fewer degrees of freedom when they prepare their offers, and this reduces the set of equilibrium outcomes. This means that the worst equilibrium outcomes can be avoided in a centralized market, which may not be the case in a decentralized market. For example, in the case where producers are pivotal with certainty, Sioshansi and Nicholson [8] find that the decentralized market has a high-price, pure-strategy NE, in addition to the mixed-strategy Nash equilibrium discussed in Section 4.2. In the high-price equilibrium, one producer sets the price at the price cap and the other producer bids sufficiently low to avoid being undercut.<sup>9</sup> Hence, prices can be at the collusive level, even if producers do not collude. Moreover, due to the existence of such an equilibrium, it would be easier to collude as such an agreement would be self-enforcing. For the high-price equilibrium, the decentralized auction will be significantly worse for consumers than the centralized auction. The high-price equilibrium could also lead to inefficient production.

In theory, the high-price equilibrium can only exist if producers are 100% certain to be pivotal, which is rarely the case in most electricity spot markets. Bidding in electricity spot markets [92–94] and experimental results by Brandts et al. [106] are inconsistent with the high-price equilibrium and closer to the equilibria where producers are somewhat uncertain of their pivotal status. In this case, we predict that auctions would be revenue equivalent, as in Section 4.2, at least for the simplified settings considered by Sioshansi and Nicholson [8]. Still, one concern is that measures that help producers to coordinate start-ups and non-convexities in decentralized markets, such as increased transparency and iterative trading, could also help producers to coordinate prices [107]. Fabra [108] shows that producers have stronger incentives to collude in a uniform-price auction compared to a pay-as-bid auction, which speaks in favour of centralized markets with uplift payments.

Mookherjee and Tsumagari [109] consider the problem of centralization versus decentralization when producers have the option to collude to increase their profit. They assume that the unit variable costs are private information and unobservable to outsiders. Start-up costs are known (and set equal to zero). A key finding of their paper is that since the electricity produced in the two units are substitutes for one another, centralization is a more efficient market design.

<sup>6</sup> In practice traders may not use randomized strategies in the market. Haranyi [91] showed that the market outcome would be the same if each firm observes small random variations in its costs, which are not observable by competitors, and the firm chooses a deterministic strategy based on this private information. This equivalence result is called the purification theorem.

<sup>7</sup> This is a classical game where producers compete with flat offers. Note that a competitor does not gain anything from undercutting a producer if the flat offer equals the marginal cost. Hence, it is possible to have pure-strategy equilibria with flat offers at the marginal cost.

<sup>8</sup> This is a version of the Bertrand game where production constraints are considered.

<sup>9</sup> Neglecting start-up costs, von der Fehr and Harbord [104] have shown that there is a similar high-price equilibrium in the uniform-price auction. The high-price equilibrium has been observed in the capacity market of New York State's electricity market, which is dominated by one supplier and where the demand variation is small [105].

#### 4.4. Contracting in centralized and decentralized markets

Financial contracts are useful to hedge the risk of market participants. But it is also well-known from Allaz & Vila [110], Newbery [111], Green [112], Wolak [94,113], Cramton [114], and Holmberg & Willems [115] that hedging reduces a producer's incentive to exercise market power. The intuition is that a firm that has hedged a large fraction of its output gains less from increasing the day-ahead price. Many large electricity companies are vertically integrated between production and retailing. This has the same effect as contracting. A vertically integrated producer that has committed to sell a large fraction of its output at a predetermined price to its consumers gains less from an increased spot price.

The old California design of the electricity market prevented large utilities from taking forward positions, and this contributed to the crisis in 2000–2001. Bushnell et al. [116] find that if PJM and New England had prevented contracting in a similar way, it would have increased production costs by 45%. Therefore, it is interesting to study how different market designs and the organization of retailers influence the contracting incentives.

In Europe, retail and distribution are separated. This is referred to as the retail competition model [77]. This differs from the US, where distribution and retail are often bundled into regulated Load Service Entities (LSEs), as in the wholesale competition model [77]. Retailers in Europe and corresponding Load Entity Services (LES) in the US offer electricity at a fixed price to many consumers. This exposes them to a considerable risk. Hence, they have incentives to buy electricity in the forward market. Retailers in Europe typically have thin margins, which make them risk-averse and particularly keen to hedge [117]. Large LSEs in the US would have significant buyer power, and this could stimulate contracting and reduce mark-ups in the spot market, as shown by Anderson and Hu [118] and Ruddell et al. [119].

Centralized electricity markets have nodal pricing. One concern is that the multiplicity of prices to hedge will undermine liquidity in forward markets. In the US, there is sufficient liquidity in trading hubs, and also the liquidity in the US has been supported by auctions of financial contracts [120]. Still, it could be difficult to find a counter-party and a stable forward price in a local node away from a hub. This could make hedging less attractive.

