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Review of electricity market design challenges and recommendations

Report for Cornwall LEM project

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The Cornwall Local Energy Market is part-funded by European Regional Development Funds under the European Structural and Investment Funds Programme 2014-2020.

Executive summary

In the context of the Cornwall Local Energy Market (LEM) project, this report aims at reviewing key challenges and providing relevant recommendations associated with the design of electricity markets in the envisaged low-carbon energy future. Therefore the report starts by setting out the policy framework around the decarbonisation of the UK energy system and the role and value of flexibility in facilitating a cost-effective transition to the low-carbon energy future, with a particular focus on local, distributed forms of flexibility that the Cornwall LEM project investigates, including demand side response and energy storage. Considering the multiple value streams of such flexibility, the report continues by identifying and analysing the main barriers towards recognising these value streams in the deregulated electricity market, and providing relevant recommendations. Finally, the report summarises the state-of-the-art research and practical experience associated with three key aspects of every electricity market design: bidding structures, market power issues and level of decentralization.

Decarbonisation of energy systems and need for flexibility

Energy systems across the world are currently undergoing fundamental changes, mainly driven by the continuously increasing levels of greenhouse gases emission in the atmosphere and the associated environmental and climate change concerns. In the United Kingdom, the *2008 Climate Change Act* set a legally binding target of 26% reduction in greenhouse gases emissions by 2026 (with respect to the 1990 baseline), extended to a further ambitious target of 80% reduction by 2050. In the context of addressing the above environmental and energy security concerns, energy systems are facing the challenge of decarbonisation. At the generation side, this decarbonisation is already under way through the wide deployment of renewable and other low-carbon (such as nuclear) generation sources. However, the majority of these sources are inherently characterized by high variability and limited predictability and controllability, and reduce system inertia, implying that conventional generators need to remain synchronised in the system and operate part-loaded with less cost efficiency. Moreover, the large-scale connection of renewable generation to transmission and distribution grids creates certain network challenges, such as thermal congestion, increased voltage levels and increased short-circuit currents, which threaten the security of these grids. At the demand side, significant decarbonisation of the heat and transport sectors is expected beyond 2030, with the introduction of *electric vehicles* (EV) and *electric heat pumps* (EHP) respectively. This will lead to disproportionately larger demand peaks than the increase in the total electrical energy consumption, due to the temporal patterns of users' heating and driving requirements, implying that a significant amount of new generation and network capacity needs to be built in the coming years, and this capacity will be significantly under-utilised as it will be used only to cover the increased demand peaks.

Given the above fundamental techno-economic challenges associated with the decarbonisation of energy systems, a clear need emerges for enhancing their flexibility through the efficient integration of new technologies. The Cornwall Local Energy Market (LEM) project focuses specifically on local, distributed forms of flexibility, including distributed demand side response and distributed energy storage. Suitable coordination of such distributed forms of flexibility has the potential to avoid energy curtailment from renewable generation sources, reduce the operating costs associated with the provision of reserve and frequency response services and limit the need for capital intensive investments

in low-carbon generation capacity, conventional generation capacity and network reinforcements. According to studies undertaken by Imperial College the size of the above system wide benefits in the UK is very significant - between £3.2bn and £4.7bn per year in a system meeting a carbon emissions target of 100gCO2/kWh in 2030. Moreover, a more ambitious carbon reduction target (50gCO2/kWh) would see a further increase in the value of flexibility (up to £7.8bn/year) as the system would need to accommodate more low-carbon generation.

Capturing the value of flexibility in the market design

Since the energy industry has been deregulated, the realization of the above system benefits of flexibility requires a suitable energy market design and regulatory structure that captures the multiple value streams of such flexibility, and aligns the cost savings / revenues of the flexibility up-takers in the different markets (energy, balancing, capacity) with the respective system benefits created. Significant efforts towards this direction have been recently observed in the UK setting, initiating major debates regarding the transition to a fundamentally new market design. However, there are still certain issues that need to be addressed.

The most fundamental drawback behind the current market design philosophy lies in the fact that it has been developed considering the characteristics of the system before the massive integration of new forms of renewable and low-carbon generation. As such, this design has mainly focused on the trading arrangements for energy as a basic commodity, while trading arrangements for flexibility and capacity services are still under development. However, the envisaged decarbonisation of the energy system will lead to a massive reduction of the energy production costs accompanied by a massive increase of the costs of balancing services and new capital investments. This implies that a fundamentally new market design is required to recognise the system value of distributed flexibility, developing new market segments across multiple timescales, ranging from capacity markets with a horizon of multiple years to balancing markets operating very close to real-time.

This report identifies and analyses the main barriers towards recognising these value streams of distributed flexibility in the market and provides relevant recommendations:

- ***Overcoming constraints on distributed market participants***: The limits imposed by market rules regarding the minimum size and the minimum temporal availability of participants in energy, balancing and capacity markets may prevent distributed forms of flexibility to access value streams in certain markets. Although the size constraint can be bypassed through the aggregation of multiple flexibility sources, independent aggregators in the UK need to rely on third parties to access the balancing mechanism as they do not have a defined role in the Balancing and Settlement Code (BSC), which discourages small scale aggregators from accessing value in the markets. Finally, the current market design sets certain restrictive constraints regarding the simultaneous participation in multiple market segments, although these segments remunerate different valuable services.

- ***Recognising the time-specific value of flexibility***: The largest proportion of balancing services is currently contracted by system operators with prices being determined based on their own cost projections and being fixed over a long temporal interval (months-ahead or even years-ahead). However, the economic value of flexibility services such as frequency response depends massively on system conditions (e.g. demand level, renewable output, system inertia) that change in much faster timescales. This inefficiency can result in a risk of over- or under-procurement of services and a lack of availability of flexibility resources for other services, with significant cost implications. Therefore, these services should be procured over shorter timeframes taking account of their mutual trade-off and thus more efficiently reflect the temporal variation in their value in the system. More dynamic price signals can potentially incentivise availability of flexibility during periods when it is most needed by the system.

- ***Recognising the time-coupling operational characteristics of DSR and energy storage in market design***: DSR and energy storage technologies exhibit distinct operational characteristics that are fundamentally different from the respective characteristics of traditional market players, such as fixed energy constraints, load recovery effects and storage losses. These complex, time-coupling operating properties couple the requirements for provision of balancing services across different timescales and therefore should be included in the market design. If these properties are neglected in energy and balancing market segments, it becomes obvious that the outcome of these markets may not be cost-reflective.

- ***Recognising the location-specific value of flexibility***: The locational element of energy, balancing and capacity services becomes increasingly important, since different areas and regions are characterised by significantly different generation / demand conditions and many parts of the transmission and distribution network become increasingly congested Therefore, a need emerges to consider capturing this location-specific value in new market arrangements, through the introduction of locational marginal pricing. Furthermore, the location-specific part of the Transmission Network Use of System (TNUoS) charges and the Distribution Network Use of System (DNUoS) needs to be enhanced in order to properly allocate network charges to parties responsible for incurring network reinforcements. This implies that the reinforcement deferral / avoidance benefits that can be brought by the uptake of distributed flexibility will be remunerated sufficiently through reduced network charges.

- ***Introducing efficient capacity remuneration mechanisms***: Although the most significant economic benefits of distributed flexibility are associated with avoided investments in new generation and network capacity, this value stream is not properly remunerated in the current market framework. Concerning generation capacity, although a Capacity Market was recently introduced in the UK, it was soon after suspended, as distributed technologies were not able to participate on a level playing field with traditional, large-scale generation technologies. At the network level, the potential capacity provision of new distributed flexibility technologies as well as their location-specific value is greatly neglected in existing network standards. With the emergence of cost effective non-built solutions, an update of these planning and operational standards is needed to establish a level playing field between traditional network infrastructure and emerging flexible technologies.

- ***Enhanced TSO-DNO coordination***: Although distributed DSR and energy storage technologies can offer valuable services both to the local DNO but also to the TSO, the coordination of these services entails potential conflicts between the TSO and the DNO. In the current framework, the TSO and the DNOs have limited coordination at both operation and planning activities, implying that such conflicts cannot be properly managed and balanced. This current “silo” approach for the operation and planning practices of the TSO and the DNOs should be replaced by a “holistic” approach which will enable stronger coordination between national and local objectives and requirements, maximising the economic value of distributed flexibility for the whole system. In order to achieve that, it will be critical to establish strong coordination and communication between distribution and transmission network operators and clearly define their future roles and responsibilities. Furthermore, an appropriate regulatory framework around the exchange of information and data between them should be established and proper economic incentives to support this communication should be designed.

