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Local Electricity Flexibility Markets in Europe

Chondrogiannis, S., Vasiljevska, J., Marinopoulos, A., Papaioannou, I., Flego, G.

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Contact information
Name: Stamatios Chondrogiannis
Address: JRC – Via E. Fermi 2749 – I – 21027 ISPRA (VA) – Italy
Email: stamatios.chondrogiannis@ec.europa.eu
Tel. +39 0332 785324

EU Science Hub
https://joint-research-centre.ec.europa.eu

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Authors

Stamatios Chondrogiannis

Julija Vasiljevska

Antonios Marinopoulos

Ioulia Papaioannou

Gianluca Flego

Abstract

This report reviews some of the main projects on developing flexibility markets in Europe. The analysis focuses on cases aiming primarily to improve the provision of local flexibility services to Distribution System Operators (DSOs) through market-based instruments, and it considers the role of regulation in promoting the use of flexibility. Specifically, the following projects/markets are reviewed (the countries in which they have been developed are in parentheses):

- sthlmflex (Sweden),
- IntraFlex (United Kingdom),
- NorFlex (Norway),
- the Grid Operators Platform for Congestion Solutions (GOPACS) (the Netherlands),
- enera Flexmarkt (Germany),
- GB flexibility tenders by DSOs (United Kingdom),
- ENEDIS flexibility tenders (France).

The following aspects are examined in more detail: pre-qualification procedures, the specification of flexibility products, the trading mechanism, and activation and settlement. Whenever possible, information on traded volumes and prices has been gathered. Common characteristics of and differences between the local flexibility markets reviewed are discussed, while current trends and challenges for the future are identified.

The main finding of this analysis is that flexibility procurement for distribution network operation and planning is under development at various degrees of maturity among European countries, with a variety of methods employed. The regulatory framework for DSOs' revenues and the specific national situation of the distribution network both play significant roles in the level of flexibility procurement and in the preferred method(s). Market-based procurement of flexibility services by DSOs is still a niche practice in most countries. From the cases reviewed in this report, three countries (France, the Netherlands and the United Kingdom) take a business-as-usual approach to market-based procurement, two (Norway and Sweden) have developed pilot projects and, in Germany, a rule-based approach was, in the end, chosen as the main option. Nevertheless, even among those countries where market-based procurement can be considered to have reached a business-as-usual stage, there are significant discrepancies in terms of volumes procured and level of market maturity. Distribution network operators in the United Kingdom systematically procure local flexibility services and in increasing volumes each year, backed by a supportive regulatory mandate. In the Netherlands, GOPACS is a well-established mechanism, and the recent collaboration with EPEX SPOT is expected to further increase the liquidity in the market for flexibility services provided by assets in the distribution system. On the other hand, the flexibility tenders in France have produced rather disappointing results so far, owing to, among other things, more attractive business alternatives for flexibility service providers (e.g. participation in the capacity remuneration mechanism), the design of the tenders (specific, non-divisible products) and the price caps imposed by the major DSO in France (ENEDIS).

1. Introduction

The decarbonisation of the energy system will bring a significant, perhaps even pervasive, electrification of end-uses in all consumer categories and in a number of sectors, such as in heating and cooling and in transport. In conjunction, the proliferation of variable renewable energy sources (RESs) – the main technological option for decarbonising the energy system – is already exerting stress on transmission and distribution networks. Considerable investments in network infrastructure are expected to be required in the next decades to accommodate these trends (see, for example, (Deloitte, et al., 2021; ENTSO-E, 2021).

On the other hand, the diffusion of distributed energy resources (DERs), digitalisation, and policy and regulatory impetus set active customers ([1]) at the centre of the energy transition, which offers significant opportunities for 'smarter' planning and operation of power systems.

The role and value of demand-side flexibility in enabling cost-efficient grid utilisation while enabling large-scale integration of renewable energy into the system has been recognised and included in a set of policy documents as part of the third energy package ([2]) adopted in 2009. More specifically, the electricity directive (Directive 2009/72/EC) ([3]) uses the term 'demand-side management', mainly in the context of security of supply. In 2015, the role and value of demand-side flexibility was further strengthened within the energy union package ([4]) and in the Commission communication on a new deal for energy consumers (European Commission, 2015), which places citizens at the core of the EU energy strategy and empowers them to actively participate in the energy market. The clean energy for all Europeans package ([5]), which was proposed in 2016 and entered into force in 2019, consists of a set of legal acts among which is the renewable energy directive (Directive (EU) 2018/2001) ([6]), in which paragraph 24 calls for 'additional investments in various sources of flexibility (e.g. demand response and flexible generation) to allow for cost-effective integration of additional renewable energy capacity'. Furthermore, the energy efficiency directive (Directive (EU) 2018/2002) ([7]), paragraph 2, endorses the view that 'energy efficiency and demand-side response can compete on equal terms with generation capacity'.

Article 3 of the electricity regulation (Regulation (EU) 2019/943) ([8]) demands adoption of market rules that will 'facilitate the development of more flexible generation, sustainable low carbon generation, and more flexible demand' and calls for incentives for distribution system operators (DSOs), 'for the most cost-efficient operation and development of their networks including through the procurement of flexibility services'. Article 53 of the regulation goes even further by establishing a new entity, the EU DSO, with one of its tasks (defined in Article 55) to 'facilitate demand-side flexibility and response and distribution grid users' access to markets'. In parallel, the electricity market directive (Directive (EU) 2019/944) ([9]) promotes active participation of consumers – individually or collectively via energy community schemes – in all energy markets. More specifically, and as regards the context of this study, Article 32 of the electricity market directive highlights the importance of the development of an adequate regulatory framework 'to allow and provide incentives to distribution system operators to procure flexibility services, including congestion management in their areas, in order to improve efficiencies in the operation and development of the distribution system'.

In the meantime, and even before some of these policy documents came into force, the Council of European Energy Regulators (CEER) alluded to the value of deploying and using flexibility at both transmission and distribution grid levels (CEER 2016, 2018). The most recent publication in this regard focuses on the DSO procedures for the procurement of flexibility (CEER, 2020a). On a similar note, in 2019, five European

([1]) According to the electricity directive (Directive 2009/72/EC), '"active customer" means a final customer, or a group of jointly acting final customers, who consumes or stores electricity generated within its premises located within confined boundaries or, where permitted by a Member State, within other premises, or who sells self-generated electricity or participates in flexibility or energy efficiency schemes, provided that those activities do not constitute its primary commercial or professional activity.'

([2]) https://energy.ec.europa.eu/topics/markets-and-consumers/market-legislation/third-energy-package_en

([3]) Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC.

([4]) https://energy.ec.europa.eu/topics/energy-strategy/energy-union_en

([5]) https://energy.ec.europa.eu/topics/energy-strategy/clean-energy-all-europeans-package_en

([6]) Directive (EU) 2018/ 2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources.

([7]) Directive (EU) 2018/2002 of the European Parliament and of the Council of 11 December 2018 amending Directive 2012/27/EU on energy efficiency.

([8]) Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast).

([9]) Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast).

organisations (European Distribution System Operators (E.DSO), the European Federation of Local and Regional Energy Companies (CEDEC), the European Association for the Cooperation of Transmission System Operators for Electricity (ENTSO-E), Eurelectric and GEODE) joined forces and published their views in a transmission system operator (TSO) / DSO data management report focusing on TSO/DSO coordination in congestion management and balancing using flexibility (CEDEC et al., 2019).

In December 2019, the European Commission adopted the European Green Deal ([10]) – an ambitious plan in which decarbonisation of the energy sector plays a key role and citizens are at its heart. As part of this plan, the EU strategy for energy system integration ([11]) was adopted in 2020, which promotes better integration across multiple energy carriers to 'unlock additional flexibility for the overall management of the energy system and thus help to integrate increased shares of variable renewable energy production'.

Large-scale deployment of demand-side flexibility necessitates digital infrastructure to allow secure and reliable data access and exchange between different market players. In 2020, the EU adopted a policy document on shaping Europe's digital future ([12]) as part of the EU digital strategy, which highlights the importance of the twin challenge of the green and digital transitions to support the implementation of the EU Green Deal. The most recent Fit for 55 package ([13]) embraces the revision of Europe's climate, energy and transport-related legislation that was undertaken to align current laws with the 2030 and 2050 ambitions. As part of this package, and for Europe to be able to deliver the EU Green Deal, revisions have been proposed for both the renewable energy directive and the energy efficiency directive to align them with the EU's increased climate ambition. The proposal for a revised renewable energy directive (European Commission, 2021a) ([14]) reiterates the importance of having national regulatory frameworks that:

> *do not discriminate against participation in the electricity markets, including congestion management and the provision of flexibility and balancing services, of small or mobile systems such as domestic batteries and electric vehicles, both directly and through aggregation.*

Similarly, the proposal for a revised energy efficiency directive (European Commission, 2021b) strengthens the value of demand-side flexibility in view of the energy efficiency first principle ([15]) and calls on Member States to:

> *take into account potential benefits from demand-side flexibility in applying the energy efficiency first principle and where relevant consider demand response, energy storage and smart solutions as part of their efforts to increase efficiency of the integrated energy system.*

The European Commission's recent plan REPowerEU ([16]) takes a stance on the recent geopolitical and energy market developments and calls on EU Member States to accelerate the clean energy transition and increase Europe's energy independence. Supported by a set of financial and legal measures, REPowerEU commits to massively scaling up the deployment of RES and to accelerating the electrification of the end-use sector – both of which will produce significant opportunities for distributed flexibility in the future.

