- First, we should make sure that distribution tariffs become reasonably cost-reflective. Flexibility contracts are not an alternative to cost-reflective distribution tariffs, but they can complement reasonably cost-reflective tariffs.
- Second, signals from tariffs can be combined with flexibility contracts, and we can combine mandatory with voluntary flexibility contracting. The existence of a mandatory scheme does not have to imply that it is often used; it can be the backup scheme.
- Third, we invite everyone to keep an open mind regarding the issue of short-term versus longer-term contracting of flexibility by DSOs. TSOs have just been asked to make a significant reduction in their long-term reservations of resources for balancing or re-dispatching, so it seems contradictory that DSOs would now be allowed to make long-term reservations to manage local congestion. However, in order to fully explore the potential of using flexibility to save distribution grid investments, we could allow this to happen, and it is already happening in some countries. If we then discover that this reduces the distribution costs at the expense of the whole system costs, we will need to intervene.

There are many more details to figure out in the coming years. Key questions include:

- How important is it to consider the whole system perspective versus the local dimension when making the trade-off between flexibility and distribution network expansion?
- What is the impact of TSO–DSO coordination on the trade-off?
- How context-specific is the flexibility potential; in other words, ‘low-voltage versus medium-voltage grids’, ‘rural versus urban distribution grids’, ‘congestion caused by generation peaks versus consumption peaks’?

DISTRIBUTION NETWORK PLANNING DURING THE ENERGY TRANSITION: SYNERGIES BETWEEN REAL OPTIONS & FLEXIBILITY MECHANISMS

Miguel A. Ruiz, Tomás Gómez, Rafael Cossent, and José P. Chaves

The increase in renewable generation and electrification of energy sectors such as heating and cooling, transport, and industrial processes could require massive investment in electricity networks unless flexibility mechanisms are efficiently developed to handle local variability of loads and generation. The need to perform an economic assessment of these flexibility mechanisms urges a paradigm change in current network planning practices.

Distribution system operators (DSOs) face increasing uncertainties about the penetration of distributed energy resources (such as renewable generation and storage) and the advent of new loads due to increasing electrification. Distribution network planning (DNP) presents a trade-off between maintaining a high service level to end consumers and avoiding costly irreversible network reinforcements. When peak demand is close to the network capacity limits, the DSO should decide whether to reinforce the grid. Knowing that if demand does not grow as expected the investment decision would result in an unnecessary cost, whereas if demand grows above expectations this could result in quality-of-service degradation and potential damage to installations.

This article addresses some of the challenges that DNP is expected to face during the following years due to energy transition. We show how real options can be used in the context of DNP, and the potential benefits it brings for valuing grid investment deferral. Finally, we discuss how projected future demand scenarios suit real options strategic planning.

Distribution network planning under the energy transition

Growing renewable connections impose challenges for network operation and planning, since some of these (such as solar and wind) are variable and not dispatchable. However, the uptake of electric vehicles, heat pumps, power-to-gas, and other technologies offers an opportunity, as they can serve as storage devices and flexible demand, offering local flexibility in distribution networks. Nonetheless, the uncertainty about demand evolution during the upcoming years is high, since the adoption pace of these new technologies is unknown. This situation accentuates the trade-off between maintaining a high service level and avoiding unnecessary investments. Thus, presenting a challenge for decision-makers in DNP.

Flexibility mechanisms such as flexibility markets, bilateral contracts, or connection agreements will be necessary to take advantage of flexible demand, generation, and storage. These flexibility mechanisms potentially allow DSOs to delay irreversible network reinforcement. In the context of high uncertainty about future demand, the alternative ‘wait and see’ how demand evolves while maintaining high service levels thanks to flexibility mechanisms has caught the attention of analysts and policymakers. For example, EU directive 2019/944 article 32.3 indicates that DSOs shall consider demand-side response, energy storage, and energy efficiency as an alternative to system expansion. Ofgem RIIO ED2[26] opens the door to new valuation techniques, indicating that DSOs could recognize the option value that flexibility and energy efficiency can provide. The benefit of reducing investment in underused infrastructure by delaying commitment to irreversible investment is well understood.

However, traditional economic analyses based on discounted cash flow (DCF) are still being used and proposed as methods to evaluate alternatives in DNP. These traditional methods ignore the strategic value of flexible management decisions under uncertainty. Thus, we encourage using real options to better evaluate DNP alternatives, especially during the energy transition.