Bidding structures

One of the key aspects of any electricity market design is the bidding structure, i.e. the format based on which market participants submit their techno-economic characteristics, preferences and requirements to the market clearing engine. The key challenge behind determining a suitable bidding structure lies in the fact that the physical operating characteristics of most market participants are complex, time-coupling and non-convex. Depending on how and to which extent the bidding structure encapsulates these complex characteristics, different bidding structures have been investigated in the literature and employed in actual markets, which can be broadly classified into three main categories:

- ***Simple bidding***: "Simple" or "one-part" bids usually consist of a set of pairs of (energy) quantity (offered in the case generators or requested in the case of consumers) and desired price. The market clearing process lies in building a supply and a demand curve considering the submitted simple bids and determining the market clearing outcome from their intersection. The main principle of this bidding structure is to keep the bidding and market clearing process simple and transparent by not allowing market participants to explicitly reveal their complex operating characteristics but rather forcing them to "internalise" these complex characteristics into "simple" bids, based on their expectations of how their assets may be scheduled by the clearing algorithm. However, the participants' expectations are often wrong and consequently the participants face the risk of infeasible or inefficient scheduling and / or the risk of not being able to recover all of their costs in the market. Since participants need to deal with these risks, they often artificially increase their submitted desired prices, leading to inefficient market outcomes with high costs. These drawbacks are nowadays widely recognized and prevent the practical implementation of simple bidding structures.

- ***Fully complex bidding***: The main principle of this bidding structure is to allow the market participants to explicitly reveal all their complex operating characteristics and factor these in the market clearing process, rendering the market operator responsible for satisfying the physical constraints of the market participants. In addition to price-quantity pairs, complex bids include a representation of the entire set of the participants' cost components and technical constraints. Unlike simple bidding, application of fully complex bidding ensures that the resulting schedules are physically feasible, respecting the participants' capabilities and limitations. Real-world electricity markets with fully complex bidding mechanisms include many markets in the USA (e.g. California, PJM, New York, MISO), and Europe (e.g. Greece, Poland, Ireland & Northern Ireland). When a fully complex bidding structure is adopted, the market clearing process involves the solution of a mixed-integer, least-cost, unit commitment problem. However, despite the recent advances in computational approaches for unit commitment problems, the performance of the market clearing algorithm deteriorates with an increase in the number of generation units and the size of the network, leading to poor scalability. Furthermore, this bidding structure requires all participants to submit all their techno-economic parameters to the market operator. Although this can be acceptable in wholesale electricity markets with a relatively small number generation-only participants, the participation of a vast number of distributed flexibility sources will entail communication and computation scalability problems and potentially privacy concerns by electricity consumers.

- ***Semi-complex bidding***: The main principle of this bidding structure is to mimic the actual operating characteristics of market participants, without however forcing the participants to explicitly reveal them, in order to address the privacy concerns discussed above. Such structures have been recently implemented in some European markets, such as the Central Western European (CWE) market, the Nord Pool Spot (NPS) day-ahead market and the Turkish market. In addition to simple price-quantity bids, these structures include various forms of combinatorial bids expressing "all-or-nothing" conditions, usually called "complex orders" or "block orders". The application of these complex orders requires the introduction of binary variables in the market clearing problem to capture their "all-or-nothing" properties. Furthermore, due to the inherent indivisibilities of the complex orders, inconsistencies between the cleared blocks and their clearing conditions (known as "paradoxically accepted / rejected blocks", or PABs and PRBs, respectively) may occur, which necessitate the employment of complex, branching algorithms for the market clearing process. Most European markets have historically adopted heuristic iterative approaches and empirically simplifying criteria in order to handle PABs and PRBs, and reach an acceptable market clearing solution.

Market power issues

Electricity markets are still characterized by a small number of large players who do not necessarily act as price takers. Players owning a large share of the market and / or strategically located in the network are able to manipulate the electricity prices and increase their profits beyond the competitive equilibrium levels, through strategic bidding. In other words, they do not reveal their actual operating characteristics in their bids to the market but rather misreport them to increase their economic surpluses. This effect is known as market power exercise and results in increased price levels as well as loss of social welfare.

Generation companies can generally exercise market power through two different strategies. The first one is known as economic withholding and lies in misreporting their operating costs, i.e. reporting in their offers to the market higher than their actual operating costs. The second one is known as physical withholding and lies in misreporting their generation capacity, i.e. offering less than their actual capacity to the market. Previous works have identified some general measures to mitigate such market power, such as a) promoting the separation of dominant companies in order to limit the market share of each company; b) encouraging the entry of new participants in order to foster competition; and c) imposing price caps and floors on participants.

Given that DSR and ES technologies have attained increasing interest in the context of the electricity system decarbonisation, there is an emerging need to investigate their role and impacts in imperfect electricity markets. This task involves two equally significant perspectives: the perspective of price-taking DSR / ES and the perspective of price-making DSR / ES.

Under the first perspective, DSR / ES owners are assumed to behave competitively and reveal their actual techno-economic characteristics to the market. The validity of this assumption is likely for independent, small-scale, distributed DSR and ES which cannot unilaterally affect the market outcome. Previous work on this area has demonstrated that price-taking DSR and ES can mitigate the exercise of market power by large generation companies.

Under the second perspective, DSR / ES owners are assumed to behave strategically and misreport their techno-economic characteristics to the market i.e. instead of mitigating large producers' market power they exercise themselves market power. The validity of this assumption is likely for large-scale DSR and ES or a number of smaller DSR and ES operated by the same market entity (e.g. an aggregator), which can affect the market outcome through their individual actions. In the case of DSR, market power can be exercised by misreporting their actual benefit curve, while in the case of ES, market power can be exercised by misreporting their actual power or energy capacity.

The above market power issues and mitigation measures have been analyzed by quantitative modeling approaches which can be broadly classified in two categories. The first one involves bi-level optimization models which can capture in a mathematically rigorous fashion the interaction between the strategic decision making of self-interested players (modeled in the upper level) and the competitive clearing of the electricity market (modeled in the lower level). The second one involves agent-based and reinforcement learning approaches where the market players (agents) gradually learn how to improve their strategies by utilizing experiences acquired from their repeated interactions with the market clearing process (environment). Although the bi-level optimization approaches exhibit higher mathematical rigorousness, they are less scalable to problems with large number of players and consideration of more physical system or participants' constraints. On the other hand, the employment of reinforcement learning approaches by market players may result to significant risks for the stability of the market, since they do not incorporate a closed-form representation of the economic and technical parameters of the system.

Towards decentralised market designs

Existing electricity markets follow centralised designs: all market participants submit their economical and technical characteristics to a central market clearing engine and the latter clears the market through the solution of a global optimization problem (usually social welfare maximization). In the electricity markets of the past, this approach was perfectly acceptable, as the number of the market participants was relatively small (basically including a few large generation companies and a few large suppliers). However, the envisaged participation of a vast number of distributed flexibility sources will render the communication and computation scalability of centralised designs at least questionable while consumers are likely to raise privacy concerns.

In view of these challenges, recent research work has focused on the development of alternative, decentralised market designs, which do not require full knowledge of the participants' characteristics by a central market operator. However, the crucial challenge behind these decentralised designs is to achieve feasibility and optimality for the market clearing outcome. Such designs can be broadly classified into two categories:

- ***Semi-decentralised designs***: This category includes price-based coordination architectures, involving a two-level iterative process. At the local level, individual participants determine their optimal responses to a set of given electricity prices by independently solving their economic surplus maximization problems; at the global level, the market operator updates these prices in order to drive participants' responses to the optimal market clearing solution. This type of designs is semi-decentralised, in the sense that it stills requires a central market operator to update the prices transmitted to the market participants, although this market operator does not have centralised knowledge of the participants' techno-economic characteristics. A key challenge of such price-based designs is associated with the notorious loss of diversity and response concentration effects, i.e. the participants' response is discontinuously concentrated at the lowest-priced or highest-priced periods. As a result, the market clearing outcome is highly inefficient or even infeasible. In order to address these effects alternative smart designs have been proposed, such as imposing flexibility restrictions, applying non-linear flexibility prices and randomizing prices transmitted to different market participants.

- ***Fully decentralised designs***: This category completely avoids the need for a central market operator, and the market clearing process is based solely on the bilateral exchange of messages between the different market participants. Such designs are based on novel distributed coordination approaches, including consensus algorithms and alternating direction method of multipliers (ADMM). In these approaches, the market participants exchange signals until they reach a consensus about certain global variables (e.g. the market clearing prices). Due to the absence of a central market operator, the challenges to achieve feasibility and optimality for the market clearing outcome are even more pronounced with respect to semi-decentralised approaches.

1. Context setting

1.1 Decarbonisation of energy systems

Energy systems across the world are currently undergoing fundamental changes, mainly driven by the continuously increasing levels of greenhouse gases emission in the atmosphere and the associated environmental and climate change concerns. Numerous governments have taken significant initiatives in response to such concerns. In the United Kingdom, the *2008 Climate Change Act* [1] set a legally binding target of 26% reduction in greenhouse gases emissions by 2026 (with respect to the 1990 baseline), extended to a further ambitious target of 80% reduction by 2050. More recently, in its advice to the UK Government on future carbon budgets, the Committee on Climate Change (CCC) has emphasised the importance of decarbonising the power sector and recommended that the aim should be to reduce the carbon intensity of power generation from the current levels of around 350 gCO2/kWh to around 100 gCO2/kWh in 2030 and potentially 25g CO2/kWh in 2050 [2]. Apart from the issue of climate change, growing energy security concerns emerge over the dependency of energy systems on fossil fuels exhibiting a continuously reducing availability and a subsequent increase of their prices.