Tangerås and Wolak [121] show that when there is imperfect competition, contracting is influenced by how the market design deals with network congestion. They demonstrate that due to improved contracting incentives for producers, it is an advantage that consumers in some US markets pay a uniform quantity-weighted price in each service territory, in line with the GNP design. There is a similar design in Italy, where consumers pay a uniform price, whereas producers have different prices depending on the geographical location. They show that such a design improves market performance in imperfectly competitive wholesale electricity markets substantially beyond the level that would exist if there were location-specific forward prices. This works because contracting acts as a credible commitment to behave aggressively in the short-term market, which tends to make competitors less aggressive [110]. However, increasing the volume sold in the forward market also reduces the forward price. But this price reduction is smaller in a larger market. This causes firms to sell a larger share of their output in the forward market when there is one large forward market compared to the case when there are many local forward markets. Similarly, a design where consumers pay a uniform quantity-weighted price should increase the degree of vertical integration.

#### 5. Quantitative comparisons of centralized and decentralized markets

During the last 15 years, researchers have made efforts to make quantitative evaluations of real electricity markets to study whether the centralized or decentralized design is most efficient. In Section 5.1, we

discuss simulation-based comparisons. In Section 5.2, we discuss empirical evaluations. Results for both methods indicate that centralized markets are more efficient in the short run for electricity markets in America.

##### 5.1. Heuristic-based simulations

Ideally, one would evaluate market designs by means of Nash equilibria. But existing equilibrium-oriented comparisons of centralized and decentralized markets are limited to simplified duopoly markets, as in Sioshansi and Nicholson [8]. Elmaghraby et al. [122] and O'Neill et al. [123] outline computational approaches that could potentially be used to solve for equilibria in electricity markets with non-convexities. But unfortunately, it is computationally challenging to use a game-theoretic approach to evaluate large markets with many plants and producers. Sioshansi et al. [12] have simulated the market in New England using a heuristic-based approach. They assume that producers would bid truthfully in centralized markets, which contradicts our discussion about distorted cost information in bids of centralized markets with uplifts and the findings in Sioshansi and Nicholson [8]. As a result, Sioshansi et al. [12] find that the centralized market is efficient and without mark-ups associated with pay-as-bid pricing. To reflect coordination problems in a decentralized market, they consider a heuristic winner-determination rule with an inefficient dispatch. Sioshansi et al. [12] find that electricity prices in New England would be higher for a decentralized design compared to a centralized design. Moreover, the centralized system has 4.25% less welfare loss. Camelo et al. [124] make related simulations for the Colombian market, where they find that a centralized market would reduce welfare losses by 3.32%, compared to a decentralized market. The heuristic simulations neglect that repeated trading and intra-day trading should mitigate coordination issues for decentralized markets. Hence, the simulations are likely to exaggerate the advantages of centralized designs, even though they are in line with empirical evaluations of reforms in the US and Colombia.

##### 5.2. Empirical evaluation of centralized and decentralized markets

On December 1, 2010, ERCOT, the electricity market in Texas switched from a decentralized to a centralized market design. At the time of the reform, nearly 80% of the production in Texas was from coal and gas plants. Zhang [125] has evaluated this policy reform and finds that the new centralized design reduced production costs by around 0.5%. Zarnikau et al. [126] find that spot prices were reduced by 2% on average. Triolo and Wolak [127] find that the new design in Texas reduced production costs in thermal plants by 3.9% (for a given output), mainly by improving the coordination of coal and gas plants. During the ERCOT redesign, the day-ahead market also changed from zonal to nodal pricing and the length of delivery periods was shortened from 15 to 5 min [126]. It is thus somewhat unclear whether the improvement in efficiency comes from the centralization of the day-ahead market or higher time/geographical resolution of the day-ahead market.

Wolak [128] finds that, when controlling for output, the average production cost of natural-gas-fired production units was reduced by 2.1% when California switched from a zonal design to a centralized design in 2009. Approximately 60% of the installed generation capacity in California was natural gas-fired in 2009. The remaining capacity was nuclear, hydroelectric, wind or solar. Wolak [128] argues that the scheduling of those technologies is less influenced by the market design.

In 2009, Colombia changed from self-commitment to central commitment in the day-ahead market. In an econometric study, Riascos et al. [129] find that the change improved production efficiency, even if the transition resulted in more strategic bidding and higher electricity prices. Hence, the efficiency gains were captured by producers.

Mansur and White [130] empirically estimate the net benefit of nineteen Midwest-based firms becoming members of PJM instead of trading bilaterally. It was expensive to implement this change, around

\$40 million. But this was a non-recurring cost. The estimated yearly efficiency gains were much larger, \$163 million/year. Mansur and White [130] believe that efficiency gains mainly arose from improved information about network congestion.

In summary, empirical evaluations of centralization reforms in America consistently conclude that they have improved short-run efficiency by of the order 0.5%–4%, either for the market as a whole or for most of the thermal plants. Results are probably driven by two things: improved time/geographical resolution in the day-ahead market and by having more coordination of dispatch decisions in the day-ahead market. Wolak [128] argues that having a high geographical resolution is particularly important in US markets, where network investments have been small for decades and congestion is a major issue. Another issue with network congestion is that welfare losses due to imperfect coordination could potentially be relatively large also in a large market. In theory, one would expect welfare losses to be negligible compared to the total welfare in a large well-integrated market, at least under the market assumptions made by Milgrom and Watt [27]. Triolo and Wolak [127] stress the importance of the coordination of thermal plants. Hence, it could also be argued that centralized commitment in the day-ahead market is particularly important for markets dominated by thermal production, for which the output is predictable and non-convexity issues are particularly pronounced.