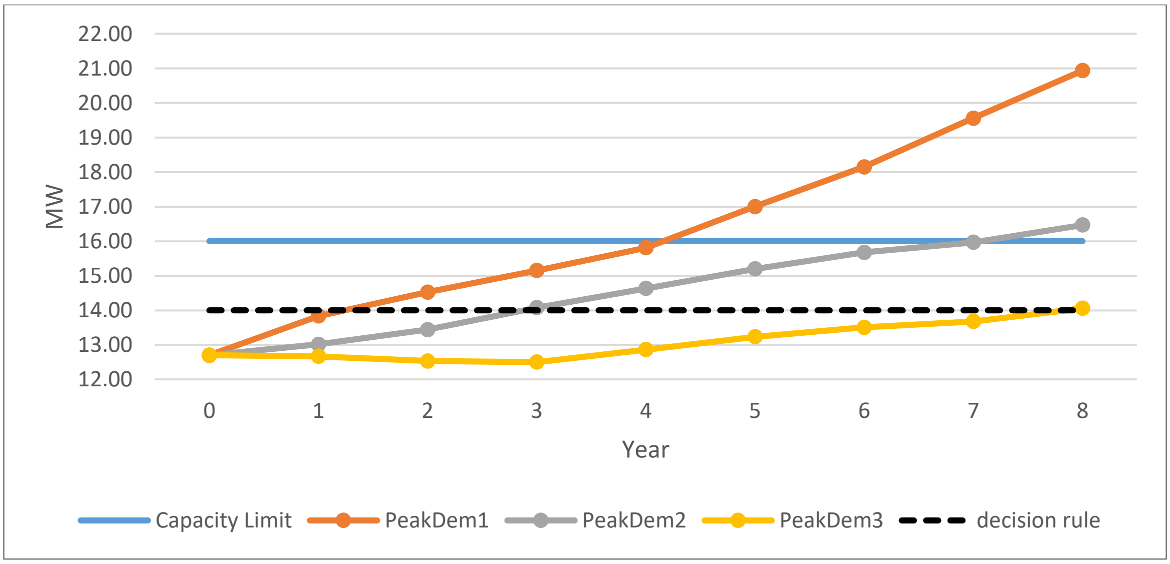
Real options characterization for DNP

Traditional investment valuation techniques based on DCF are deterministic. These techniques result in a series of fixed decisions projected into the future based on today's forecast. In contrast, real options theory is a conceptual framework for strategic planning under uncertainty that captures the decision-maker's flexibility to adapt to future conditions. In real options theory, future investment decisions are contingent on resolving future uncertainties. Thus, it results in dynamic strategies with defined reactions/responses to future events/conditions during the planning period. Next, we characterize deterministic plans and the real options approach in the context of DNP.

Figure 1 illustrates a DNP example, where the blue line (16 MW) represents the initial capacity limit for the network, while three lines (orange, grey, and yellow) represent the projected peak demand under uncertainty, modelled through three scenarios. Let's consider only one upgrade alternative (invest in a feeder with 2-year lead time) to solve any potential overload. A deterministic plan would be a fixed decision for the analysed period. For example, invest in a feeder at the end of year 2. Considering a 2-year lead time for the feeder, this investment will avoid the potential overload from year 5 onwards.

Alternatively, the real options approach would result in a decision contingent to the information generated over time as uncertainty leaves way to information. For example, invest in a feeder when peak demand reaches 14 MW (black dotted line) – this is similar to the proposal by Jonathan A. Schachter et al.[27] This strategy avoids potential overloads and results in the same investment as the previously presented plan only if demand grows fast (orange line), but it delays the investment if demand grows slowly (grey or yellow lines). This brief example shows how a real options approach offers a clear advantage versus deterministic plans when planning under uncertainty.

Figure 1: Network capacity vs peak demand



[26] *RIIO-ED2 Business Plan Guidance*, Ofgem, 2021.
[27] Jonathan A. Schachter et al., (2016), 'Flexible Investment under Uncertainty in Smart Distribution Networks with Demand Side Response: Assessment Framework and Practical Implementation', *Energy Policy*, 97, 439–49.

Valuing flexibility and investment deferral through real options

There are synergies between flexibility mechanisms and real options. Since one DNP principle is to maintain high service levels by avoiding non-served energy imposed by exceeding network operational limits, any investment decision in traditional planning is highly influenced by the worst possible scenario (fastest demand growth projected). Therefore, not considering the possibility of a greater investment deferral when demand increases slower than the fastest scenario limits the deferral period. Thus, limiting the value of flexibility mechanisms.

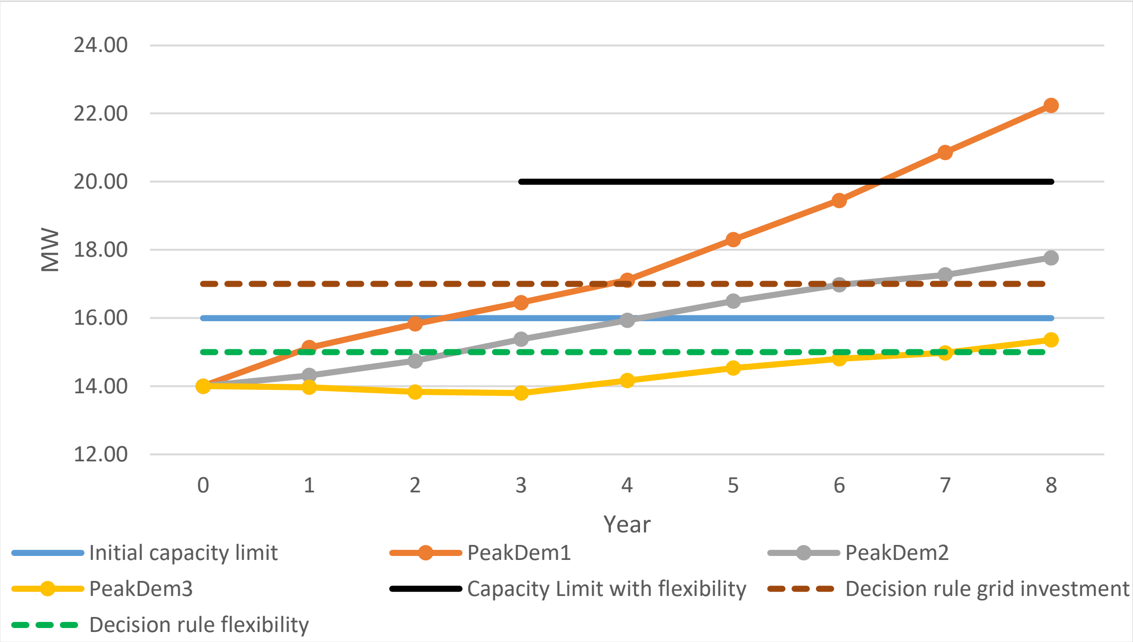
Real options strategic planning allows the decision-maker to evaluate how future decisions are contingent on the newly available information over time. Thus, the investment deferral period will be similar to traditional planning if demand grows at the fastest projected pace. The deferral will increase if demand grows below that pace, increasing the expected investment deferral and, consequently, unveiling the value of flexibility mechanisms.