In the context of addressing the above environmental and energy security concerns, energy systems are facing the challenge of decarbonisation. At the generation side, this decarbonisation is already under way through the wide deployment of renewable and other low-carbon (such as nuclear) generation sources. The European Commission has put forward a legally binding target for renewable energy sources to cover 20% of the total energy consumption in the European Union by 2020 [3], extended to a further target of 27% by 2030 [4]. However, the majority of these sources -especially wind and solar generation which constitute the dominant renewable energy technologies in the UK [5]- are inherently characterized by high variability and limited predictability and controllability. Their power output is not only extremely variable, but is also zero during periods of low wind speed or no sunshine. Furthermore, increased shares of renewables (i.e. inverter based power generation) in the capacity mix reduce the system inertia which is provided by the stored kinetic energy of the rotating mass of the power generators' turbines. With this reduction in system inertia, any imbalance between supply and demand will change system frequency more rapidly than today, challenging the stability of the system. Furthermore nuclear generation is highly inflexible, implying that it cannot contribute to the balancing burden of the system.

At the demand side, significant decarbonisation of the heat and transport sectors is expected beyond 2030. Traditional technologies for the satisfaction of heating and transportation consumers' requirements (gas / oil fired technologies for heating and internal combustion engines for transportation) are based on the intense consumption of fossil fuels and the emission of a significant portion of the total greenhouse emissions [6]-[9]. In combination with the ongoing and future decarbonisation of electricity generation systems, strong motives arise for the electrification of these technologies. Recent technological developments in the automotive and heating sectors have techno-economically enabled this transition with the production and efficient operation of *electric vehicles* (EV) [7], [9] and *electric heat pumps* (EHP) [7] respectively. Nevertheless, due to the natural energy intensity of heating and transportation loads, the environmental and energy security potential of this transition is accompanied by the introduction of a considerable amount of new demand in electrical power systems. Going further, the electrification of heat and transport sectors will lead to disproportionately larger demand peaks than the increase in the total electrical energy consumption, due to the temporal patterns of users' heating and driving requirements [10].

In order to understand the challenges this decarbonisation of energy generation and demand creates for electrical power systems, we need to keep in mind certain operation and planning properties of current systems. At the short-term operation timescale, given that demand is currently largely treated as an inflexible, uncontrollable load, the required flexibility for balancing the system and offering the required ancillary services is provided solely by conventional dispatchable generators (mainly gas generators).

In a future with an increased penetration of renewable and nuclear generation, these conventional generation units will be producing much less energy, as absorption of the low-cost and CO2-free production of renewable and nuclear generators will be prioritised in the merit order. However, given that renewable generation is variable and intermittent and nuclear generation is highly inflexible, the conventional generators need to remain synchronised in the system and operate part-loaded as a back-up energy source (e.g. operating in periods of low wind speed or low sunshine) and flexibility provider (since renewable and nuclear generators not only have very limited capabilities to provide system balancing services, but they are also making system balancing more challenging). This under-utilisation of conventional generation assets implies that the cost efficiency of their operation will reduce. Furthermore, their cost efficiency will be aggravated by the increase of their start-up and shut-down cycles, driven by the system variability and power ramping requirements.

Furthermore, a sufficient level of frequency response is needed to deal with sudden loss of supply to the system (e.g. as a result of a failure of a large generator / interconnector or a rapid change in demand or renewable generation) in order to keep the system frequency within its statutory limits. To date, the frequency response service can only be provided by synchronised conventional plants which need to operate part-loaded and produce at least at the minimum stable generation level (MSG). This reduces the ability of the system to absorb electricity production from renewables or other low-carbon technologies. This means that due to balancing challenges, renewable generation assets with high capital costs are also under-utilised and thus may not achieve their CO2 emissions reduction potential.

Moreover, the large-scale connection of renewable generation to transmission and distribution grids creates certain network challenges, such as thermal congestion, increased voltage levels and increased short-circuit currents, which threaten the security of these grids

At the long-term planning timescale, given that demand is again treated as an inflexible load, the current paradigm lies in predicting this demand and building sufficient generation and network capacity (given certain security margins) to cover it. The disproportional increase in demand peaks with respect to the increase in overall energy consumption, induced by the envisaged electrification of heat and transport sectors, means that a significant amount of new generation and network capacity needs to be built in the coming years, and this capacity will be significantly under-utilised as it will be used only to cover the increased demand peaks. Furthermore, the connection of a large number of controllable loads in combination with their response to energy price signals and network charges often leads to synchronisation effects which further aggravate the demand peaks.

Given the above factors, under the current Business-as-Usual (BaU) operation and planning paradigm, the utilization of generation and network assets will be significantly reduced, while the total system costs will be dramatically increased, especially beyond 2030 where the electrification of heat and transport will require capital-intensive investments.

1.2 Need for system flexibility

Given the above fundamental techno-economic challenges associated with the decarbonisation of energy systems, a clear need emerges for enhancing their flexibility through the efficient integration of new technologies. As thoroughly discussed in [2], such technologies include:

- *Demand Side Response (DSR)*: DSR schemes can re-distribute the electricity consumption across time without significantly compromising the service quality delivered to consumers.

- *Energy storage*: Energy storage technologies have the ability to act as both demand and generation sources and flexibly schedule their input / output across multiple timescales.

- *Flexible generation*: Advances in conventional generation technologies are allowing them to provide enhanced flexibility to the system. This is due to their ability to start more quickly, operate at lower levels of power output (minimum stable generation), and achieve faster changes in output.

- *Cross-border interconnection*: Interconnectors to other systems which enable large-scale sharing of energy, ancillary service and back-up resources.

The Cornwall Local Energy Market (LEM) project focuses specifically on local, distributed forms of flexibility, including distributed DSR and distributed energy storage.

Suitable coordination of such distributed forms of flexibility has the potential to support system balancing in a future with an increased penetration of renewable generation and therefore to reduce the curtailment of renewable generation and the efficiency losses of conventional generation, as well as limit peak demand levels and therefore avoid capital intensive investments in under-utilized generation and network assets. More specifically, as discussed in [2], the potential value streams of such flexibility technologies are:

- Avoidance of energy curtailment from low-carbon generation sources by increasing demand during periods of abundant renewable generation,

- Efficient provision of operating reserve and response services, reducing the operating costs associated with keeping under-utilised conventional generation in the system,

- Potential savings in generation capacity investments, including a reduced need for low-carbon capacity (reductions in energy curtailment will result in increased utilisation hence lower capacity of renewable and nuclear generation to meet the decarbonisation targets), a reduced need for peaking plant capacity (as a result of demand peak reductions), and a reduced need for flexible, back-up capacity (as such generation capacity can be replaced by these flexible technologies in the provision of balancing and ancillary services),

- Deferral or avoidance of the network reinforcements / expansions, by deploying flexibility to manage network constraints.

In other words, intelligent coordination of such flexibility sources in both operation and planning timescales can reverse the trend of asset utilization reduction and enable a more cost-effective transition to the low-carbon future. According to the studies undertaken in [2], the size of the above system wide benefits in the UK is very significant - between £3.2bn and £4.7bn per year in a system meeting a carbon emissions target of 100gCO2/kWh in 2030. Moreover, a more ambitious carbon reduction target (50gCO2/kWh) would see a further increase in the value of flexibility (up to £7.8bn/year) as the system would need to accommodate more low-carbon generation (Figure 1). It can be observed that the most significant value stream of flexible technologies, especially as we move towards more ambitious carbon targets, is the avoidance of investments in low-carbon generation capacity.