Figure 1 summarises the EU energy policy documents relevant to flexibility. It is noted that, while all of these policy documents envisage and contribute to the development of flexibility in the power (and, in more general terms, the energy) system, they do not provide specific provisions for the architecture of local flexibility markets.

([10]) https://ec.europa.eu/clima/eu-action/european-green-deal_en

([11]) **Error! Hyperlink reference not valid.**https://energy.ec.europa.eu/topics/energy-systems-integration/eu-strategy-energy-system-integration_en

([12]) **Error! Hyperlink reference not valid.**https://ec.europa.eu/info/strategy/priorities-2019-2024/europe-fit-digital-age/shaping-europe-digital-future_en

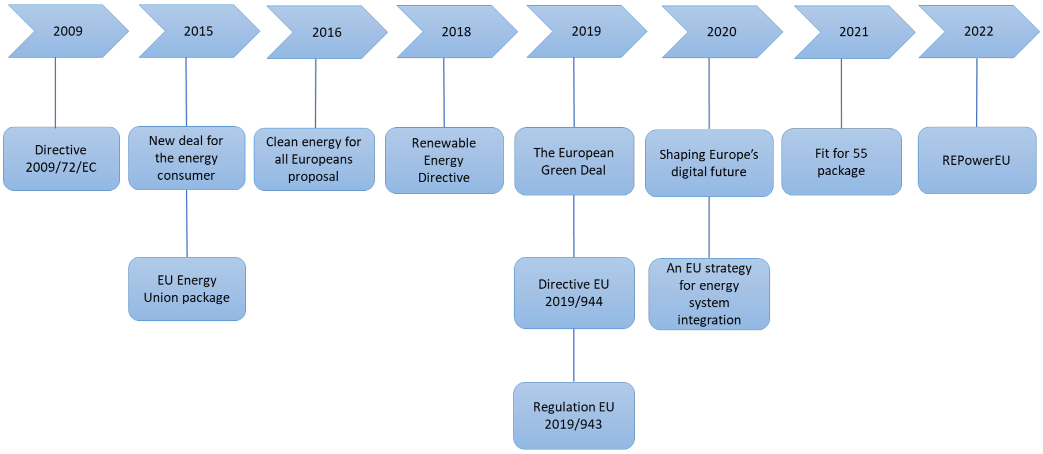
([13]) https://www.consilium.europa.eu/en/policies/green-deal/fit-for-55-the-eu-plan-for-a-green-transition/

([14]) EUR-Lex – 52021PC0557 – EN – EUR-Lex (europa.eu)

([15]) The "energy efficiency first principle" means taking utmost account of cost-efficient energy efficiency measures in shaping energy policy and making relevant investment decisions.

([16]) https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal/repowereu-affordable-secure-and-sustainable-energy-europe_en

Figure 1: Energy policy documents with reference and relevance to flexibility



Source: JRC analysis.

1.1. Scope of this report

This report examines the emerging market-based flexibility procurement initiatives by DSOs, given that Article 32 of the EU electricity market directive defines market-based procedures as the default option for procurement of such services by DSOs, except in cases in which national regulatory authorities establish that this procurement method would not be effective or efficient or would be severely market distortive ([17]).

In this report, the term 'local flexibility markets' refers to all types of market-based procurement of flexibility services by DSOs, irrespective of their architecture (e.g. spot markets close to real time as opposed to long-term tenders) and operational status (e.g. business as usual as opposed to pilot projects). In all of the markets reviewed, the DSO(s) is (are among) the buyer(s) of flexibility services, but other players (e.g. the TSO or balance responsible parties (BRPs)) may or may not, depending on the case, also procure flexibility services. The types of possible flexibility services and buyers are summarised in **Table 1**.

Table 1: Possible flexibility services procured by different actors in the local flexibility markets reviewed

Type of flexibility	**Buyer of flexibility services**		
	DSO	**TSO**	**BRPs**
Congestion management (distribution system)	X		
Voltage control (distribution system)	X		
Reliability enhancement (distribution system)	X		
Network deferral (distribution system)	X		
Frequency control (balancing)		X	
Congestion management (transmission system)		X	
Portfolio optimisation			X

Source: JRC analysis.

First, the report investigates the role of regulation in promoting the use of flexibility, particularly at distribution network level, in six European countries where local flexibility markets have been developed. This investigation

([17]) Section 3.2 provides a detailed overview of the different possible procurement methods of flexibility services by DSOs (rules-based procurement, flexible connection agreements, tariff structures and market-based procurement).

includes the DSO revenue model to better understand the incentives provided to the DSO for more cost-efficient operation and planning of the distribution grid, the role of independent aggregators and the financial responsibility associated with independent aggregators on balancing and on tranfer of energy (ToE).

Given that very few local flexibility markets currently have a business-as-usual status, pilot projects are also examined. More specifically, the following initiatives are reviewed in detail:

— the NODES market platform and its applications in the local flexibility market projects of NorFlex (Norway), sthlmflex (Sweden) and IntraFlex (the United Kingdom);

— the Grid Operators Platform for Congestion Solutions (GOPACS) (the Netherlands);

— the enera Flexmarkt (Germany);

— the UK flexibility tenders;

— the ENEDIS flexibility tenders (France).

The cases analysed were chosen based on a combination of the level of maturity, the public information available, size, results and the insights provided. Further work is required to look into new initiatives from all over Europe, and particularly initiatives developed in the context of some ongoing major Horizon projects on the topic (we are referring here to CoordiNet ([18]), Platone ([19]), OneNet ([20]) and Interrface ([21])). When future trends are discussed in this report, insights from these projects have also been considered, subject to their level of progress.

For the analysis of the aforementioned initiatives, extensive desktop research was undertaken, complemented by a survey and structured interviews with relevant stakeholders (i.e. market platform and network operators). Following this, the aforementioned projects were summarised focusing on pre-qualification procedures, the design of flexibility products, the trading of flexibility (the architecture of market-based procurement), and activation and settlement procedures. Based on this assessment, common themes and major differences were identified and are discussed in this report. In addition, key issues for the shaping of local flexibility markets in the future are discussed.

The structure of the report is as follows. In Chapter 2, more details on the methodology are provided. Chapter 3 presents deployment provisions that are relevant to flexibility in the national regulatory frameworks of the countries examined. Chapter 4 presents in detail the local flexibility markets examined. Chapter 5 provides a synthesis analysis of the local flexibility markets examined. Chapter 6 discusses critical issues in the development of local flexibility markets in Europe. Finally, Chapter 7 sets out the conclusions of the overall analysis.

([18]) https://coordinet-project.eu/
([19]) https://www.platone-h2020.eu/
([20]) https://onenet-project.eu/
([21]) http://www.interrface.eu/

2. Methodology

We first investigated the role of regulation in promoting the use of flexibility by performing extensive desktop research to better understand the DSO revenue models in the countries selected for our analysis, as well as the role of independent aggregators, including their balance and financial responsibility.

Furthermore, we examined real-life examples of local flexibility markets/projects in Europe in the same six European countries by complementing the in-depth desktop research with a survey and structured interviews with relevant stakeholders.

Overall, feedback from the following entities was received (the relevant local flexibility markets are indicated in parentheses):

- NODES (NODES market platform)
- Svenska kraftnät (sthlmflex)
- Ellevio (sthlmflex)
- Vattenfall Eldistribution (sthlmflex)
- Western Power Distribution (IntraFlex)
- Agder Energi (NorFlex)
- EWE NETZ GmbH (enera Flexmarkt)
- EPEX SPOT (enera Flexmarkt)
- ENEDIS (ENEDIS flexibility tenders)
- Piclo Flex (UK flexibility tenders)
- Energy Networks Association (ENA) power networks (UK flexibility tenders).

In addition, feedback on GOPACS was received from an expert previously working at TenneT.

The main survey targeted all flexibility markets in general, with certain, more specialised, markets specific to each project also targeted. The questions of the former can be found in Annex 1.

The analysis of the local flexibility markets was undertaken according to the following dimensions:

- pre-qualification procedures;
- the design of flexibility products;
- the trading of flexibility (procurement architecture);
- activation and settlement procedures;
- results and lessons learnt.

It is noted that a similar approach was also followed in other work on the subject (see Frontier Economics and ENTSO-E, 2021). The remainder of this chapter sets out a more detailed presentation of the key questions investigated for each of the aforementioned dimensions.