Let's consider an example with two possible distribution upgrades (depicted in Figure 2). Consider two alternatives:

- Invest in a feeder (2-year lead time and 12 MW additional capacity for the grid).
- Invest in a demand response contract (1-year lead time, 4 MW additional capacity, and yearly contract renovation).

We consider three scenarios for future peak demand (orange, grey, and yellow lines). For the sake of simplicity, no overload is permitted. The grid initial capacity is 16 MW (blue line).

Figure 2: DNP. Real options vs traditional planning considering flexibility mechanisms



For the highest growth scenario (orange line), the first projected overload occurs during year 3, because demand exceeds the initial grid capacity (blue line, 16 MW).

- The first alternative is to invest in a feeder (12 MW) today (end of year 0). This feeder is built during years 1 and 2 (2-year lead time), resulting in the feeder being ready for use at the beginning of the third year (total network capacity of 28 MW), avoiding any potential overload during the planning period.
- A second alternative is investing in flexibility (4 MW), delaying the grid investment.

Next, we evaluate these alternatives by considering traditional planning and real options.

For *traditional planning*, to avoid the projected overload occurring in year 3, we need to invest in a demand response contract at the end of year 1. The additional 4 MW (black line, total admissible peak demand of 20 MW) will be available at the beginning of year 3 (1-year lead time). After this, the second overload is projected during year 7. We invest in a feeder at the end of year 4 with a 2-year lead time, being available at the beginning of year 7, avoiding the projected overload. Table 1 summarizes the traditional investment plan described in this example (in traditional planning the fastest demand growth is the most influential scenario that imposes the needed investment).

Table 1: Traditional investment planning

(flex investment in year 1, grid investment in year 4)

		Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Scen 1	Flex		X							
	Grid					X				
Scen 2	Flex		X							
	Grid					X				
Scen 3	Flex		X							
	Grid					X				

X: decision to invest in demand response contract (flex) or in a feeder (grid). Green/Yellow fill: flexibility mechanism/Grid investment in operation.

For *real options*, we define the strategy with two decision rules:

1. Invest in flexibility when demand reaches or surpasses 15 MW (green line),
2. Then invest in the feeder when demand reaches or surpasses 17 MW (brown line).

- Scenario 1 (orange line) surpasses the first investment trigger (green line, 15 MW) during year 1. Then, the investment in flexibility occurs at the end of year 1, being available for operation at the beginning of year 3. Later on, during year 4, this scenario surpasses the second investment trigger (brown line, 17 MW). Thus, following the defined strategy, the feeder investment occurs at the end of year 4, resulting in the grid investment operating from the beginning of year 7.
- Following the same logic, Scenario 2 (grey line) surpasses the green line during year 3. Flexibility investment is decided at the end of year 3 and is available for operation at the beginning of year 5. Afterwards, the feeder investment occurs in year 7 when the grey line crosses the brown line.
- The third scenario (yellow) crosses the green line during year 8 and never surpasses the brown line. Thus, the strategy results in flexibility investment at the end of the eighth year and no feeder investment.

Table 2 summarizes the investment decisions for this strategy, resulting in no overloads.

Table 2: Real options planning

(flex investment at 15 MW, Grid investment at 17 MW)

		Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Scen 1	Flex		X							
	Grid					X				
Scen 2	Flex				X					
	Grid								X	
Scen 3	Flex									X
	Grid									

Notations as in Table 1.

Comparing Tables 1 and 2, traditional deterministic planning leads to the same decisions for all three scenarios (invest in flexibility in year 1, and invest in the grid in year 4). However, the real options approach leads to different decisions contingent on information available over time. It leads to the same investment decision as in traditional planning for the first scenario (highest growth demand), and delays the investment decisions for scenarios 2 and 3. Thus, lowering the expected net present cost compared to traditional planning.

Additionally, traditional planning could lead to the rejection of flexibility mechanisms, due to poor valuation and analysis. To illustrate this, please consider the example presented in Figure 2.

- The first alternative is to invest in grid reinforcement today and not use the flexibility mechanism.
- The second alternative is to invest in the flexibility mechanism and defer the grid reinforcement.

The maximum amount we can spend in the flexibility mechanism is equal to the savings produced by deferring the grid reinforcement in the second alternative. If the flexibility mechanism costs less than this maximum amount, alternative 2 is preferred. Table 1 shows the traditional plan for the second alternative in the mentioned example, where the grid investment occurs in the 4th year for all the scenarios. Therefore, the expected deferral for the second alternative in traditional planning is 4 years. Table 2 shows the real options approach for the second alternative, where the grid investment occurs in the 4th year for the first scenario, in the 7th year for the second scenario, and there is no investment during the eight years planning period for the third scenario. Thus, the investment deferral for the second alternative in the real options approach is greater than in traditional planning. Therefore, the maximum amount we can spend on the flexibility mechanism in the real options approach is greater than in traditional planning. Thus, maintaining traditional planning techniques could lead to not using flexibility mechanisms, due to poor valuation of the DNP alternatives.