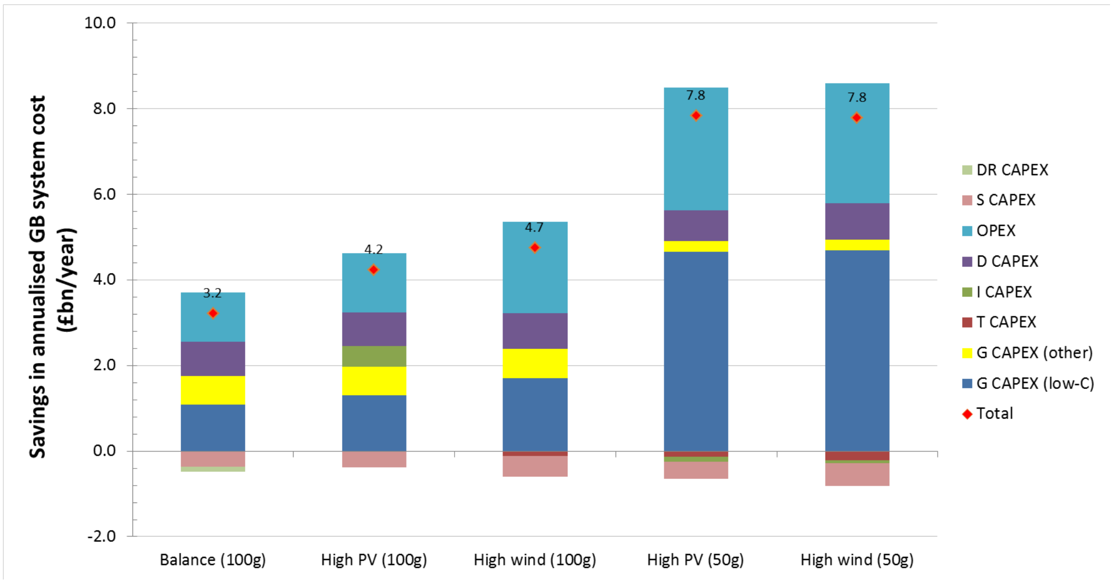

Figure 1. System-level benefits of flexible technologies [2]

2. Capturing the value of flexibility in the market design

Major efforts towards the deregulation of the energy industry have been carried out in the last three decades, involving the unbundling of vertically integrated utilities, the introduction of competition in the generation and supply sectors of the industry and the open third-party access to the electricity network.

In this deregulated environment, the realisation of the system benefits of flexibility resources discussed in Section 1.2 requires a suitable energy market design and regulatory structure that captures the multiple value streams of such flexibility, and aligns the cost savings / revenues of the flexibility up-takers in the different markets (energy, balancing, capacity) with the respective system benefits created.

Significant efforts towards this direction have been recently observed in the UK setting, initiating major debates regarding the transition to a fundamentally new market design. However, we believe there are still certain issues that need to be addressed.

The most fundamental drawback behind the current market design philosophy -which is associated with many of the specific limitations that will be discussed in the following sections- lies in the fact that it has been developed considering the characteristics of the system before the massive integration of new forms of renewable and low-carbon generation.

As such, this design has mainly focused on the trading arrangements for energy as a basic commodity, while trading arrangements for flexibility and capacity services are still under development.

However, as discussed in Section 1.1, the envisaged decarbonisation of the energy system will lead to a massive reduction of the energy production costs (due to the low or zero production costs of renewables and nuclear generation) accompanied by a massive increase of the costs of balancing services (due to the inherent variability and intermittency of renewable generation and the inflexibility of nuclear generation) and new investments (due to the need for new generation and network assets to support system balancing and the increasing demand peaks) [2]. This implies that a fundamentally new market design is required to achieve the UK decarbonisation objectives in a cost efficient manner, making optimal use of the flexibility provided by new technologies such as distributed DSR and energy storage.

This means that under a suitably designed market and regulatory framework, distributed flexibility up-takers should be able to simultaneously provide multiple different services and thus access multiple value streams. Based on the discussion in Section 1.2, these value streams include:

- *Energy cost savings*: This value stream is associated with the ability to redistribute demand towards periods of high renewable generation and low demand, and potentially inject energy (through storage capabilities) at periods with low renewable generation and high demand.

- *Revenues from provision of balancing services*: This value stream is associated with the ability to provide various types of reserve and frequency response services to the electricity system, and therefore assist the latter in dealing with the extensive variability, unpredictability and lack of controllability of renewable generation. These services are used by the System Operator to ensure that supply meets demand at all times and that the system frequency remains within statutory limits around the target level of 50Hz. More specifically, DSR and energy storage can offer the capability to either increase or decrease demand / supply with respect to the amount they have procured in the electricity energy market, in case an imbalance occurs between the total generation and total demand in the system. The main balancing services in the UK market include [2]: a) *Short Term Operating Reserve (STOR)*: spare generation capacity (or demand reduction capability) on stand-by during certain hours of the day (typically during periods of rapid change in demand or generator loading) for dealing with actual demand being greater than forecast demand and/or plant unavailability; b) *Fast Reserve*: rapid and reliable delivery of active power through an increased output from generation or demand reduction, following receipt of an electronic dispatch instruction from the TSO; c) *Frequency Response*: the automatic provision of increased/reduced generation or demand reduction/increase in response to a drop/increase in system frequency; it can be delivered through either Dynamic Response (a continuous service used to manage second by second changes on the system) or Static Response (a discrete service usually triggered by a defined frequency deviation).

- *Revenues from provision of generation and network capacity services*: This value stream is associated with the ability of distributed flexibility to defer or avoid reinforcements of the distribution / transmission network and investments in new low-carbon and peaking generation capacity, by reducing demand at peak periods.

This implies that a fundamentally new market design is required to recognise the system value of distributed flexibility, developing new market segments across multiple timescales, ranging from capacity markets with a horizon of multiple years to balancing markets operating very close to real-time.

The next sections present some more specific market design challenges.

2.1 Overcoming constraints on distributed market participants

Energy, balancing and capacity market designs both in the UK and beyond set certain constraints and limits regarding the allowable characteristics of market participants. In general, these include constraints regarding the minimum size and the minimum temporal availability of the participants.

Unfortunately, in most cases the imposed limits are excessively strict and non-transparent, unduly restricting distributed forms of flexibility to access value streams in certain markets. This is because these forms of flexibility are naturally associated with small sizes and cannot guarantee very high levels of availability (such as the ones usually guaranteed by large generators) since they need to satisfy consumers' requirements that are usually variable and not perfectly predictable.

Although the size constraint can be bypassed in some cases through the aggregation of multiple small flexibility sources, independent aggregators in the UK need to rely on third parties to have access to the balancing mechanism as they do not have a defined role in the Balancing and Settlement Code (BSC). This involves administrative costs and sharing of some revenues with third parties which discourages small scale aggregators from accessing value in the energy and balancing markets.

Beyond the minimum size and temporal availability constraints, the UK market design sets certain restrictive constraints regarding the simultaneous participation in multiple market segments. For example, EFR providers and holders of long-term STOR contracts were ineligible for participation in the Capacity Market. This rule is not aligned with the principles of cost-reflectivity as balancing and capacity markets are supposed to remunerate different system services with different value streams.

2.2 Recognising the time-specific value of flexibility

The largest proportion of balancing services (primary, secondary and tertiary reserves) in the UK and beyond is currently contracted by system operators with prices being determined based on their own cost projections and being fixed over a long temporal interval (months-ahead or even years-ahead). However, the economic value of flexibility services such as frequency response depends massively on system conditions (e.g. demand level, renewable output, system inertia) that change in much faster timescales.

For example, as demonstrated in [2], the frequency response requirements of the system increase significantly when the net demand is low e.g. when a low demand condition coincides with high output from non-dispatchable renewable generators, due to the lack of sufficient inertia. On the other hand, the system requires less frequency response during high demand conditions coinciding with low output from non-dispatchable renewable generators, considering there are many synchronised plants with mechanic inertia in the system.

In other words, the need and value of flexibility is time dependent; it varies across different seasons as well as across different times of the day, driven by system conditions. Under the envisaged growth in intermittent renewable and inflexible nuclear generation, variation in supply is becoming even more pronounced. At the same, the nature of demand variability is changing as new sources of demand (e.g. electric vehicles) bring additional variability in demand-supply balance from the demand side.

In the UK, flexibility services such as the frequency response are procured through a monthly tender based on the demand for this service which is assessed up to several weeks ahead of real time. In the future with growing needs for flexibility, more dynamic price signals (i.e. time dependent cost of energy and value of flexibility) can potentially incentivise availability of distributed flexibility during periods when it is most needed by the system. Ofgem has recently announced its plans and a timetable on moving to mandated half-hourly settlement to sharpen short-term signals in order to better reflect the cost to the system and enable new distributed technologies to realise more value and suppliers to develop innovative dynamic retail offerings [11].

2.3 Recognising the time-coupling operational characteristics of DSR and energy storage in market design

DSR and energy storage exhibit distinct operational characteristics which are fundamentally different from the respective characteristics of traditional market players such as large generators. These include time-coupling properties, such as fixed energy constraints, load recovery effects and energy storage losses. For example, although DSR and storage can modify the temporal profile of the electricity demand across shorter horizons, the overall level of electrical energy cannot significantly change (reduce or increase) within large horizons, as consumers need certain (generally fixed) levels of energy to satisfy their service requirements. In other words, their overall consumption during certain temporal horizons (e.g. a day) cannot significantly change and needs to remain relatively fixed, but the specific time periods (e.g. hours) that energy is acquired within such horizons can be flexibly modulated. This implies that load reduction during certain periods is accompanied by a load recovery effect during preceding or succeeding periods. Finally, the deployment of implicit or explicit storage is always accompanied by certain energy losses in the storage means which need to be accounted for.