2.1. Pre-qualification procedures

The pre-qualification procedures imposed on flexibility assets and service providers were investigated with the purpose of assessing the level of complexity and any potential barriers to their participation in the local flexibility market. The investigation was divided into technical aspects (e.g. pre-qualification tests and other processes) and compliance with the necessary regulatory, legal and/or financial requirements.

2.2. Design of flexibility products

The technical specifications of the traded flexibility products were investigated with the final aim of assessing the level of convergence among the different markets. Particular aspects that were examined included:

- the flexibility service that the products targeted – flexibility services include network deferral, congestion management, enhancement of network resilience and reactive power/voltage control;

- whether the flexibility products had only an activation component or also had an availability component;
- the direction of the traded flexibility (upwards, downwards or both ([22]));
- the procurement horizon and the activation period of each flexibility product;
- the minimum bid size and whether or not bids were divisible;
- other technical specifications associated with the design of each flexibility product, such as notice period, time to full activation, ramping limits and/or recovery rules;
- whether price is freely formed or predefined by the buyer network operator, and whether or not price caps exist.

2.3. Market architecture

The subject of this particular dimension is how, and between which parties, flexibility is traded. Particular aspects that were examined included:

- the involved parties – although the focus is on local flexibility markets for the provision of services to DSOs, the market platform can be used for the provision of services also to TSOs; in this case, of particular interest was the relevant priority rules between the different network operators;
- the operational security coordination mechanisms (if any) between different network operators for avoiding the activation of flexibility causing security violations to parts of the network outside the responsibility of the buying network operator;
- coordination (if any) with the wholesale energy market – flexibility service providers (FSPs) may also trade their flexibility to market parties (i.e. to BRPs) and so we consider the coordination of flexibility provided to network operators, with a particular interest in the mechanisms and responsibilities for avoiding double counting of the same flexibility activation;
- the temporal form of trading and, in particular, differentiation between long-term and short-term trading;
- the time span between the point when the buyer network operator declares the requested volumes of flexibility and the time of flexibility activation, as well as the gate closure time (GCT) for FSPs declaring their offers;
- the market time unit (MTU) ([23]);
- the spatial organisation of trading, as well as differentiation between portfolio bidding and separate flexibility asset bidding (unit bidding);
- whether spot trading takes place (auctions) or different forms of continuous trading are followed;
- the clearing mechanism and, in particular, whether only price or also other criteria are employed for the evaluation of flexibility offers;
- the price formation mechanism (pay-as-clear, pay-as-bid or predetermined price set by the buyer network operator);
- access to information by FSPs regarding the existence of price caps.

2.4. Activation and settlement procedures

On this subject, we first reviewed the communication means for the activation of flexibility services. The assessment of the settlement procedures included the following topics:

- the measurement period and the settlement period;
- the type of measurements employed for the settlement (i.e. whether measurements from the connection meter only were allowed or measurements from the flexibility assets' sub-meters were also permitted for the settlement);

([22]) Upwards flexibility is the reduction of consumption or an increase in generation against a baseline, while downwards flexibility is the opposite (i.e. an increase in consumption or a decrease in generation against a baseline).

([23]) The MTU is the period for which the flexibility product price is established.

- the employed baseline against which the settlement took place, with the main differentiation being between self-declared baselines by the FSPs and a centrally defined baseline by the market operator or the buying network operators;
- remuneration rules under partial delivery of flexibility, including whether penalties were imposed or not;
- the contractual relationships between FSPs and respective BRPs when the two entities were different (i.e. in the case of independent aggregators ([24])) – two issues were investigated here in more detail: first, which market party undertakes balance responsibility and, second, whether the FSP compensates the supplier for the energy pre-bought by the latter in the wholesale market ([25]).

2.5. Results and lessons learnt

The results gained thus far from the flexibility markets studied have been collated, including the flexibility volumes activated and prices. The major lessons learnt were analysed and, during the structured interviews, the projects' stakeholders were asked about their general views regarding the evolution of flexibility markets in Europe, along with their future plans.

([24]) According to the electricity market directive, an 'independent aggregator' is a market participant engaged in aggregation who is not affiliated to the customer's supplier.

([25]) A comprehensive presentation of the issues pertaining to the contractual relationships between independent aggregators and BRPs can be found in Schittekatte et al. (2021).

3. Review of the regulatory framework on flexibility

This chapter looks into the role of regulation in promoting the use of flexibility, particularly at distribution network level, in the six European countries in which the local flexibility markets examined were found: France, Germany, the Netherlands, Norway, Sweden and the United Kingdom. More specifically, we provide a closer look into the DSO revenue model to better understand the incentives provided to DSOs for more cost-efficient operation and planning of the distribution grid. Additionally, we investigate the extent to which the countries analysed have already deployed or are in the process of deploying distributed flexibility at a larger scale, including by identifying major barriers to the development of local flexibility markets. In this context, we analyse and discuss a set of relevant issues, including existing solutions to flexibility procurement, the role of independent aggregators, and balancing responsibility and compensation mechanisms associated with independent aggregators.

3.1. Distribution system operator revenue models

This section provides a general overview of the regulatory frameworks for DSOs in the selected EU countries and, more specifically, discusses the types of regulations adopted, including incentives for more efficient operation and planning of the distribution grids. The types of regulations that DSOs are subject to may influence their choice between the use of traditional solutions, such as network reinforcement or flexible solutions (flexible connections, market-based procurement of flexibility, etc.), or a combination of different types of solutions. In this context, we want to examine whether or not the adopted regulatory mechanism in each country incorporates the value of flexibility in the DSO revenue model, or at least does not present a barrier to flexibility deployment.

Furthermore, this section sheds light on the types of incentives used in each country to promote and facilitate innovation in the operation and planning of the distribution grids.

The following topics are discussed for each of the countries selected for our analysis:

- the type of regulatory mechanisms in place (rate of return, incentive regulation (revenue/price cap), etc.);
- the main elements for the determination of the DSO's revenue – the treatment of capital expenditure (CAPEX) and operational expenditure (OPEX), the duration of the regulatory period, quality (performance- or output -based) regulation, efficiency benchmarking, etc.;
- innovation incentives – the treatment of research and development (R & D) costs, regulatory sandboxes, the regulatory impetus for market-based procurement of flexibility, etc.

Table 2 presents an overview of the DSO regulatory mechanisms in the selected countries, including the main elements used for the calculation of the DSO's revenues and the type of innovation incentives used for promoting more cost-efficient operation and planning of the distribution system.

First, we look at the type of regulation each of the countries analysed has implemented as a way of granting DSOs with an adequate return for maintaining and expanding their infrastructure, while protecting electricity consumers from high network tariffs. As we can see from Table 2, all of the EU countries analysed have opted for incentive regulation with revenue/price cap schemes and efficiency benchmarking ([26]). Under such a scheme, the regulator sets the overall revenue that the DSO can earn (revenue cap) or the price it can charge (price cap) for the price control (regulatory) period, considering the expected efficient cost during the regulatory period, based on the network operator's own costs but also on the performance of other comparable DSOs (yardstick competition). In this sense, the DSO can either benefit from cost savings or receive reduced revenue allowance for not reaching the target values. Additionally, only a few outputs, such as quality and reliability of supply, may account for an increase or decrease of the revenue or price cap, thus incentivising the DSOs to improve quality of service.

Under revenue (or price) capping schemes, as costs are estimated for each regulatory period (typically a few years ahead), DSOs may be incentivised to reduce costs as early as possible rather than considering the long-term effect of the investment. This can limit investments in infrastructure, which normally have a payback time longer than the regulatory period (Armstrong and Sappington, 2006). To address this, regulators could treat OPEX and CAPEX differently (Müller, 2012). Allowed revenue for the DSO is calculated as the sum of estimated OPEX, depreciation and return on capital. Return on capital represents the opportunity cost of investing in the network rather than in other activities. Thus, while forecast OPEX is added directly, CAPEX is capitalised in the

([26]) Efficiency benchmarking involves assessing the operators' individual costs against the services they provide and determining each operator's cost efficiency compared to other operators.

regulatory asset base (RAB) and a rate of return is applied to the RAB. Although this can be effective in incentivising infrastructure investment, it can result in a bias towards CAPEX. An alternative to this approach is total expenditure (TOTEX), which allows the DSO to choose between OPEX and CAPEX, or an efficient mix of both, to meet network demands (Ofgem, 2009).