In conclusion, the real options approach has the potential to improve decision-making under uncertainty in DNP, reducing costs and capturing the benefits derived from the flexibility mechanisms. Still, one question remains. Are the projected scenarios for electricity peak demand suitable for real options strategic planning?

Projected demand scenarios and real options

The logic behind real options is that considering the unfolding information for flexible decision-making over time would lead to better results. In the context of DNP, this implies the assumption of some positive correlation for peak demand variations over time inside each projected demand scenario. Otherwise, unfolding information would be misleading and future decisions based on that information will lead to poor decision-making. Then, we should look at projected demand scenarios during the energy transition.

UK national grid ESO depicts four different scenarios for future electricity peak demand during the energy transition.[28] As shown in Figure 3, these scenarios present trends where unfolding information gives valuable insight of future conditions (since the changes in trend inside each scenario are smooth); a conflicting point is shown at the beginning of the yellow line ('Consumer Transformation' scenario) where the trend rapidly changes from decreasing to growing. In conclusion, these scenarios are suitable for a real options analysis. As distribution grid local projections for demand are influenced by local conditions, some regions will be more suitable for a different transition. For example, single-family homes can take more advantage of solar panels and form energy communities, while generation-driven areas can take advantage of storage technologies. So, we expect variations of peak demand following different trends depending on different regions. Other local conditions highly influencing peak demand projections are urbanistic plans, and industrial development. These types of changes are predictable and are also suitable for real options analyses.

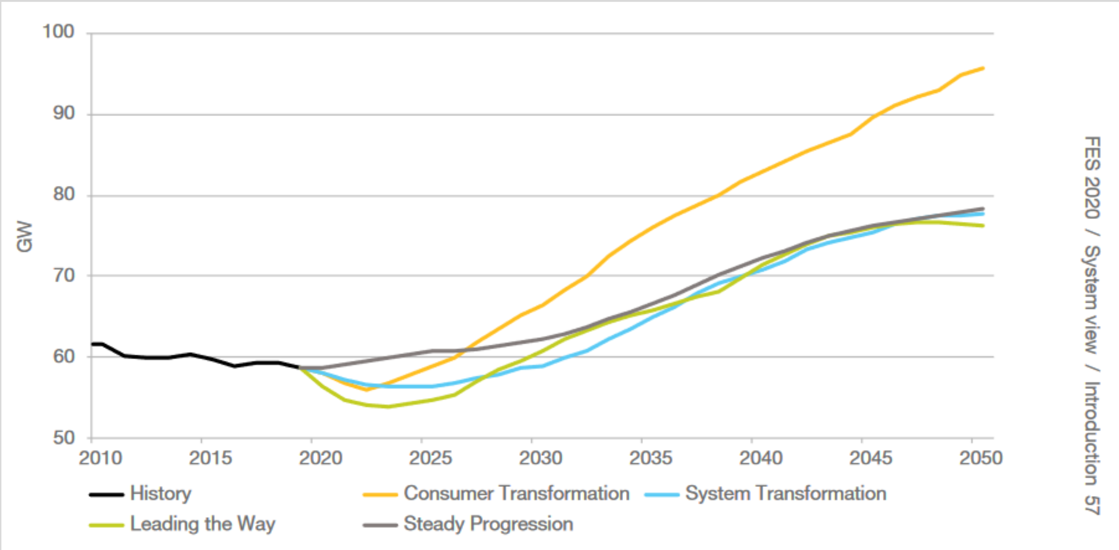
Considering the scenarios presented by UK national grid ESO (Figure 3), traditional planning would be highly influenced by the 'Consumer Transformation' scenario (yellow line), resulting in unnecessary costs if future demand evolves similarly to any of the other three projected scenarios. Otherwise, strategic planning through real options will adapt to information over time, similar to Table 2 in the previous example, avoiding unnecessary costs.

Conclusions

Flexibility mechanisms are commonly accepted as temporary alternatives to traditional network reinforcement of the distribution network (other benefits not discussed in this article include faster connection of new customers and grid operation support). These solutions may mitigate the risk of investing in infrastructures that become underused. Flexibility mechanisms allow the planner to delay the network reinforcement until the risk of underutilization is reduced. However, traditional planning based on DCF ignores the fact that future investment decisions are flexible and the DSO can respond to demand evolution over time, thus limiting the value this delay brings. This can lead to poor decision-making and overinvestment during the energy transition, resulting in a higher cost for bill payers. The presented real options conceptual framework has the potential to unveil the economic value of these flexibility mechanisms, as future decisions can be modelled as responses to information available over time. In conclusion, the high uncertainty faced by DNP during the energy transition urges a paradigm change in current practices to avoid incurring unnecessary costs.

[28] United Kingdom National Grid ESO, *Future Energy Scenarios 2020*.

Figure 3: Electricity peak demand scenarios in 2020



Source: United Kingdom National grid ESO, Future Energy Scenarios 2020.

Additional considerations

The example presented here ignores many complexities that real networks can face. The network can experience overloads in different locations during the planning period, the decision-maker could estimate the duration of the projected overloads, and the expected value of the associated non-served energy when comparing the investment alternatives. The uncertainty might concern not only peak demand, but also flexibility prices. Furthermore, the projected scenarios can present variations around each trend. However, these complexities can be modelled and the synergy between flexibility mechanisms and the real options approach still holds.