These complex, time-coupling operating properties couple the requirements for provision of balancing services across different timescales and therefore should be included in the market design. In other words, the provision of flexibility at a particular timeframe creates additional demand for flexibility at other times due to above time-coupling effects. If these properties are neglected in energy and balancing market segments, it becomes obvious that the outcome of these markets will not be cost-reflective. A relevant example is presented in [2]. If DSR is used at a particular time to provide frequency response, the need for secondary reserve may increase due to the effects of load recovery. If these effects are ignored in the procurement mechanism of balancing services, the value of flexibility can be overestimated.

Furthermore, the procurement of different balancing services should account for interactions or trade-offs between services. Under the current arrangements in the UK, the volumes of various operating reserve products are procured separately and do not comprehensively account for the interactions between the procured products. For example, as both frequency response and enhanced frequency response share the same goal to limit the system frequency nadir above the standard, these two services should, in fact, be procured together based on their mutual interactions to minimise their overall cost. With the envisaged massive integration of renewable generation and the subsequent rise in the amount of balancing requirements, the optimisation of the portfolio of various flexibility services required by the system operator becomes more important.

2.4 Recognising the location-specific value of flexibility

Beyond the temporal element discussed above, recognising the locational element of energy, balancing and capacity services becomes increasingly important as we move towards the low-carbon energy future. This is because different areas and regions are characterised by significantly different generation / demand conditions (especially due to the location-specific availability of wind and solar resources) and many parts of the transmission and distribution network become increasingly congested.

Therefore, a need emerges to consider capturing this location-specific value in new market arrangements, through the introduction of locational marginal pricing. This can take different forms, from zonal to nodal pricing, and requires according modifications in the balancing and capacity market designs.

Furthermore, the location-specific part of the current Transmission Network Use of System (TNUoS) charges and the Distribution Network Use of System (DNUoS) constitutes a very small proportion (around 10%) of the overall charges, leaving a large amount to be recovered through the residual (socialised) charges [12]-[14]. As a consequence network charges do not properly allocate costs to parties responsible for incurring network reinforcement nor provides locational incentives for generation, DSR or storage. This implies that the reinforcement deferral / avoidance benefits that can be brought by the uptake of distributed flexibility are not currently remunerated sufficiently through reduced network charges. Therefore, network charging needs to become more cost-reflective, capturing the locational impacts of different market participants.

2.5 Introducing efficient capacity remuneration mechanisms

As discussed in Section 1.2, one of the most significant economic benefits of distributed flexibility in the low-carbon future lies in avoiding investments in new generation (including low-carbon and peaking) and network capacity. However, a crucial limitation of the current UK and European market framework is that this value stream of distributed flexibility is not properly remunerated.

Concerning the remuneration of peaking generation capacity contributions, a positive first step has been recently taken in the UK with the introduction of the Capacity Market, which aims at delivering generation adequacy [2]. In this market, capacity contracts are allocated to providers through auctions intended to secure a capacity requirement in order to meet the reliability standard set by the UK government and provide an insurance policy against the possibility of future blackouts. However, the operation of this market has been recently suspended. One of the reasons for this development was the fact that distributed technologies were not able to participate on an equal footing with traditional, large-scale generation technologies. This is because the contract length offered to DSR was smaller than the one offered to large generators and the minimum size constraints imposed on the potential providers were very restrictive and the possibility and terms of demand aggregators' participation had not been fully clarified. This is especially relevant as the international experience, particularly in the USA, clearly demonstrated significant and successful participation of DSR in the capacity markets, which led to the reduction in the overall costs. There is also very significant evidence that DSR performed reliably.

Beyond the peaking generation capacity contributions, distributed flexibility offers significant benefits in reducing the requirements for low-carbon (including renewables and nuclear) generation capacity. In this aspect, the market and regulatory challenges are even more significant, given that no suitable mechanisms for the remuneration of this value stream exist neither in the UK nor beyond. We believe that such mechanisms should be urgently developed, either by allowing new flexible technologies to access revenues associated with Contracts for Differences (CfD) offered to renewable generators and/or by linking the capacity market with the low-carbon agenda (setting specific rules on the types of capacity rewarded in the capacity market).

At the network level, the potential capacity provision of new distributed flexibility technologies as well as their location-specific value is greatly neglected in existing network standards. Existing planning and operational standards for both networks and generation systems were primarily developed around asset-based solutions and did not incorporate alternative solutions to meeting system operational requirements. With the emergence of cost effective non-built solutions, an update of these planning and operational standards is needed to establish a level playing field between traditional network infrastructure and emerging flexible technologies.

For example, in order to meet a rise in demand in a given distribution network, conventional network planning standards (e.g. involving N-1 or N-2 security levels) would typically trigger the need to build an additional transformer and / or line. However, depending on the characteristics of demand in the area e.g. if peak demand turns up for a limited time duration each year, the flexibility of DSR and energy storage can be used to reduce demand during these peak periods, relieving the electricity network stress and subsequently substituting the need for network reinforcement.

The network companies have recently initiated an effort to carry out a thorough review of Engineering Recommendation ER P2 which has acted as the foundation stone for cost effective planning of future distribution networks, which has been supported by Ofgem [15].

2.6 Enhanced TSO-DNO coordination

Distributed DSR and energy storage resources are naturally connected to the local distribution network level. In this setting, as discussed in Section 1.2, they can offer valuable services both to the local distribution network operator (DNO) -such as avoiding network reinforcements through reduction of electricity demand during peak periods, reduction of network losses, and potential contribution to voltage management- but also to the Transmission System Operator (TSO) -such as higher utilisation of renewable generation, provision of balancing services such as reserves and frequency response, and contribution to generation adequacy-.

However, the coordination of these services entails potential conflicts between the TSO and the DNO. For example, periods of abundant wind generation (periods of high wind speed) at the national system level may coincide with periods of local peak demand at the distribution level. In such a case and without prior coordination between the TSO and the DNO, DSR and energy storage will receive a signal from the national system level to increase their electricity demand in order to absorb the abundant wind generation (e.g. through reduced electricity energy prices) but they will also receive a signal from the local DNO to reduce their electricity demand in order to avoid overloading the distribution network (e.g. through increased network changes).

Unfortunately, in the current UK framework, the TSO and the DNOs have limited coordination at both operation and planning activities, implying that conflicts such as the one discussed above cannot be properly managed and balanced. This current "silo" approach for the operation and planning practices of the TSO and the DNOs should be replaced by a "holistic" approach which will enable stronger coordination between national and local objectives and requirements, maximising the economic value of distributed flexibility for the whole system.

In this "holistic" operation and design framework, the TSO and DNOs will be optimising the contribution of new distributed flexibility resources in a coordinated fashion. This will enable to maximise the whole-system benefits by managing the synergies and conflicts between local and national level objectives (e.g. maximising the value of combined benefits delivered through energy arbitrage, providing support to local and national network infrastructure, delivering various balancing services to optimise system operation, while reducing the investment in conventional and low carbon generation). Previous analysis [2], [16]-[17] demonstrates that this holistic approach may result in about 30% and 100% additional cost savings in the development and operation of the system with respect to a transmission-centric and a distribution-centric approach, respectively (Figure 2).

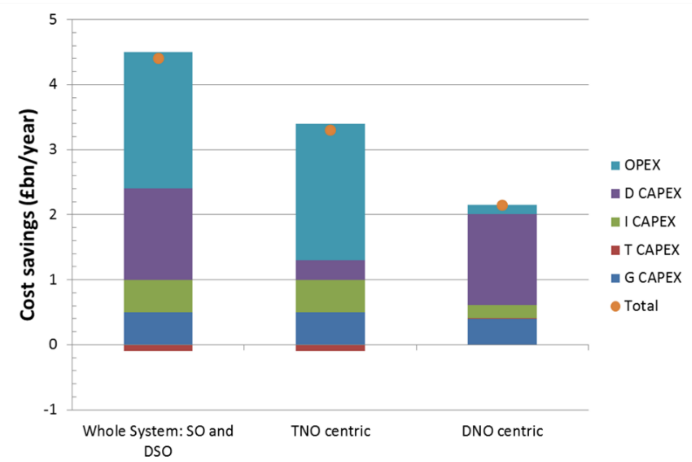

Figure 2. Potential benefits of TS0-DNO coordination [2]

However, in order to realise these whole-system benefits, it will be critical to establish strong coordination and communication between distribution and transmission network operators and clearly define their future roles and responsibilities. Furthermore, an appropriate regulatory framework around the exchange of information and data between them should be established and proper economic incentives to support this communication should be designed.

Some recent activities have attempted to clarify the future roles and responsibilities of system operators. Ofgem and BEIS have recently proposed alternative models for the future roles of system operators (at both transmission and distribution levels) [18]. Ofgem has also proposed several changes in the TSO's current role with the aim of creating an independent system operator (SO) where its role will be separated from the remaining functions of the National Grid [19]. Furthermore, the Transmission and Distribution Interface Steering Group of Energy Network Association's (ENA) also aims at providing strategic directions identifying potential issues around the coordination between transmission and distribution levels [20]. The group was formed of commercial and regulatory as well as technical representatives from DNOs, transmission companies, The Department of Energy & Climate Change (DECC) and Ofgem.