Table 2: DSO revenue models

Elements for calculation of model	**France**	**Germany**	**Netherlands**	**Norway**	**Sweden**	**United Kingdom**
Regulatory mechanism	Incentive regulation (revenue cap)	Incentive regulation (revenue cap)	Incentive regulation (price cap)	Incentive regulation (revenue cap)	Incentive regulation (revenue cap)	Incentive regulation (revenue cap)
Cost examination	TOTEX (*)	TOTEX	TOTEX	TOTEX	TOTEX	TOTEX
Regulatory period	4 years (2021–2025)	5 years (2019–2023)	3–5 years (2022–2026)	3–5 years (2018–2022)	4 years (2020–2023)	8 years (2015–2023)
Efficiency benchmarking	No	Yes (yardstick)	Yes (yardstick)	Yes (yardstick)	Yes (yardstick)	Yes (yardstick)
Quality incentive	Yes	Yes	Yes	Yes	Yes	Yes
Innovation incentives	— Through tariffs (R & D OPEX not subject to efficiency requirements) — Regulatory sandboxes	— Efficiency bonus passed through tariffs — Regulatory sandboxes	Indirect (**)	Pass-through costs (***)	— Indirect (**) — Pilot regulation on different tariff structures	— Innovation stimulus and price control package (RIIO (****) model) — Flexibility innovation programme

(*) For non-network expenditures.
(**) Innovation as a means to reach other goals.
(***) Under certain conditions.
(****) Revenues = innovation + incentives + outputs.
Source: JRC analysis.

Another relevant aspect is the duration of the regulatory period, which is critical in determining the strength of the incentive (Armstrong and Sappington, 2006). While longer regulatory periods provide more stability and certainty for network operators and customers, as well as stronger efficiency incentives, they can create high uncertainty owing to the level of assumptions and forecast required during the price control period. This was recognised by the UK regulator and, as a result, the regulatory period for the new price control (RIIO-2) has been shortened. On the other hand, excessively short regulatory periods may lead to under-investments and may undermine the strength of the efficiency incentive (Balázs, 2009).

Finally, rather than using the firm's expected costs to set the revenue (or price) cap, the regulator can use the costs of similar firms as a benchmark, an approach called yardstick competition. By comparing similar firms, the regulator can deduce the DSO's achievable costs, thus reducing the degree of information asymmetry between the firm and the regulator, which can provide additional efficiency incentives for the revenue (or price) capping (Shleifer, 1985; Hellwig et al., 2019).

All of the European countries analysed in this study have adopted a TOTEX approach, which allows the DSO to choose OPEX or CAPEX or a mix of both to meet network demands, which is the opposite of non-TOTEX approaches, which may direct network expenditure towards CAPEX- or OPEX-based solutions. In this way, DSOs are incentivised to choose the most efficient combination of resources to achieve several regulatory aims using, for example, less capital-intensive innovative expenses and higher OPEX in the short term (e.g. flexibility procurement), instead of traditional network investments (CEER, 2022). The following subsections provide a more detailed view on the DSO revenue model in each of the countries examined.

3.1.1. France

The French regulatory authority Commission de Régulation de l'Énergie (CRE) sets a revenue cap that is annually adjusted during each 4-year regulatory period (currently 2021–2025). Each year's revenues are set *ex ante* and mainly consist of an estimation of OPEX and a return on the RAB. While OPEX is subject to incentive regulation, CAPEX is subject to rate of return regulation, which can create incentive bias. As a result, the regulator has decided to differentiate between the way network and non-network expenses are treated – while network expenditures are treated as before, for non-network expenditures, OPEX and CAPEX are subject to the same incentives. In addition, the French regulator has strengthened the incentive for quality of service, particularly regarding connection times, and it has set a goal for the largest French DSO (ENEDIS) to shorten its connection times by an average of 30 % by 2024 (CRE, 2021a).

As for R & D incentives, each network operator proposes an annual R & D budget at the beginning of each regulatory period, which is then subject to approval by the regulator. Deviations from planned R & D expenditures are recovered entirely through adjustments to the revenue allowance in the following years, subject to evidence sent by the DSO to the regulator to justify and account for the difference from the planned budget. It is interesting to note here is that, owing to the different schemes applied to OPEX and CAPEX, the regulator has observed that investments that produce a reduction in CAPEX (e.g. demand-side management and storage) with a less than proportional increase in OPEX may be penalised – a case particularly relevant for smart grid investments, and also applicable to flexibility projects. As a result, R & D OPEX is not subject to efficiency benchmarking. In addition, smart grid projects with OPEX higher than EUR 3 million can recover justified cost overruns following adjustments in the revenue cap (CRE, 2021a).

In 2020, the French regulator (CRE) published its decision for implementation of a regulatory sandbox, followed by two application periods, in 2020 and 2021, respectively (CRE, 2021b). During the first application period, 20 projects (out of 42) were granted a regulatory sandbox and the main topics included the integration of electric vehicles (EVs) into the power system, the participation of storage and the provision of flexibility services in the market, innovative network tariffs and power-to-gas applications (An et al., 2021). The second application period was September 2021–January 2022. In addition, the Ministry for Ecological Transition may also grant regulatory exemptions from the conditions for network access and use in its areas of competence. As of July 2021, the ministry had granted exemption to four projects, one being the ReFlex project, led by the largest French DSO (ENEDIS). Further details about this project can be found in Section 3.2.3.

3.1.2. Germany

The German regulatory authority (Bundesnetzagentur - BNetzA) sets caps on firms' revenues during each regulatory period (currently 5 years: 2019–2023). The revenues allowed are set *ex ante* for the whole regulatory period and are adjusted yearly based on outputs that account for network reliability and quality of supply (Matschoss, et al. 2019). Furthermore, the regulatory authority applies efficiency benchmarking by increasing or reducing the revenue cap when the reliability of supply deviates from the average of all comparable DSOs ([27]) each year (weighted averages of key figures, e.g. duration and frequency of interruptions of supply are calculated for all comparable DSOs for the last 3 years). To further incentivise innovation, in 2016, the regulator introduced a super efficiency bonus scheme, which provides those DSOs with a 100 % efficiency rating with a mark-up on the revenue cap (Federal Ministry for Economic Affairs and Climate Action, 2016). The mark-up amounts to a maximum of 5 % and is evenly distributed over the regulatory period (Matschoss et al., 2019).

Incentives for R & D in new technologies are mainly provided by large funding programmes under the Federal Government, leaving the regulator with a limited role in this regard. However, an incentive mechanism exists in the form of an adjustment to the revenue allowance, meaning that, every year, network operators can partially

([27]) The standard procedure applies to DSOs with a customer base larger than 30 000 and a simplified procedure applies to small DSOs of up to 30 000 customers (182 out the 879 German DSOs are subject to the standard procedure).

recover R & D project expenses undertaken in that year by increasing the revenue allowance by 50 % of the total costs not covered by public funding (Federal Ministry for Economic Affairs and Climate Action, 2016)]. R & D costs already included in the initial revenue caps are not eligible for adjustment. For a project to be eligible, it must be included in a research funding programme approved by a regulatory authority or governmental body (e.g., the Federal Ministry for Economic Affairs and Climate Action).

To further facilitate the transfer of technology and innovation for the integration of large-scale renewable energy, the Federal Ministry for Economic Affairs and Climate Action launched the implementation of regulatory sandboxes for energy transition (technology readiness levels 3–9), as part of the seventh edition of the energy research programme (Federal Ministry for Economic Affairs and Energy, 2020). Regulatory sandboxes for the energy transition were set to last from 2019 to 2022 with allocated funding of up to EUR 100 million per year. Topics range from sector coupling and hydrogen technologies to energy storage in the electricity sector and energy-optimised urban districts. Projects granted a regulatory sandbox can have a duration of up to 5 years.

3.1.3. Netherlands

The Dutch regulator adopted an incentive regulation using a price cap based on TOTEX with network operational efficiency (reduced network losses) and a quality incentive, and using yardstick competition for cost-efficiency benchmarking. This approach provides DSOs with an opportunity to select the most efficient mix of expenses: OPEX (e.g. procuring flexibility) and CAPEX (i.e. conventional grid reinforcement). However, DSOs that spend more on CAPEX (i.e. timely investment in network reinforcement) may perform better than the benchmark, whereas DSOs that procure flexibility to manage congestion with relatively high OPEX may perform worse (Anaya and Pollitt, 2021). Therefore, it is critical that the regulation is fit for purpose and that the DSOs properly factor in the value of flexibility in their network investment decisions.

With respect to R & D spending, the Ministry of Economic Affairs together with other institutions is responsible for guiding the choice of the necessary projects and the implementation of funding programmes, such as the Topsector program ([28]). The regulatory sandboxes in the Netherlands between 2015 and 2018 were explicitly reserved for small emerging players in the energy arena, such as energy communities and homeowner associations, and focused mainly on decentralised energy production and peer-to-peer energy trading and supply. Following the advice of the Council of State, the Ministry of Economic Affairs and Climate decided to no longer run the scheme, partly because the new energy act should come into force in 2022 and because the decision on whether regulatory experiments should be part of it is still pending.

3.1.4. Norway

In Norway, the revenue cap is set annually based on a formula of 40 % cost recovery and 60 % cost norm resulting from benchmarking models based on the costs of other comparable DSOs in the country (yardstick competition). This ratio will change starting from 2023 to 30 % cost recovery and 70 % cost norm, which is expected to increase incentives for cost-efficiency.