The interaction between the proposed analytical approach and the current regulatory framework should also be considered. The expected results of the real options approach for cost minimization rely on investment rules defined for the selected strategies. However, misaligned regulatory incentives could push decision makers not to follow the selected strategies and produce unexpected outcomes. For instance, flexibility procurement is an operational expenditure (OPEX), while grid reinforcement is a capital expenditure (CAPEX). Therefore, total expenditure (TOTEX) incentives, non-biased on CAPEX or OPEX, are key to guide cost minimization in this context. This effect has been already highlighted by the Council of European Energy Regulators.[29]

COORDINATION OF TRANSMISSION AND DISTRIBUTION SYSTEMS: A PROPOSED FRAMEWORK

Dimitra Apostolopoulou and Rahmat Poudineh

Introduction – (R)Evolution of power systems

Power systems are undergoing radical transformations that comprise, among other factors, a shift to renewables-based generation; deployment of 'edge of the grid' or distributed energy resources (DERs – in other words, energy resources connected at the distribution level); and a trend towards decentralized power systems (for example, microgrids). These are driven by technological advances, cost declines in DERs and in information and communication technologies, as well as policies, incentives, regulatory paradigms, and consumer preference trends. These changes have led to a shift in the traditional power systems' operations from a centralized, one-way power flow to a decentralized, bi-directional power flow. The deployed DERs can offer numerous services to the grid such as reserve capacity and voltage support, together with other services that are seen as an alternative to 'wire only solutions' to solve network constraints, and which can be used to delay or defer potentially costly network upgrades. However, these can only be fully leveraged under an effective coordination framework

[29] *Regulatory Sandboxes in Incentive Regulation*, Council of European Energy Regulators, 2022.

between the distribution and transmission systems at their interface. The coordination framework developed in this article may be used as a guideline for how this may be achieved and how obstacles may be overcome.

Obstacles arise under the current system operational paradigm to integrate DERs both at the level of the transmission system operator (TSO) and the distribution system operator (DSO). For instance, complications for the TSO arise due to the lack of visibility of DERs; unpredictability of DERs' responses to TSO dispatch signals; forecast errors introduced to the interchange between areas in the transmission and distribution interface; and the long-term growth scenarios of DERs that need to be accounted for in transmission planning. On the other hand, DSOs are concerned about the ability to adjust DERs' output to maintain a reliable operation as well as (rather like TSOs) their unpredictability and long-term growth scenarios for planning purposes. In practice, this has led to limited use of DERs in optimizing power system operation. For example, in New York, demand response programmes were only activated on ten days during a three-month period, due to lack of coordination between utilities and the NYISO.[30] Furthermore, DERs usually have smaller capacity and cannot participate in, for example, European wholesale markets unless aggregated on the order of 1 to 5 MW.[31] Efforts have been made by regulatory bodies to propose solutions to overcome such barriers and incentivize investment in DERs. For instance, in the US, the Federal Energy Regulatory Commission (FERC) issued Order No. 2222 to open wholesale markets to competition from DERs. The order allows aggregations of DERs (in the order of a minimum of 100 kW) that meet the physical and operational requirements of the system operator to participate in the market under the same conditions as traditional resources.

Although the aforementioned measures to boost deployment of DERs are necessary, they are unlikely to be sufficient. In order to provide incentives for DER investments and operate the entire grid in an optimum way, a framework is needed to coordinate the operation of different resources at the grid edge with the bulk system. Under such a framework that coordinates the actions of TSO and DSO, DERs could offer a variety of services to the power system. These can be broadly categorized into market-related services (such as energy, capacity, black start, load shifting) and network-related services (such as network constraint management, voltage control, power quality, energy loss reduction).

TSO–DSO interactions

Many different TSO–DSO coordination architectures are proposed in the literature, they vary from centralized to totally decentralized approaches.

- In centralized schemes the TSO is responsible for satisfying the system demand in both the transmission and distribution systems with the use of generators at both levels. This is also referred to in literature as the 'whole TSO model'.
- In decentralized schemes, the TSO and DSO are responsible for the operation of their own grid, but they need to agree on the point of common coupling (PCC)[32] power flow interchange. In such schemes, the DSO operates its local system by buying energy from the transmission system, taking into consideration the electricity price at the PCC. The DSO can also sell energy to the transmission system by participating in the TSO market.

Decentralized TSO–DSO coordination approaches can be further categorized into hierarchical or distributed.

- In hierarchical TSO–DSO coordination schemes, the interaction between distributed resources in the distribution system and the transmission power system is akin to a leader–follower type, where the transmission system has priority in making decisions, while the distribution system makes decisions subject to the constraints of TSO decisions. This is also known as the 'hybrid DSO model'.
- In distributed TSO–DSO, all local DERs can participate in the market to meet the load; this is also called the 'whole DSO model'.

Centralized schemes face a variety of regulatory challenges that arise from the fact that private information needs to be exchanged between TSOs and DSOs and ownership of responsibility with regards to reliability and resilience is not clear. These factors make their actual implementation difficult. In contrast, decentralized schemes are likely to be more in line with the decentralization paradigm in the power system but need to be further studied so that they: respect privacy concerns of the

[30] Waldoch, C. (2022), 'Coordinating the distributed energy future. Lessons from the NYISO', LeapfrogPower, February 2022.
[31] ENTSO-E, 'Survey on ancillary services procurement, balancing market design 2017', May 2018.
[32] PCC is the boundary between the transmission and distribution systems – namely the transformer between the medium-voltage distribution system, managed by the DSO, and the high-voltage transmission system, managed by the TSO.

stakeholders involved, are computationally efficient, depend on a realistic communication infrastructure, achieve an optimal outcome (for example in terms of cost), relieve congestion, and facilitate the integration of DERs.