3. Bidding structures in electricity markets

One of the key aspects of any electricity market design is the bidding structure, i.e. the format based on which market participants submit their techno-economic characteristics, preferences and requirements to the market clearing engine which later uses this information to determine the schedule of the market participants and the prices based on which transactions will take place.

The key challenge behind determining a suitable bidding structure lies in the fact that the physical operating characteristics of most market participants are complex, time-coupling and non-convex; therefore, what needs to be decided is how and to which extent the bidding structure will encapsulate these characteristics. At the generation side, these include complex cost components and constraints that are associated with their unit commitment, such as no-load, start-up and shut-down costs, minimum stable generation limits, ramp rates and minimum-up / down time constraints. On the other hand, new market participants including flexible demand and energy storage participants exhibit similar complex characteristics such as fixed energy constraints, load recovery effects, fixed operating cycles with discrete power levels etc.

Depending on how and to which extent the bidding structure encapsulates these complex characteristics, different bidding structures have been investigated in the literature and employed in actual markets, which can be broadly classified into three main categories, discussed in the following sections. It should be stressed that most of the relevant work presented in these sections focuses on bidding structures for central, wholesale electricity markets; however, we believe that the following discussion and insights are relevant to new, distributed local markets such as the one explored in the Cornwall LEM project.

3.1 Simple bidding

The first type of bidding structures is known as "simple bidding" or "one-part bidding". As the name indicates, its main principle is to keep the bidding structure (and subsequently the market clearing process) simple and transparent by not allowing market participants to explicitly reveal their complex operating characteristics but rather forcing them to "internalise" these complex characteristics into "simple" bids.

"Simple" or "one-part" bids usually consist of a set of pairs of (energy) quantity (offered in the case generators or requested in the case of consumers) and desired price [21]. The temporal resolution and horizon to which these pairs refer depend on the specific market design, but in most wholesale markets the temporal resolution is hourly or half-hourly and the horizon varies between one day and a few hours ahead. The market design also prescribes how many quantity-price pairs each participant is allowed to include in their bids (usually between one and ten).

When a simple bidding structure is adopted, the market clearing process works as follows: for each time period (hour or half-hour depending on the adopted temporal resolution), a supply curve is built up considering the selling bids (from the generators) for that period ordered by increasing prices, and a demand curve is built up considering the buying bids (from the consumers) for that period ordered by decreasing prices. The intersection of the supply and demand curves determines the selling and buying bids that are accepted and the market price obtained as the price of the last accepted selling bid. Note that the market clearing is performed independently for each trading period, and it does not take into account any time-coupling constraints that could link the bids across different periods [22]-[23].

As mentioned before, application of this bidding structure implies that market participants need to "internalise" complex, time-coupling cost components and constraints into their "simple" price-quantity bids, based on their expectations of how their assets may be scheduled by the clearing algorithm [23]-[24]. Although this process simplifies the market clearing algorithm for the market operators, the participants' expectations are often wrong and consequently the participants face the risk of infeasible or inefficient scheduling and / or the risk of not being able to recover all of their costs in the market [25]. Since participants need to deal with these risks, they often artificially increase their submitted desired prices, leading to inefficient market outcomes with high costs [26].

The original motivation behind "simple" bidding structures was to simplify the market clearing algorithm and establish a single market clearing price without additional payments to participants for non-convex costs (e.g. no-load, start-up and shut-down costs), which were to be factored into the simple price-quantity bids [27]. However, in practice, this bidding format does not result in short-term efficiency, because the market operator is not allowed to optimize the market outcome based on the participants' actual characteristics, resulting in schedules that are not generally consistent with the participants' physical capabilities. Therefore, although simple bids provide a very high degree of transparency and simplicity, market clearing with simple bidding fails in guaranteeing feasibility [22]. These drawbacks are nowadays widely recognized and prevent the practical implementation of simple bidding structures. Nevertheless, some market designs such as Italy's [28] or the former California Power Exchange [29] are very close to this simple bidding model.

3.2 Fully complex bidding

On the other of the bidding structures spectrum, we find "fully complex bidding" or "multi-part bidding". The main principle of this bidding type is to allow the market participants to explicitly reveal all their complex operating characteristics and factor these in the market clearing process, rendering the market operator responsible for satisfying the physical constraints of the market participants.

In addition to price-quantity pairs, complex bids include a representation of the entire set of the participants' cost components and technical constraints. In wholesale electricity markets adopting fully complex bidding, these include the complex characteristics of the generation side, including no-load, start-up and shut-down costs, minimum stable generation limits, ramp rates and minimum-up / down time constraints [30]-[34]. Real-world electricity markets with fully complex bidding mechanisms include many markets in the USA (e.g. California, PJM, New York, MISO) [35]-[38], and Europe (e.g. Greece, Poland, Ireland & Northern Ireland) [30], [39].

When a fully complex bidding structure is adopted, the market clearing process involves the solution of a mixed-integer, least-cost, unit commitment problem [22]. Therefore, the market clearing algorithm explicitly accounts for the participants' techno-economic characteristics and thus the market operator becomes responsible for satisfying the physical constraints of the market participants. Over the past decade, the complexity of this unit commitment problem has been enhanced due to the need to account for network and security constraints, renewable generation, storage and DSR. The associated computational challenges have been addressed through the development of advanced unit commitment approaches [40]-[41].

Unlike simple bidding, application of fully complex bidding ensures that the resulting schedules are physically feasible, respecting the participants' capabilities and limitations [42]. Therefore, participants can submit their actual operating parameters without the risks associated with internalisation based on expectations, and the market outcome is more efficient [40].

However, despite the recent advances in computational approaches for unit commitment problems, the performance of the market clearing algorithm deteriorates with an increase in the number of generation units (because the number of binary commitment variables grows exponentially) and the size of the network, leading to poor scalability [41], [43]-[44]. Furthermore, this bidding structure requires all participants to submit all their techno-economic parameters to the market operator. Although this can be acceptable in wholesale electricity markets with a relatively small number generation-only participants, the participation of a vast number of distributed flexibility sources (such as small-scale DSR and energy storage) will entail communication and computation scalability problems and potentially privacy concerns by electricity consumers, who are not generally willing to disclose private information, such as habits, preferences and load assets' properties, during the bidding process [45]. Finally, many of the operating parameters of such distributed flexibility sources are highly uncertain due to lack of predictability of users' preferences and the dependence of their operating parameters on uncertain factors (e.g. weather). This may require the introduction of probabilistic bidding structures in the future.

3.3 Semi-complex bidding

The last type of bidding structures lies in between simple and fully complex structures. The main principle behind these intermediate structures is to mimic the actual operating characteristics of market participants, without however forcing the participants to explicitly reveal them, in order to address the privacy concerns discussed above and allow new types of players (such as DSR and energy storage) to participate in the market.

Such structures have been recently implemented in some European markets, such as the Central Western European (CWE) market [46]-[47], the Nord Pool Spot (NPS) day-ahead market [48] and the Turkish market [49]. In addition to simple price-quantity bids, these structures include various forms of combinatorial bids expressing "all-or-nothing" conditions, usually called "complex orders" or "block orders", which include:

User-defined block offers/bids:

A user-defined block offer/bid consists of a fixed price limit (for selling or purchasing energy, respectively) and a fixed volume for a user-defined number of consecutive hours (block periods). Block offers/bids are "all-or-nothing" orders, meaning that they are accepted or rejected in their entirety, depending on the average hourly market clearing price along the block periods. Block offers are extremely helpful to portfolio managers with production assets since they can spread out in many hours their units' start-up and shut-down costs.

Fixed block offers/bids:

They are similar to the user-defined block offers/bids, except that the block periods are pre-defined (by the market operator) and fixed. The definition of these block periods usually follows the temporal variation of the system load curve (peak, off-peak) or it may follow a simple daily period slicing method.

Linked block offers/bids:

The clearing of these orders is conditional and related to the clearing of their associated block order (called "parent block"). There are two possible relations between the "parent" and "child" block, (a) a tower-like parental relationship, and (b) a parallel parental relationship in each prioritization level. The purpose of linked block offers is to help mainly producers to schedule efficiently their generating units above their technical minimum.

Profile block offers/bids:

A profile block offer/bid is similar to the simple block offer/bid, with the difference that it involves an energy profile during the subsequent dispatch periods instead of a fixed energy quantity. The clearing of a profile block is based on the comparison between its offer price and the weighted average market clearing price for the specified set of dispatch periods. The purpose of profile block offers/bids is to help mainly producers to schedule efficiently (using a certain production profile) their generating units above their technical minimum.