Expenditures for R & D and pilot projects are added to the revenues allowed (with a maximum of 0.3 % RAB). The current R & D scheme for Norwegian DSOs was implemented on 1 January 2013, which allows specific and pre-qualified R & D project costs to be recovered directly through the grid tariff (i.e. outside the revenue cap regulation scheme); therefore, they are not included in the benchmarking. Three conditions must be fulfilled before the costs are accepted in this mechanism ([29]):

1. the R & D project should prove useful for grid operation / investments / planning;
2. it represents a maximum of 0.3 % of the DSO's RAB;
3. it needs to be approved by an external body (e.g. the Norwegian Research Council).

As of 2021, the Norwegian Energy Regulatory Authority (NVE-RME) has approved 215 projects as part of this scheme ([30]).

In addition, in 2019, the regulator developed a regulatory sandbox framework for pilot and demonstration projects (typically with technology readiness levels 5–8) ([31]). The main purpose of this framework is to facilitate

([28]) https://www.topsectorenergie.nl/en
([29]) https://www.nve.no/norwegian-energy-regulatory-authority/economic-regulation/incentive-scheme-for-r-d/
([30]) https://www.nve.no/reguleringsmyndigheten/bransje/bransjeoppgaver/finansieringsordning-for-fou/godkjente-prosjekter-i-rmes-finansieringsordning-for-fou/
([31]) https://www.nve.no/reguleringsmyndigheten/bransje/bransjeoppgaver/pilot-og-demonstrasjonsprosjekter/

the implementation of these projects in a controlled regulatory environment based on two basic principles: to provide information about current rules and regulations and to have a transparent derogation process. Since the adoption of the framework, there have been nine projects granted a derogation. Most of those projects aim to trial innovative solutions linked to flexibility, aggregation and network tariffs. The regulator has also granted a derogation to several TSOs that are willing to trial solutions related to the procurement of flexibility services but that are not able to commercially do so due to current requirements regarding bid size and composition.

3.1.5. Sweden

In Sweden, output-based incentives for reliability and quality of supply and efficient grid utilisation (assessed through network losses and average load factor) are integrated in the revenue cap, which is annually adjusted. In addition, an efficiency benchmarking model is used to estimate DSOs' specific potential for efficiency improvements. The benchmarking involves assessing DSOs' individual costs against the services they provide and determining each DSO's cost-efficiency compared with other DSOs. In the benchmarking process, the regulator compares the inputs (controllable OPEX) with the outputs (number of customers, high and low voltage electricity delivered, number of network stations, etc.) for each DSO (CEER, 2022). Furthermore, the regulator proposed a legislative amendment for the next regulatory period to include TOTEX in the efficiency benchmark instead of controllable OPEX only, which shows a movement towards higher cost-efficiency. In addition, the Swedish regulator has implemented a pilot regulation that allows all DSOs to test different tariff structures for specific customer categories to stimulate demand-side flexibility. In March 2022, the Swedish regulator launched a project to examine the conditions for setting up a regulatory sandbox scheme in the energy sector. A proposal for a model on regulatory sandboxes in the Swedish energy market will be presented at the end of the project in February 2023.

3.1.6. United Kingdom

The UK regulator Ofgem adopted, in 2013, an incentive (performance-based) regulation using a revenue cap, where revenues = innovation + incentives + outputs (RIIO). Under RIIO, firms are held accountable for delivering a high quality of service and cost-efficiency using output targets and TOTEX allowances, which means that a fixed proportion of a firm's total expenditure is added to the RAB, irrespective of whether it comprises CAPEX or OPEX. The revenue cap is adjusted yearly through performance and innovation incentives (Ofgem, 2010). Innovation is stimulated through a long regulatory period, an equal treatment of OPEX and CAPEX, and a focus on the delivery of outputs. There are three measures focusing on innovation – the network innovation allowance (NIA), network innovation competition (NIC) and the innovation roll-out mechanism (IRM) – which were introduced in 2015 for electricity distribution. The NIA is a yearly adjustment to the revenue allowance of network firms, which is used to finance small R & D and demonstration projects. This allowance is capped at 0.5–1 % of base revenues for each company, depending on the quality of its innovation strategy (Ofgem, 2011). NIC is a competition through which a few large development and demonstration projects run by the TSO and DSOs are selected for funding. Unlike the NIA, NIC focuses on projects aimed at granting environmental benefits. For a project to be funded (up to 90 %), the licensee must show how the innovation creates new knowledge and how it can be shared among network operators ([32]), while providing long-term value to network customers and environmental benefits (Ofgem, 2017). The IRM is an incentive that works by adjusting allowed revenues to fund the roll-out of trialled innovations if they have environmental benefits and provide value for money for consumers. However, the operator cannot get commercial benefits from this roll-out within the price control period to avoid financing investments that should be made under a business-as-usual status by the company (Ofgem, 2015).

The new RIIO price control framework will start in April 2023 and includes several modifications, including (Ofgem, 2018):

- a shortening of the price control length from 8 to 5 years, as, in the current regulatory period, the high uncertainty in the energy sector generated unreliable assumptions and forecasts, which led to allowances being set too high and performance targets being set too low;
- an increase in innovation delivered under a business-as-usual status while keeping the innovation stimulus package;

([32]) Data about projects supported by NIC and NIA mechanisms can be found on the ENA Smarter Networks Portal (https://smarter.energynetworks.org/).

— an overall simplification of the price control, especially regarding how outputs and costs are set.

In addition, the UK government (i.e. the Department for Business, Energy and Industrial Strategy) has recently launched the flexibility innovation programme ([33]), which is part of the department's net zero innovation portfolio and it seeks to enable large-scale widespread electricity system flexibility through smart, flexible, secure and accessible technologies and markets. Markets for flexibility and unlocking the value of flexibility is one of the central themes of the programme.

Large-scale deployment of flexibility services is also one of the focus areas of the open networks programme ([34]) which was set up in 2017 and is run by the ENA ([35]). As part of this programme, the United Kingdom's six distribution network operators (DNOs) ([36]) have made a strong commitment to increasing the use of competitive third-party flexibility services. More information on the open networks programme can be found in Section 4.7.

In 2017, a regulatory sandbox framework had already been developed by Ofgem, with the aim of supporting innovators who already (or intend to) operate in a regulated energy market in delivering trials or entering the market with a new product or service for energy consumers. Some of the topics of the projects granted derogation under this framework include trials linked to the development of new price methodologies for facilitating investment in on-street EV charge point infrastructure, for which reinforcement costs may be a barrier to deployment; trading of domestic flexibility in the balancing mechanism; peer-to-peer trading; etc ([37]).

3.2. Solutions to flexibility procurement

The electricity market directive granted DSOs an extended role by introducing access rights for end-users to sell flexibility (both upwards and downwards), directly or through aggregators or citizen energy communities. In this context, DSOs are empowered to take a more active role both as buyers of distributed flexibility and to facilitate others' use of flexibility resources in their own networks to enable system-wide benefits. Article 32 of the electricity market directive states that DSOs:

> *shall procure flexibility services in accordance with transparent, non-discriminatory and market-based procedures unless the regulatory authorities have established that the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion.*

Furthermore, this directive states that 'DSOs shall cooperate with transmission system operators for the effective participation of market participants connected to their grid in retail, wholesale and balancing markets'.

According to CEER, DSOs can access flexibility through (1) rules-based approaches, (2) flexible connection agreements, (3) tariff structures or (4) market-based procurement, or through a combination of these options (CEER, 2020a). In all cases, flexibility should be seen not as an end but rather as a tool to operate grids more efficiently while at the same time contributing to managing the ongoing challenges due to growing integration of renewable generation. The choice of measures as alternatives to traditional network reinforcement is driven by a plethora of factors, among them the national regulatory framework in place. More specifically, the choice is affected by the incentives for DSOs to more cost-efficiently operate and plan their networks, how CAPEX versus OPEX are treated in the regulatory model, if there are any efficiency requirements and how R & D-related costs are incorporated into the DSO revenue model (see Section 3.1). In addition, several approaches to accessing flexibility often co-exist and are linked, for example a flexible connection agreement coupled with a (rebated) interruptible tariff, which makes it more difficult to assess different solutions when facing a network constraint (e.g. congestion management). In this context, one issue that may arise is the co-existence of different solutions (namely market- versus non-market-based solutions) and whether (or not) one type of solution may hinder the deployment of another. For example, the advent and wider adoption of smart home technology and smart metering systems will further the possibilities regarding demand response; this in turn will help consumers to be more price-responsive and will increase the value of implicit flexibility in view of growing levels of variable renewables and the electrification of other end-user sectors (e.g. transport and

([33]) https://www.gov.uk/government/publications/flexibility-innovation
([34]) https://www.energynetworks.org/creating-tomorrows-networks/open-networks/
([35]) The ENA is an industry body representing the companies that operate the electricity wires, gas pipes and energy system in the United Kingdom and Ireland.
([36]) The United Kingdom's six DNOs are Electricity North West, Northern Powergrid, SP Energy Networks, Scottish and Southern Electricity Networks, UK Power Networks and Western Power Distribution.
([37]) A full list of projects, including descriptions and additional information, can be found on Ofgem's website (https://www.ofgem.gov.uk/publications/regulatory-sandbox-repository).

heating). On the other hand, depending on the tariff structure, implicit demand response may increase, rather than reduce, the need for explicit (market-based) flexibility at a certain location in the network (e.g. wholesale spot prices dropping to zero or negative levels could trigger a surge in EV fast charging, which in turn could cause a local congestion problem) (Nordic Energy Research, 2021).