In order to further the research in this domain, several pilots have been developed. The SmartNet (2016–2019) was a European project whose aim was to compare different TSO–DSO coordination schemes and real-time market architectures for acquiring ancillary services from distributed resources. More specifically, five different co-ordination schemes were proposed:

i. centralized ancillary services market model;

ii. local ancillary services market model;

iii. shared balancing responsibility model;

iv. common TSO–DSO ancillary services market model;

v. integrated flexibility market model.

The main differences between all these architectures are the allocation of responsibility to operate the system and the exchange of information, for example, bids and network topology.[33] CoordiNet (2019–2022) is another European research project, which aimed to demonstrate how TSOs and DSOs should act in a coordinated manner to procure and activate grid services most reliably and efficiently, by defining standardized products that may be exchanged between TSOs and DSOs. In the UK, where it is anticipated that up to 45 per cent of total generation capacity will be connected to the distribution networks by 2030, Centrica has developed a local energy market platform in Cornwall in which the TSO and DSO procure flexibility services. Within the UK system, flexibility markets are already under trial in most distribution network regions; some of these are using the Piclo flex platform that aids in the standardization of flexibility products and the efficient use of DERs, such as for peak shaving, without which, network reinforcement could have been triggered.

Proposed coordination framework – enhanced DSO role

All these efforts have paved the way to a better understanding of coordination requirements between TSOs and DSOs. However, further advances both in technology as well as in market designs are necessary to achieve a smooth coordination between the bulk system and the edge of the grid that will allow for an efficient, reliable, and sustainable operation of the entire grid. In this regard, we envision power systems as a collection of subsystems at different layers that are connected with each other (a ‘fractal grid’), exchanging power and non-private information; and operating under a market environment. Each layer is responsible for its own operation in a sustainable, reliable, and cost efficient manner, only having access to the interchange from the layer above or below but not to its detailed representation. More specifically, under the proposed coordination framework, the layers correspond to the boundaries of operation of TSOs and DSOs.

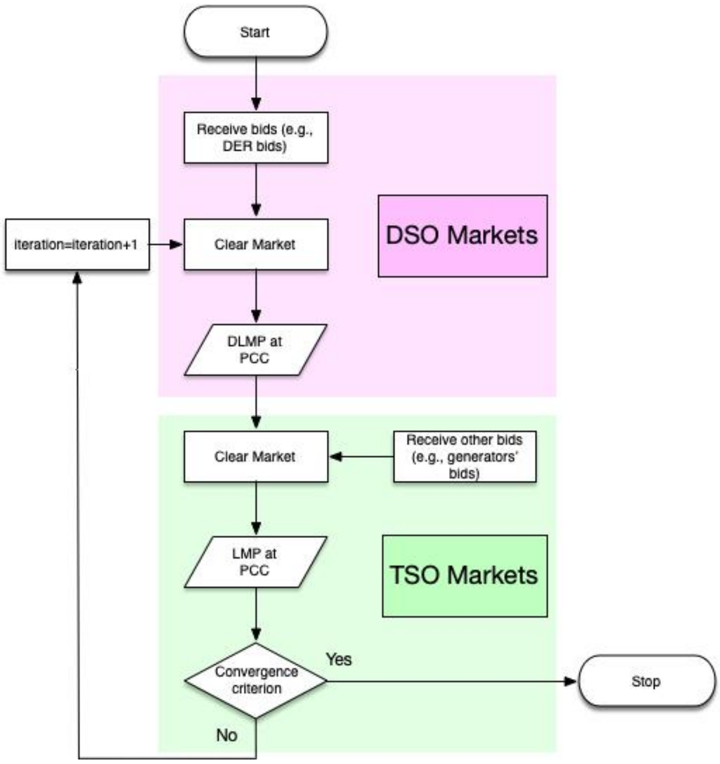
DSOs optimize local markets at each PCC; they do so by taking into account the cost of energy at the PCC and the value of DERs’ services. Then, the TSO optimizes the bulk system rather than that of individual DERs (only seeing one virtual resource at the PCC) and is responsible for meeting the net interchange at the PCC. In such a paradigm, DERs only communicate with the DSO and submit their bids to the local or peer-to-peer markets. The DSO sends appropriate control signals to DERs to meet the TSO instructions. The new role of the DSO includes acting as an interface between TSOs and prosumers – for example, DER owners and consumers. Such an approach solves the issue of decreased visibility of TSOs in terms of connected and ready to be used DERs. The TSO is responsible for system reliability only at the PCC, and the DSO is responsible from the PCC to the customers’ meters. The TSO and DSO share layered responsibilities – for example in terms of frequency response based on load share.

Under the proposed framework, the operating schedule of the resources for the entire system is achieved with an iterative process of non-private information exchange between the TSO and DSO until all parties reach consensus and have no economic incentive to deviate from the agreed schedule. This information includes the locational marginal prices (LMPs) and distribution locational marginal prices (DLMPs) at the PCC. This optimal solution – which performs as if one entity were operating the entire power grid – functions as if it produces an optimal power flow with the objective of maximizing social welfare (such as cost minimization, and voltage regulation) with access to the full nodal network of the TSO and DSOs and all the resources’ bids (which would be unrealistic of course). However, in the proposed framework, this is achieved with no exchange of private information (such as network topology or bids) between the TSO and DSO, by using tools of distributed optimization

[33] Network topology’ refers to the manner in which the links and nodes of a network are arranged to relate to each other.

as depicted in Figure 1. The proposed scheme also includes for all parties to be compensated in a 'fair' manner for services they provide to reach the socially optimum outcome, thus incentivizing them to act accordingly. This is achieved by using information in terms of power flows in each subsystem and pricing signals showing the cost/benefit of providing an additional MW of power at each location in the network, with the use of nodal pricing. This compensation is an important aspect, since there are occasions where actions that benefit the TSO may be detrimental for the DSO and vice versa. The proposed framework is scalable and at the same time increases system resiliency and security, due to the detailed representation of the underlying physical system in parallel with the use of layers that allow for scalability.