Exclusive block orders:

An "exclusive" group is a set of block orders for which the sum of the acceptance ratios cannot exceed 1. In the particular case of blocks that have a minimum acceptance ratio of 1, this means that at most one of the blocks of the exclusive group can be accepted. Between the different valid combinations of accepted blocks, the algorithm chooses the one which maximizes the optimization criterion. The purpose of exclusive block orders is to help mainly producers to flexibly schedule their generating units within the daily period.

Flexibly hourly orders:

A flexible "hourly" order is a block order with a fixed price limit, a fixed volume, minimum acceptance ratio of 1, and with duration of 1 hour. The specific hour is not defined by the participant but will be determined by the market clearing algorithm (hence the name "flexible").

Convertible block offers:

They are similar to block offers, except that they are eligible for conversion to hourly offers when (a) not cleared as a block at the market clearing problem solution, and (b) the maximum clearing price has been reached in at least one hour in the specified block period. The market participant indicates for each block offer whether it is convertible, and in that case states the hourly price in the event of conversion. These orders were tradable in Nord Pool Spot, but nowadays they have been abandoned since they were not used enough by the market participants.

The application of these complex orders requires the introduction of binary variables in the market clearing problem to capture their “all-or-nothing” properties. Furthermore, due to the inherent indivisibilities of the complex orders, inconsistencies between the cleared blocks and their clearing conditions (known as “paradoxically accepted / rejected blocks”, or PABs and PRBs, respectively) [50] may occur, which necessitate the employment of complex, branching algorithms for the market clearing process. Most European markets have historically adopted heuristic iterative approaches and empirically simplifying criteria in order to handle PABs and PRBs, and reach an acceptable market clearing solution [51]-[56].

The vision to integrate the European electricity markets involves the market coupling among interconnected power systems and the enhancement of market competition forces. This process is facilitated by the adoption of a common clearing algorithm among European markets, entitled EUPHEMIA (Pan-European Hybrid Electricity Market Integration Algorithm) [57], which however still exhibits certain limitations [58].

4. Market power issues

The main motivation behind the recent deregulation of the electricity industry involved the unbundling of vertically integrated utilities and the introduction of competition in the generation and supply sectors of the industry in order to reduce the total system costs. However, generation and supply markets are still characterized by a small number of large players. Therefore, these markets are better described in terms of imperfect instead of perfect competition. In this setting, market participants do not necessarily act as price takers. Producers or suppliers owning a large share of the market and / or strategically located in the network are able to manipulate the electricity prices and increase their profits beyond the competitive equilibrium levels, through strategic bidding. In other words, they do not reveal their actual operating characteristics in their bids to the market but rather misreport them to increase their economic surpluses. This effect is known as market power exercise and results in increased price levels as well as loss of social welfare [59]-[60].

Most of the existing research and practical experience around market power issues has focused on the strategic behaviour of large generation companies. However, the recent introduction of DSR and energy storage in electricity markets has driven the investigation of similar issues associated with the strategic behaviour of these new participants, in cases where their size is significant or in cases where they participate in small-scale, local markets, such as the one explored by the Cornwall LEM project.

Previous works [59], [61]-[62] have identified some general measures to mitigate participants’ market power, such as a) promoting the separation of dominant companies in order to limit the market share of each company; b) encouraging the entry of new participants in order to foster competition; and c) imposing price caps and floors on participants.

A large number of research papers have proposed and developed quantitative modeling approaches to investigate market power issues and mitigation measures. These approaches can be broadly classified in two categories. The first one involves bi-level optimization models. The popularity of this methodology lies in its ability to capture in a mathematically rigorous fashion the interaction between the strategic decision making of self-interested players (modeled in the upper level) and the competitive clearing of the electricity market (modeled in the lower level). Bi-level optimization problems are usually solved after converting them to single-level Mathematical Programs with Equilibrium Constraints (MPEC), through the replacement of the lower level problem by its equivalent Karush-Kuhn-Tucker (KKT) optimality conditions.

The second one involves agent-based and reinforcement learning approaches which have been driven by the rapid advancements in the area of artificial intelligence. In this modeling framework, the above bi-level optimization problem is not converted to a single level, closed-form MPEC. Instead, the market players (agents) gradually learn how to improve their strategies by utilizing experiences acquired from their repeated interactions with the market clearing process (environment). Although the bi-level optimization approaches exhibit higher mathematical rigorousness, they are less scalable to problems with large number of players and consideration of more physical system or participants' constraints. On the other hand, the employment of reinforcement learning approaches by market players may result to significant risks for the stability of the market, since they do not incorporate a closed-form representation of the economic and technical parameters of the system.

4.1 Strategic behaviour of generation participants

Generation companies can generally exercise market power through two different strategies [59]. The first one is known as economic withholding and lies in misreporting their operating costs, i.e. reporting in their offers to the market higher than their actual operating costs. The second one is known as physical withholding and lies in misreporting their generation capacity, i.e. offering less than their actual capacity to the market.

Both strategies entail a trade-off which should be properly balanced by the strategic generation company. Specifically, economic or physical withholding will tend to increase market prices but at the same time it will tend to decrease the (energy) quantity sold by the generation company.

Economic withholding and its implications are demonstrated in Figure 3 [63]. The green line represents the actual supply curve (corresponding to its marginal cost curve) of a strategic generation company i, while the blue curve represents the supply curve reported in its bid (as-bid supply curve). In general economic withholding can potentially involve increasing the interception of the marginal cost curve with the price axis (y-axis), increasing the slope of the marginal cost curve or increasing both of them. In the context of Figure 3, the second alternative (increasing slope) applies, but the following insights are very similar in the case of any of the above alternatives. The interception of the supply curve of generation company i (green or blue line) with the residual demand curve, i.e. the demand curve expressing the demand side and the operation of the other generation companies in the market (red curve) determine the market clearing outcome.

Figure 3 demonstrates that economic withholding (reporting the blue line instead of the green line) increases the market clearing price, which has a positive effect on the generation company's i profit, while it decreases the quantity sold by generation company i, which has a negative effect on it profit. This trade-off should be properly balanced by the generation company.

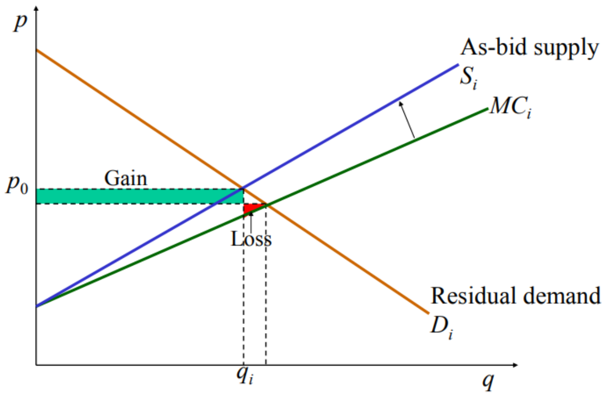

Figure 3. Illustration of market power exercise by generation participant through economic withholding [63]

Physical withholding and its implications are demonstrated in Figure 4 [64]. The right supply curve line represents the actual supply curve (corresponding to a truthful report of its generation capacity) of a strategic generation company i, while the left supply curve represents the supply curve reported in its bid; this is moved to the left as the company offers less that its actual capacity to the market.

Figure 4 demonstrates that physical withholding (reporting the left line instead of the right line) again increases the market clearing price, which has a positive effect on the generation company's i profit, while it decreases the quantity sold by generation company i, which has a negative effect on it profit. This trade-off should be properly balanced by the generation company.

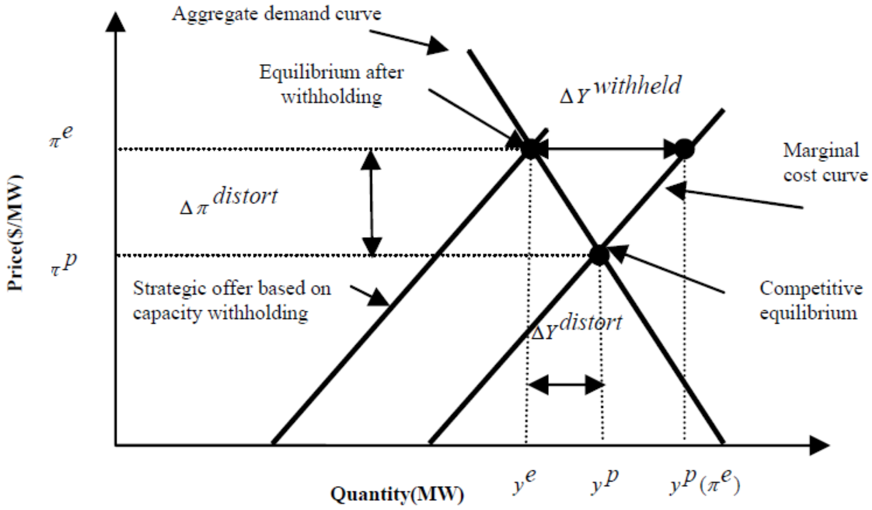

Figure 4. Illustration of market power exercise by generation participant through physical withholding [64]

A large number of papers have developed quantitative models to analyse the exercise of market power by generation companies (through either economic withholding or physical withholding). Most of these papers have employed bi-level optimisation approaches [65]-[79], while a few of them have employed agent-based models [80]-[86].