In the following subsections, we discuss in more detail three out of the four options mentioned by CEER, namely the tariff structure, including network connection charges (flexible connection agreements); the market-based procurement of flexibility; and, briefly, the rule-based approach to flexibility procurement, which has been adopted in Germany.

3.2.1. Network tariffs and connection agreements

Article 32, paragraph 1, of the electricity market directive calls for Member States to enable and incentivise DSOs to procure flexibility services. One way of doing this is through a more cost-reflective tariff structure, such as use-of-network tariffs and connection charges, both contributing to what is called implicit flexibility. More specifically, flexibility can be procured through static or dynamic network tariffs. If flexibility is contracted for a sufficient period through static network tariffs, necessary network reinforcements may be deferred/avoided, which may lead to an overall reduction of the DSO's costs in the long run and therefore to lower network tariffs for network users. However, if static time signals do not trigger the desired demand-side flexibility, the procurement of explicit flexibility – when the DSO explicitly procures flexibility from the customer or through an intermediary – may be a cost-effective alternative to network reinforcements. To this end, explicit flexibility procurement can have an impact on DSOs' cost structures and, as a result, on network tariffs. In this context, the cost of procuring flexibility could be included in the DSOs' regulated revenue and passed on to all network users.

Dynamic network tariffs are another instrument for responding to network constraints. In this sense, demand-side flexibility can be used to respond to dynamic network tariffs and to offer flexibility services requested by a network operator. As such, the interaction between these instruments needs to be carefully considered. Incentives for end-users to adopt dynamic network tariffs might be weakened by other factors, for example dynamic retail prices, particularly if the retail price and network tariffs are integrated into a single component in the electricity bill. Another aspect is the technological requirements linked to the adoption of dynamic network tariffs, such as smart meters and certain levels of automation, to allow flexibility provision. In this context, dynamic tariffs might be more applicable to larger customers and to those smaller customers with sufficient means for flexibility provision and automation. Evidence from the adoption of dynamic tariffs in Europe is rather limited; combining dynamic tariffs with explicit flexibility may further increase complexity and not deliver increased efficiency (CEER, 2020b; Eurelectric, 2021). In addition, from consumers' perspective, dynamic tariffs may raise concerns over transparency and price volatility.

In this context, this section provides a closer look at the network tariffs and connection charges in the countries selected for our analysis as a method of encouraging both DSOs to acquire and customers to provide flexibility services.

In Norway, a proposal to modify the current network tariff structure to low-voltage (LV) customers, including a new capacity-based tariff design, has been made (Eriksen and Mook, 2020). The proposal suggests that the energy charge can no longer include a proportion of the fixed network costs. Instead, it should reflect the cost of marginal losses in the network. Furthermore, in periods of network constraints, the energy charge should be set higher than the short-term marginal cost of utilising the network, to incentivise reduction in peak demand (e.g. via time-of-use (ToU) dynamic or static tariffs). Alternatively, short-term flexibility can be procured via a local flexibility market. Nevertheless, the introduction of such a price signal may add more complexity to the tariff design, which necessitates the alignment of the tariff design with the development of flexibility markets. In addition, the proposal includes changes to the current design of the fixed charge, based on a reasonable distribution of fixed network costs, and a differentiation according to the customer's demand for capacity. First changes in network tariff design into this direction were implemented in July 2022. In addition, DSOs in Norway also currently rely on interruptible tariffs, which grant a network customer a reduced tariff in return for allowing the DSO to interrupt or reduce the power consumption.

In Sweden, the regulator considers network tariffs as critical to the promotion of efficient use of the grid. However, in 2020, only 17 (out of 170) DSOs indicated offers for network tariffs with a power-based component to customers with a fuse size below or equal to 63 A. Nevertheless, power-based tariffs with time differentiation, by season and/or by time of day, are expected to become more common in view of the growing capacity of renewable energy in the grid and the electrification of the transport and industry sectors. As in the case of Norway, in Sweden some DSOs also use interruptible tariffs to respond to grid constraints in addition to other alternatives, such as the procurement of local production (e.g. Ellevio's agreement for 320 MW production availability by Stockholm Exergi) and temporary subscription rights (see also Section 4.2).

In the Netherlands, the regulatory framework on network tariffs offers limited opportunities in terms of flexibility provision. One of the main reasons is the lack of locational signals, given the use of a uniform capacity-based tariff for residential consumers introduced in 2009. In addition, change towards a more dynamic network tariff structure is not expected to take place in the coming years. According to a recent study (D-Cision and Ecorys, 2019), the implementation of dynamic network tariffs could add additional complexity to the current static tariff structure, increase administrative burden and require more complex regulation.

In Germany, the current regulatory framework (Section 14a of the Energy Industry Act) grants reduced network tariffs to LV network users (controllable loads) for adjusting their consumption, as a way of responding to network constraints. Nevertheless, the value of the discount is not regulated and varies considerably across DSOs (with an average reduction in network charges of 55 %, equivalent to 3.44 ct/kWh) (Bundesnetzagentur, 2019). Current revisions of Section 14a of the Energy Industry Act include the possibility of reduced network charges for producers and the introduction of flexible contractual arrangements. In addition, the current model adopted for procuring flexibility at transmission and distribution network level (Redispatch 2.0) follows a rule-based approach, where all energy sources, including renewables and combined heat and power above 100 kW, are obliged to provide their flexibility in return for a cost-based compensation.

In France, procurement of explicit flexibility and network tariffs are considered as two different and complementary ways of addressing network investment needs, while optimising grid operation and planning. ToU network tariffs are offered to medium-voltage (MV) customers with a capacity above 36 kW; they can choose between a static ToU and a dynamic ToU with different off-peak and peak time windows defined for each MV circuit. In addition, critical peak pricing for network tariffs is available to LV customers (with predefined peak and off-peak time windows communicated a day ahead). Most retailers follow the same ToU windows offered by the DSO for the energy tariffs. The largest DSO in France (ENEDIS) also includes flexible (conditional) connection agreements for MV producers and MV consumers, with the aim being to increase and accelerate the integration of RES and to optimise planning and the operation of its distribution grid.

In the United Kingdom, there is an ongoing reform of network access and charges (Ofgem, 2022)– launched at the end of 2018 – in view of wider policy developments, including the broader flexibility strategy, as well as transport and heat decarbonisation. This reform touches on various aspects related to network access and charges, including distribution use-of-system charges, and demand and generation distribution network connections.

In a nutshell, most EU countries are proceeding cautiously with the adoption of more dynamic network tariffs – mainly owing to associated increased complexity, lack of predictability, technological requirements and the risk of unfairness (i.e. customers unable to react to them may end up paying more unless the tariff is applied on a voluntary basis) (Eurelectric, 2021).

3.2.2. Rule-based approach to access distributed flexibility

A market-based approach for the procurement of flexibility at distribution level, as opposed to a rule-based approach, is still a niche practice in many European countries, where a cautious approach is seen. Germany is a prime example: driven by high costs for congestion management, mainly at transmission network level (the annual cost is above EUR 1 billion (AFRY, 2021), the German regulatory authority (Bundesnetzagentur) has revised the NABEG 2.0 regulation and introduced Redispatch 2.0 (effective since 1 October 2021). Redispatch 2.0 is a cost-based mandatory approach to solving network congestion problems by involving storage facilities, RES generators, and combined heat and power plants, as well as conventional units, all with installed capacity above 100 kW, at both transmission and distribution level. To be able to fulfil the obligations under Redispatch 2.0 while reducing the overall costs for TSOs and DSOs and, ultimately, for consumers, a high degree of automatisation in the data exchange processes, sufficient digital databases of the networks and intensive cooperation between network operators is required. A basic argument for the adoption of a cost-based approach is to avoid the possibility of strategic behaviour among market players ('inc-dec gaming' ([38])). However, there is an ongoing discussion on introducing a hybrid model using the Redispatch 2.0 infrastructure, which will enlarge the pool of flexibility by allowing a voluntary market-based approach for load participation, in addition to the current mandatory cost-based approach for generation. Moreover, on the demand side, there

([38]) Inc-dec gaming refers to the possibility of some market players artificially creating a congestion problem in order to trigger the activation of flexibility.

are several ongoing pilot projects aiming at coordinating charging plans between battery EVs and DSOs using the Redispatch 2.0 infrastructure to avoid local congestions (AFRY, 2021).