## 6. Discussion and conclusions

The US has centralized wholesale electricity markets, while most of Europe has decentralized wholesale electricity markets. In centralized markets, producers submit detailed cost data to the day-ahead market, and the market operator decides how much to produce in each generation unit. This differs from decentralized markets that instead rely on self-commitment and where producers send less detailed cost information to the operator of the day-ahead market. Ideally, centralized electricity markets would be more efficient, as the clearing process considers more detailed information, such as start-up costs and no-load costs. However, the cost information that the market operator receives is imperfect. The bidding format is somewhat simplified and does not allow producers to express all details in their costs. This is a particular problem for plants with complex cost structures, such as CCGT and cascaded hydroelectric systems. Moreover, due to uplift payments, producers have incentives to exaggerate their costs, which can lead to inefficiencies. Alternative pricing schemes have been discussed in the literature, and some of them avoid uplift payments.

In general, centralized markets are less flexible. The bidding format and clearing mechanism need to be updated when new technologies arrive on the supply or demand side. Also, it has been difficult to organize intra-day markets in centralized markets, which makes it hard for producers to continuously update their dispatch as the forecast for renewable output changes. Recently, PJM has introduced intra-day clearing, which is a great improvement.

Centralized markets with uplift payments are not budget-balanced. In this paper, we argue that there is a trade-off between rents and efficiency when designing tariffs that are used to cover the uplift payments. Another issue with centralized markets is that they are very computer intensive and NP-hard to scale up. This is a potential problem as the global trend is to increase the geographical size of electricity markets and to shorten the length of delivery periods. On the other hand, the computational performance and the performance of clearing algorithms are also improving over time. The iterative and computer-intensive clearing process means that centralized electricity markets are somewhat non-transparent, so market participants need to have a high trust in the system operator. The system operator clears centralized day-ahead markets. Hence, transmission ownership should be separated from system operations to reduce the incentives of the system operator to clear the day-ahead market in a strategic way.

Intra-day markets are more flexible, and it is easier to deal with

renewable power in decentralized markets. Iterative intra-day trading in a decentralized market can also be used to sort out coordination problems related to non-convexities and intertemporal constraints in the production. But iterative trading also increases the risk of collusive outcomes. Continuous intra-day trading has problems with how to deal with inter-zonal congestion in an efficient way. Frequent intra-day auctions would avoid this issue. Intra-day auctions would also improve liquidity and reduce the risk of collusive outcomes. Self-dispatch means that more of the data processing and dispatch optimization has been delegated to producers, which should increase their costs. Transaction costs are likely to be higher in a decentralized market. Block orders reduce this problem somewhat, but on the other hand, they also introduce some of the drawbacks of a centralized market. It seems that decentralized markets might function better without block orders. Financial markets and hedging work better for decentralized markets with zonal pricing, and this should benefit investments and long-run efficiency. Still, we believe that European decentralized day-ahead markets can be improved by considering network constraints in more detail. Many countries would benefit from reducing the size of their zones, especially on the supply side. For political reasons and to encourage producers to sell more in the forward market, there are advantages with having large zones for consumers (and smaller for producers). The flow-based approach that is advocated by the EU is an alternative that should improve market efficiency without reducing the size of the zones.

Quantitative comparisons of decentralized and centralized electricity markets in America find that the latter is more efficient, at least in the short run. It seems likely that a centralized design would mainly be an advantage for markets where thermal production dominates and network congestion is a major issue. The problem is that it is more difficult for a producer to find a counter-party and a stable forward price at its node in a centralized electricity market. This is bad for investments and long-run efficiency. This might partly explain why most centralized markets use capacity markets, which the system operator can use to coordinate and ensure investments.

## Credit author statement

**Victor Ahlqvist:** Draft, Investigation. **Pär Holmberg:** Conceptualization, Methodology, Formal analysis, Draft, Reviews and editing, Preparation, Funding acquisition. **Thomas Tangerås:** Formal analysis, Draft, Reviews and editing, Project Supervision and administration.

## Declaration of competing interest

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

## Acknowledgments

This work has been supported by the Energiforsk research program EFORIS, the Swedish Energy Agency (projects 46227-1 and 47537-1), and the EPSRC grant number EP/R014604/1. We are grateful for comments from five anonymous referees, from the board of EFORIS, and for comments from the audience at the workshop on Flexible operation and advanced control for energy systems at the Isaac Newton Institute, University of Cambridge. Pär Holmberg would like to thank the Isaac Newton Institute for Mathematical Sciences for support and hospitality during the programme Mathematics of Energy Systems when work on this paper was undertaken. We are also grateful to Henrik Hällnerfors and Didrik Prohorenko, who helped us edit the paper.



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