4.2 Role of flexible demand and energy storage in imperfect electricity markets

Given that demand side response (DSR) and energy storage (ES) technologies have attained increasing interest in the context of the electricity system decarbonisation (Section 1.2), there is an emerging need to investigate their role and impacts in imperfect electricity markets. This task involves two equally significant perspectives: the perspective of price-taking DSR / ES and the perspective of price-making DSR / ES.

Under the first perspective, DSR / ES owners are assumed to behave competitively and reveal their actual techno-economic characteristics to the market. The validity of this assumption is likely for independent, small-scale, distributed DSR and ES which cannot unilaterally affect the market outcome. Previous work on this area has demonstrated that price-taking DSR and ES can mitigate the exercise of market power by large generation companies.

A first stream of work on this area has focused on the self-price elasticity of the demand side and has demonstrated that it reduces the generation companies' ability to exercise market power, as demand is reduced at high market prices and thus limits the volume of electricity sold by strategic producers [87]-[92]. However, this work does not capture the time-coupling flexibility of DSR and ES. This aspect has been recently capture by a second stream of work which has focused on demand shifting and energy storage [93]-[96], the implications of which on the market power exercised by strategic producers are illustrated in Figure 5, involving a simplified market representation with two time periods (peak and off-peak) [94].

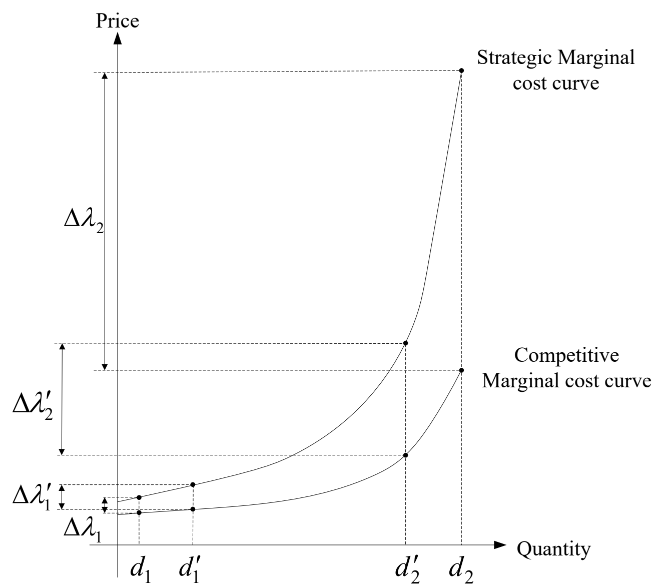

Figure 5. Illustration of impact of DSR and ES on market power exercise by the generation side

The two curves represent in a simplified fashion the aggregate supply curves of the generation side under competitive and strategic (assuming economic withholding) behaviour. DSR and ES reduce peak demand from d_2 to d_2' and increase off-peak demand from d_1 to d_1'. The price increments $\Delta\lambda$ represent the increase of the market clearing prices driven by the exercise of market power in the respective cases. As demonstrated in Figure 5, this price increase is much higher during the peak period due to the increasing slope of the supply curve.

DSR and ES reduce the price increment at the peak period from $\Delta\lambda_2$ to $\Delta\lambda_2'$ while they increase it at the off-peak period from $\Delta\lambda_1$ to $\Delta\lambda_1'$. Although the peak demand reduction is equal or even lower (due to potential energy losses associated with DSR and ES) than the off-peak demand increase, i.e. $d_2 - d_2' \leq d_1' - d_1$, the price increment reduction at the peak period is higher than its increase at the off-peak period, i.e. $\Delta\lambda_2 - \Delta\lambda_2' > \Delta\lambda_1' - \Delta\lambda_1$, due to the increasing slope of the supply curve. This effect implies that DSR and ES result in an overall reduction of the extent of market power exercised by strategic generation companies.

Under the second perspective, DSR / ES owners are assumed to behave strategically and misreport their techno-economic characteristics to the market i.e. instead of mitigating large producers' market power they exercise themselves market power. The validity of this assumption is likely for large-scale DSR and ES or a number of smaller DSR and ES operated by the same market entity (e.g. an aggregator), which can affect the market outcome through their individual actions. In the case of DSR, market power can be exercised by misreporting their actual benefit curve, while in the case of ES, market power can be exercised by misreporting their actual power or energy capacity. Previous works exploring the exercise of market power by the demand side and energy storage include [97]-[99] and [100]-[112], respectively.

5. Towards decentralised market designs

5.1 Limitations of centralised market designs

Existing electricity markets follow centralised designs. All market participants submit their economical and technical characteristics in the form of bids and offers to a central market clearing engine and the latter clears the market (it determines the schedule of the market participants and the prices based on which transactions will take place) through the solution of a global optimization problem (usually social welfare maximization). If we neglect the challenges introduced by inefficient bidding structures (Section 3) and market power issues (Section 4) this centralised approach is guaranteed to yield the (feasible and) optimal clearing outcome from the system perspective.

In the electricity markets of the past, this approach was perfectly acceptable, as the number of the market participants was relatively small (basically including a few large generation companies and a few large suppliers). However, the envisaged participation of a vast number of distributed flexibility sources (such as small-scale DSR and ES, Section 1.2) will render the communication and computation scalability of centralised designs at least questionable, in both technical and economic terms. Transmission of the diverse complex operational constraints and physical parameters of a very large number of distributed flexibility sources to the central clearinghouse will yield information collection and communication problems, while the vast number of decision variables and constraints associated with such flexibility sources will create a massive computational burden to the market operator. Last but not least, centralised designs are likely to raise privacy concerns by the consumers, who are not generally willing to disclose private information, such as habits, preferences and load assets' properties, and be directly controlled by an external entity.

5.2 Decentralised market designs

In view of these challenges, recent research work has focused on the development of alternative, decentralised market designs, which do not require full knowledge of the participants' characteristics by a central market operator. In these decentralised designs, the originally centralised market clearing problem is decomposed into subtasks that each market participant can perform individually and independently. However, the crucial challenge behind these decentralised designs is to achieve feasibility and optimality for the market clearing outcome. Such designs can be broadly classified into two categories: semi-decentralised and fully decentralised designs.

The first category includes price-based coordination architectures, based on dual decomposition principles and involving a two-level iterative process [45], [113]-[123]. At the local level, individual participants determine their optimal responses to a set of given electricity prices by independently solving their economic surplus maximization problems (profit maximization for generation participants and utility maximization for demand participants). At the global level, the market operator updates these prices in order to drive participants' responses to the optimal market clearing solution. This type of designs is semi-decentralised, in the sense that it stills requires a central market operator to update the prices transmitted to the market participants, although this market operator does not have centralised knowledge of the participants' techno-economic characteristics.

However, a key challenge of such price-based designs is associated with the notorious loss of diversity and response concentration effects, driven by the self-interested behaviour of market participants. Specifically, the response of flexible loads and the charging response of energy storage are discontinuously concentrated at the periods with the lowest prices, yielding significant new demand peaks, while the response of some generators and the discharging response of energy storage are discontinuously concentrated at the periods with the highest prices, yielding significant new demand valleys. As a result, the market clearing outcome is highly inefficient (exhibiting high system costs) or even infeasible, in the case the new demand peaks and valleys breach the technical constraints of the network or the generation side.

In order to address these effects of loss of diversity and response concentration, there is a need to move away from traditional price-based approaches and design smarter coordination signals. In [45], [117]-[118], [121] and [123] the authors proposed three alternative smart designs towards this direction: i) imposing a relative flexibility restriction on market participants, in order to explicitly prevent them from concentrating their demand at the same periods, ii) penalizing the extent of flexibility utilized by market participants through a non-linear flexibility price, in order to de-motivate them from concentrating their demand at the same periods, and iii) randomizing the prices transmitted to different market participants, in order to diversify their responses.

The second category of decentralised market designs completely avoids the need for a central market operator, and the market clearing process is based solely on the bilateral exchange of messages between the different market participants [124]-[134]. In this sense, this type of designs is fully decentralised. Such designs are based on novel distributed coordination approaches, including consensus algorithms and alternating direction method of multipliers (ADMM). In these approaches, the market participants exchange signals until they reach a consensus about certain global variables (e.g. the market clearing prices). Due to the absence of a central market operator, the challenges to achieve feasibility and optimality for the market clearing outcome are even more pronounced with respect to semi-decentralised approaches. Therefore, such fully decentralised approaches are only examined in a research context and their proposed applications involve small-scale, local markets rather than wholesale electricity markets.

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