3.2.3. Market-based procurement of distributed flexibility

The rest of the countries reviewed in this report adopt a market-based approach, either through a business-as-usual approach or at a trial stage. In France, the main value of flexibility lies in the integration of growing penetration levels of renewable energy in the most cost-efficient way. The largest DSO in France (ENEDIS) published its vision of embedding local flexibility to accelerate the energy transition and enhance the performance of the distribution network in 2019 (ENEDIS, 2019), followed by a roadmap for integration of flexibility in the network operation and planning, which was published in February 2020 (ENEDIS, 2020a). As part of this roadmap, ENEDIS identifies two main opportunities (use cases) in which the integration of local flexibility could prove beneficial.

1. Facilitate the connection of customers and accelerate and increase the integration of renewable energy into the grid by (1) offering smart (conditional) connection arrangements to both MV consumers and producers and (2) promoting the development of renewable energy by optimising grid planning under the regional renewable energies connection master plans (S3REnR). In the context of the latter point, the ReFlex project ([39]) aims to increase the hosting capacity of a set of selected HV / MV primary substations by 2.5 GW owing to market-based flexibility procurement as an alternative to generation curtailment. The project is part of a regulatory sandbox with a target year for feedback provision of 2022, which will be followed by potential changes to the regulatory framework. In the context of the ReFlex project, ENEDIS procures downwards flexibility (generation reduction) in two geographical areas and the first call for tenders was launched in 2021.
2. Optimise planning and operation of the distribution grid by deploying flexibility to (1) repower customers before or after an incident, (2) enhance work planning (by preventing outages linked to planned works on the distribution grid) and (3) defer grid investments. ENEDIS publishes flexibility opportunities (location, time, type of flexibility product, minimum bid, etc.) based on the identified network constraints that the distribution grid faces (see also Section 4.8).

In the Netherlands, flexibility for congestion management in the distribution grids is procured using the TSO/DSO coordination platform GOPACS, which has been in operation since 2019. An extensive overview of GOPACS is provided in Section 4.5. Furthermore, the Dutch TSO, together with the Italian and Swiss TSOs, takes part in the Equigy initiative to facilitate flexibility at LV level so that residential customers, through an aggregator, can participate in balancing services ([40]). The Netherlands is one of the European countries where flexibility markets are developed and operational – largely owing to there being a regulatory framework in place that incentivises flexibility procurement as a cost-effective solution to network capacity constraints (e.g. through yardstick competition based on TOTEX, granting DSOs the possibility of selecting the most efficient mix of expenses (CAPEX and OPEX), and TSO–DSO cooperation).

In Norway and Sweden, the adoption of a market-based approach to flexibility procurement is limited to pilot projects, the most relevant being NorFlex (Norway) and sthlmflex (Sweden), which use NODES as the market platform (see Sections 4.4 and 4.2, respectively). Such a limited approach to this type of flexibility procurement in the Nordic countries could partly be attributed to regulatory challenges, in particular the way that CAPEX and OPEX are treated, and network reinvestments that are already taking place as the networks are reaching the end of their lifetime (e.g. in Norway) (Nordic Energy Research, 2021).

However, future flexibility needs are expected to increase, with smart charging of EVs and electric heating having the largest growth potential in the near future. Another relevant factor, in this context, could be the co-existence of market-based procurement with non-market-based procurement, such as interruptible tariffs and/or conditional (flexible) connections and the way those forms of flexibility interact. The results of the survey and interviews conducted as part of the study performed by Nordic Energy Research (Nordic Energy Research, 2021) indicate that DSOs in the Nordic countries may have access to a rather inexpensive form – from their standpoint – of flexibility procurement today, in the form of interruptible tariffs, particularly if these tariff reductions can be recovered from other customers, who may not necessarily send the right cost signal to the DSO. In addition, according to the same study, the preference of some DSOs in the Nordic countries for non-market-based solutions may reflect their concern for long-term reliability and predictability, particularly in view of the current setup of local flexibility markets in the Nordic countries, as they are in the early stages of

([39]) https://flexibilites-enedis.fr/
([40]) https://equigy.com/the-platform

commercial development. On the other hand, the results of the interviews conducted as part of this study showed a clear preference for market-based approaches in the future in Norway, whereas interruptible tariffs were reported to be seen as a security back-up (Pedersen, 2021a).

In the United Kingdom, flexibility is considered one of the key enabling factors for accelerating a clean, but also more cost-effective and reliable, energy transition, while ensuring that regulation is fit for purpose. In this context, the regulator (Ofgem) with the government published a second joint plan for smart systems and flexibility in July 2021, which sets out a vision, an analysis and a set of clear policy actions to drive a net-zero energy system (Department for Business, Energy & Industrial Strategy and Ofgem, 2021). From 2030, the United Kingdom is expected to have unlocked 'full chain' flexibility – with all flexible supply and demand energy resources contributing to their full potential – to be able to respond efficiently to available energy and network resources. This plan also includes a monitoring framework for flexibility to understand how flexibility markets perform and the barriers to participation in flexible technologies, among other things, so that government and the regulator can identify actions to determine the right trajectory.

In a questionnaire sent to regulators (Anaya and Pollitt, 2021), energy associations and DSOs in the few countries with a supportive regulatory framework for flexibility procurement, many of the respondents from the United Kingdom agreed that the TOTEX regulatory model implemented since 2015 (as part of RIIO-ED1) has had a positive impact in terms of unlocking the value of flexibility. Some critical changes are to be included in the next regulatory period (RIIO-ED2), starting in April 2023. One of the key lessons learnt from RIIO-ED2 is that the overall high cost for consumers is largely attributed to the underspend allowances and rewards from quality incentives, particularly the interruptions incentive scheme (Ofgem, 2020a). Moreover, some of the respondents pointed out that procuring flexibility can save TOTEX, but this also means lower RAB; therefore, more incentives to manage uncertainty (e.g. load growth) through flexibility are needed, which should also be part of TOTEX. In addition, flexibility should be considered and valued in terms of outputs and the benefits that it can bring to the whole system. To capture efficiency across the whole system, the next price control period will have a greater focus on a whole-system approach (Ofgem, 2020b), including a coordinated adjustment mechanism re-opener, which will allow realignment of revenues and responsibilities of projects within and across sectors to deliver net benefits to electricity consumers.

Table 3 provides an overview of the different solutions to flexibility procurement in the countries selected for our analysis.

Table 3: Solutions to flexibility procurement

	France	**Germany**	**Nether-lands**	**Norway**	**Sweden**	**United Kingdom**
Network tariffs	ToU and critical peak pricing	Reduced network charges for the provision of a load control (LV consumers)	Uniform capacity-based tariffs for residential consumers	— Capacity-based residential network tariffs — Interruptible tariffs	— Capacity-based residential network tariffs (a few DSOs) — Interruptible tariffs	Distribution use of system charges under RIIO-ED2 (e.g. more granular zones for charging and time bands for ToU charges)

Connection agreements	Flexible connections for MV network users (producers and consumers)	Flexible connections	—	—	—	Flexible (non-firm) connections (enhanced access rights under RIIO-ED2)
Market-based procurement of flexibility	Yes	No (*)	Yes	Yes (trial phase)	Yes (trial phase)	Yes

(*) Hybrid model under discussion (cost-based for generation + voluntary market-based for load).

Source: JRC analysis.

3.3. Participation of independent aggregators

Article 17 of the electricity market directive lays out requirements about the integration of market participants engaged in aggregation and independent aggregation into the electricity market. More specifically, paragraph 1 of Article 17 calls for Member States to 'allow final customers, including those offering demand response through aggregation, to participate alongside producers in a non-discriminatory manner in all electricity markets'. Furthermore, paragraph 2 of the same article states that:

> *Member States shall ensure that transmission system operators and distribution system operators, when procuring ancillary services, treat market participants engaged in the aggregation of demand response in a non-discriminatory manner alongside producers on the basis of their technical capabilities.*

Moreover, Article 2(19) of the electricity market directive defines an 'independent aggregator' as a market participant engaged in aggregation who is not affiliated to the customer's supplier.

In addition, the electricity balancing guideline ([41]) led to the initiation of discussions in some countries, such as the Netherlands and the United Kingdom, on independent aggregators through the implementation of a balance service provider (BSP) independent of a BRP, which to some extent mirrors the separation between the role of the supplier and the role of aggregators.

In the following subsections, we first provide a brief overview of existing regulatory frameworks for demand-side participation in the European countries selected for our analysis, to understand how such frameworks support the development of independent aggregators and the market access of these actors in all electricity markets. We then provide an overview of the aggregation frameworks adopted in the selected countries, and particularly with respect to the type of contractual models between aggregators and BRPs/suppliers, the balancing and financial responsibilities of the former, and the compensation mechanisms in markets in which independent aggregators participate.