Figure 1: Iterative process of TSO–DSO coordination until they reach consensus

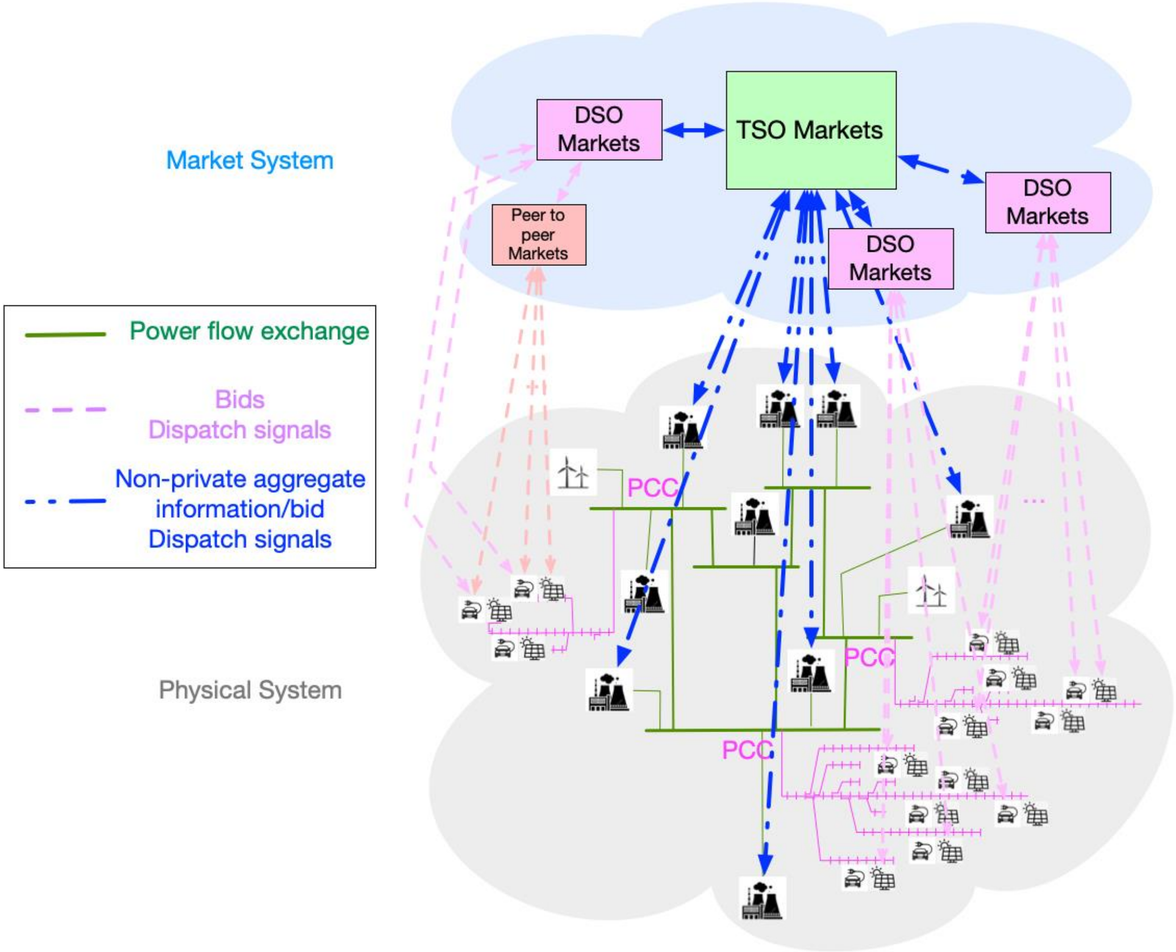


Source: authors

The next question that arises is how often this iterative process, namely the market clearing process, between the TSO and DSOs will be performed. The current day-ahead and real-time markets are poorly designed for DERs. Day-ahead DER forecast errors create exposure to real-time price variations, as resources committed in the day-ahead market are required to rebalance in real time, challenging the business model for DERs. Intraday markets with multiple discrete intermediate auctions between the day-ahead market and real-time market are necessary to enable proper integration of DERs and efficient mitigation of forecast uncertainty risk. The choice of discrete auctions is because continuous intraday markets, as currently designed in Europe, do not provide an appropriate price signal for transmission congestion. This is due to the fact that they are allocated on a first-come first-served basis and result in suboptimal allocations of transmission capacity that in turn lead to increased re-dispatch and curtailment costs. As such, we suggest that the proposed framework is solved in day-ahead (gate closes 12 p.m. the day before dispatch), in discrete intraday (gate is open up to 60 minutes before dispatch), and in real-time (gate is open 5 minutes before dispatch) markets. The proposed framework provides market-based locational value of DER assets through the use of DLMPs for all phases and nodes. The exchange of information and power and the market structure of the proposed framework are depicted in Figure 2.

In the proposed scheme, the role of distribution systems is very active, as DSOs play an important role in its successful implementation. The first question that needs to be answered here is what will the DSO functions include? The DSO is responsible for applying the proposed framework as far as its share is concerned – in other words, to organize local markets that coordinate the purchase and sale of power and energy; forecast future load levels that need to be met; balance load and generation; perform contingency analysis; be responsible for the interchange of power to the TSO markets; respond to outages and perform restoration; and provide billing services to market participants. Besides the aforementioned functions that concern the operational stage of its system, the DSO is responsible for planning processes – such as interconnection requests within its service area and maintenance.

Figure 2: Physical and market representation of proposed TSO–DSO coordination framework



Source: authors

The next question that needs to be answered is who will serve as a DSO? Is there a need for an independent DSO, or can network utilities serve this role? We envision the DSO role to be taken up by utilities under a regulated framework. In this regard, the economic transactions with prosumers in its territory will be on the basis of regulated tariffs that incorporate the cost of capacity, energy, and ancillaries in the DSO and TSO markets. Under certain conditions, DSOs might be allowed to own DERs, so that they become a potential market participant in addition to being the market operator. Under such a paradigm, the utility will help to first initiate and promote the DSO markets; however, there might be occasions of conflict of interest as well as issues with unbundling which prevent network companies from owning generation assets. These might be resolved by separating distribution network ownership and operation, although such an approach has advantages and disadvantages which need to be properly evaluated in this context.

Challenges and how to overcome them

There are some differences between the new role of DSO and the established role of TSOs, which make the implementation of the proposed framework challenging. For example, no legislation is in place to mandate consumer participation in the local DSO market, unlike the mandate currently governing generators' participation in national TSO markets. However, consumer participation is essential for a successful implementation of the DSO concept.

A desirable outcome of a successful DSO implementation is customer investment in DERs that would increase the number of participants in the DSO market and thus increase its liquidity. The number of market participants in wholesale markets is orders of magnitude smaller than those that will participate in DSO markets; making its clearing more complex. Moreover, due to the nature of the resources connected at the distribution system that inherently generate inter-hour interactions (in other words, market clearing of consecutive hours is correlated), the market clearing needs to be multi-hour compared to spot clearing.

These resources include demand response (such as thermostatically controlled loads; energy storage; electric vehicles; and CHP), whose operation span is several hours. Many market protocols today treat storage when charging as a load and when discharging as a generator, requiring separate schedules/offers for each, which fails to fully optimize the use of storage.[34] As such, we propose looking at a rolling 24-hour horizon when clearing the market, so that the natural characteristics of DERs are taken into account. More specifically, the proposed TSO–DSO coordination framework incorporates a multi-hour optimal power flow that is solved across a 24-hour time horizon, using model predictive control. For example, in the real market setting, every five minutes the system states are updated and the multi-hour optimal power flow is solved, and the time horizon recedes by another five minutes. It is evident that the proposed framework, in the real-time markets, results in a large-scale problem when applied in real systems, thus suffering from dimensionality issues besides using layers and distributed optimization techniques, as described above. To address these, we further alleviate complexity issues by using a simplified representation of the physical network, for example, by using linearized power flow equations.

A DSO market can only be realized if appropriate communication infrastructure is installed in distribution systems that are reliable, scalable, and interoperable and will allow for real time monitoring and data exchange, collection, and analytics. However, DSOs are reluctant to invest in such infrastructures and prefer to carry out investments in traditional grid elements – such as overhead lines and transformers. Incentives should therefore be provided in order to encourage DSOs to turn their efforts toward intelligent monitoring schemes in the future.

Final thoughts

As the power grid moves from the ‘Edison Era’ to the ‘Google Era’, there is an opportunity to build a more reliable, secure, sustainable, flexible, and economic electricity grid. This is facilitated with the participation of prosumers in peer-to-peer or DSO markets, the results of which in turn participate in TSO markets. A potential manifestation of this TSO–DSO interaction is described in this article and may be used as a guideline for actual implementations. It achieves the following objectives:

i. respects privacy concerns of entities involved;

ii. compensates players for achieving social welfare;

iii. incentivizes investments and allows efficient use of DERs;

iv. is scalable, robust, and transparent;

v. ensures reliable and safe operation of the grid, provides affordability and non-discriminatory access to prosumers, and is resilient to disruptive events.

Obstacles such as scalability can be overcome with the proposed layering structure. The unique characteristics of DERs – namely day-ahead, intraday, and real-time – are taken into account in the structure of the proposed markets designs, with a multi-hour setting that facilitates the use of renewable resources whose forecast error is near zero when approaching real time.

THE FUTURE OF NATURAL GAS NETWORKS IN EUROPE

Katja Yafimava

The tale of two networks: (bio)methane and hydrogen

Over the course of 2020 the European Commission (EC) developed several policy initiatives, aimed at the implementation of the European Green Deal and the Climate Law, including the European Union (EU) Hydrogen Strategy. By promoting hydrogen, the EC has opted for a lower-cost decarbonization pathway of ‘hybrid’ electrification – using a mix of electrification and gas – while accepting that full electrification would be significantly more expensive and would probably not be technically feasible.[35] This approach has been supported by the European regulatory authorities, as evident from the 2018 Madrid Forum conclusions, which stated that:

[34] G. C. Gissey, P. E. Dodds, and J. Radcliffe, ‘Market and regulatory barriers to electrical energy storage innovation’, *Renewable and Sustainable Energy Reviews*, vol. 82, 2018.

[35] Most studies (including EC) see a mix of electrification and gas as a lower-cost decarbonization pathway for most countries than full electrification.