3.3.1. Regulatory framework for demand-side participation

Technological progress in the management of both grid operation and the integration of renewable generation has unlocked different opportunities for consumers. The clean energy package adopted in 2019 clearly acknowledges the critical role of consumers in providing the required flexibility for the future energy system by referring to a 'consumer centric electricity market design'. Some of the provisions of the electricity market directive for the development of demand-side flexibility include non-discriminatory access to all electricity markets and the recognition of (independent) aggregators as market participants.

In this context, Article 32 of the electricity market directive encourages Member States to develop the necessary regulatory frameworks to allow system operators to procure and deploy flexibility in their networks to effectively respond to network congestions. Furthermore, Article 17 of the same directive addresses the need of such regulatory frameworks to facilitate participation of (independent) aggregators in the market.

([41]) See Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing.

A recent monitoring report from smartEn reveals that, despite some progress made in some Member States, substantial effort is still needed to unlock the full potential of demand-side flexibility and to develop and implement the right regulatory framework (smartEn, 2022).

In France, the regulatory framework for demand-side participation has been in place since 2014 and, since then, it has been under constant development, which makes it one of the most advanced in Europe. Demand-side flexibility can participate in the day-ahead and intraday market, balancing market and capacity market, as well as in TSO and DSO congestion management services.

In Germany, access to demand-side flexibility is limited to participation in the balancing and the wholesale markets – in the latter only within the BRP's portfolio.

In the United Kingdom, demand-side flexibility can participate in balancing, capacity and wholesale (only within the BRP's portfolio) markets and in the provision of TSO and DSO constraint management services.

In the Netherlands, demand-side flexibility can participate in the balancing market (the frequency containment reserve (FCR), automatic frequency restoration reserve (aFRR) and manual frequency restoration reserve direct activated (mFRRda)) implicitly in passive balancing within the BRP portfolio and in the provision of TSO and DSO congestion management services (through GOPACS). The recent energy law proposal ([42]) includes provisions for DSOs to perform market-based congestion management and it also specifies the role of aggregator and independent aggregator. In addition, a very recent decision of the regulator ([43]) encourages network operators to utilise their grids more efficiently by procuring flexibility when dealing with congestion management. The decision revises and updates the rules on transmission scarcity and congestion management with the aim of making them more applicable to congestion management in the distribution networks.

In Norway, demand-side flexibility has access to the balancing, capacity and wholesale markets and to TSO congestion management services. Similarly, in Sweden, demand-side flexibility can participate in balancing, TSO congestion management and the wholesale market. The participation of demand-side flexibility in the provision of DSO congestion services is still in the trial phase in both Norway and Sweden.

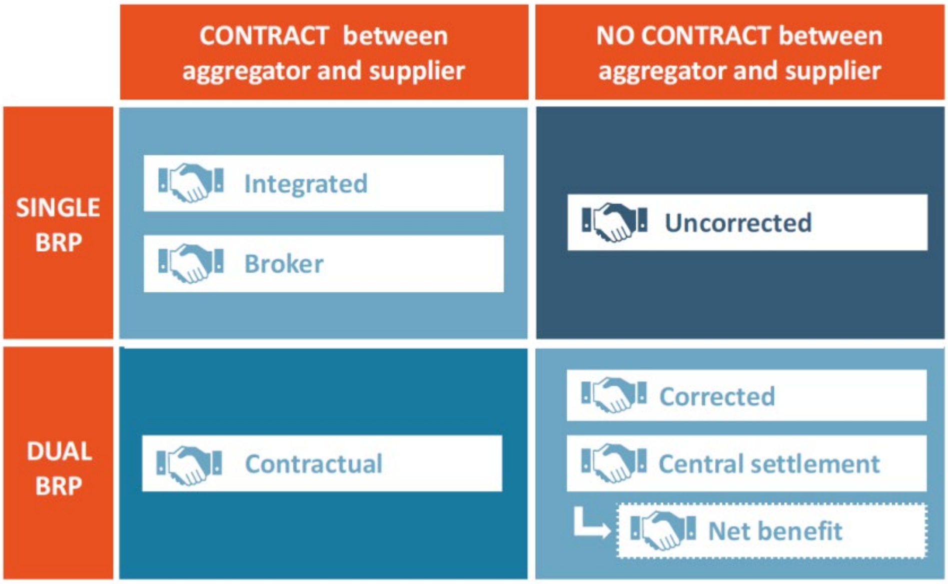
3.3.2. Aggregator models adopted in the selected European countries

The electricity market directive recognises independent aggregators as market actors, and therefore ensures that customers are free to purchase electricity services independently of their supplier. Article 13 of this directive eliminates the requirement of prior consent by suppliers, for final customers (through independent aggregators) to be able to provide services at different markets. This means that independent aggregators are market parties not affiliated with the customer's supplier and therefore are free to access different markets without needing the prior consent of the customer's supplier.

In this context, the universal smart energy framework (USEF) defines aggregator implementation models as market models for the aggregator role, describing the aggregator's contractual relationship to the supplier and its BRP. Furthermore, each model describes how balance responsibility, sourcing position and associated transfer of energy (ToE) between the aggregator and the supplier, as well as information exchange, are organised (Figure 2). The following subsections provide a closer look at the different aggregator implementation models.

([42]) https://www.internetconsultatie.nl/energiewet
([43]) https://www.acm.nl/nl/publicaties/codebesluit-congestiemanagement

Figure 2: USEF aggregator implementation models



Source: Armenteros et al. (2021).

3.3.2.1. Independent aggregator implementation models

In a nutshell, the three most widespread types of independent aggregator models in Europe are uncorrected, corrected and central settlement models (de Heer, van der Laan and Armenteros, 2021). None of these models requires a contractual relationship between the aggregator and the supplier, and a brief overview of each of these models follows (see

Table 5 for a summary of the models across the different markets and products).

Uncorrected model

In this model, the aggregator does not hold balancing or financial responsibility for the imbalances caused in the system following the activation of flexibility. There is also no energy transfer between the aggregator and the supplier. Therefore, the aggregator can create an imbalance in the portfolio of the supplier's BRP. Nevertheless, if the flexibility contributes to the system balance, the supplier's BRP is remunerated through the imbalance settlement mechanism for passive contribution to balance restoration. This model is deemed suitable for products with few and short activations and thus low amounts of activated energy (e.g. frequency containment reserve for disturbances (FCR-D) in the Nordic countries) (ENERGINET, FINGRID et al.).

Central settlement model

In this model, the aggregator holds balancing (and financial) responsibility for the imbalances caused because of flexibility activation. A central entity (a TSO or an imbalance settlement responsible party) corrects the balancing perimeter of the supplier's BRP and settles the compensation for the ToE based on a predefined formula set by the regulator. In such cases, the aggregator pays for the sourced energy, at the ToE price, to the central entity and then the central entity transfers the payment to the supplier. In the case of generation reduction or load increase, both the energy and the payment will follow the opposite direction. An alternative to this model is the net benefit model, in which the sourced energy is compensated by the consumers (through tariffs), who benefit from the flexibility activation, as opposed to the aggregator.

Corrected model

Similarly to the central settlement model, in this model the aggregator is balance (and financially) responsible for the imbalances caused as a result of flexibility activation. This model requires modification of the customer's meter readings, based on the amount of flexibility activated by the aggregator. The aggregator must assign a BRP that holds responsibility for the difference between the actual consumption and the baseline (corrected measurements). The supplier bills the same energy volume to the customer as if no activation has taken place. As the energy is transferred through the customer, the aggregator pays the customer for the energy that has been billed, but not consumed (or vice versa in the case of load increase), depending on the contract conditions between the customer and the aggregator (the flexibility service contract). In addition, variations of this model may impose responsibility on the aggregator for possible rebound effects because of the flexibility activation, typically outside the activation window, resulting in two different versions of this model (Nordic Energy Research, 2022).

Split-responsibility model

Another alternative to the USEF aggregation models is the split-responsibility model (also called the split-supply model – see de Heer, van der Laan and Armenteros (2021)). This model is already being piloted in the Nordic countries (ENERGINET et al..; Färegård and Miletic, 2021) and it separates the energy supply and balance responsibility by dividing the part of the energy and associated asset(s) controlled by the aggregator, and the remaining load (non-controlled assets). In this case, the aggregator operates the controllable part of the connection and is responsible for contracting supply for that part, whereas the retailer supplies the remaining load (non-controllable). The aggregator can fulfil its sourcing and balance responsibilities either by entering into a contract with a single supplier (and a BRP) for all its customers or by performing this role itself. This model typically requires installation of submetering for the controllable part of the load. This model focuses on the split of the energy supply and, as such, it can be seen as complementary to the USEF aggregator implementation models, thus allowing for any combination of the two concepts (Armenteros, de Heer and van der Laan, 2021).

3.3.2.2. Non-independent aggregator implementation models

Alternatives to the independent aggregation models are three types of non-independent aggregation models that are present in the European energy landscape: contractual, integrated and broker models.

In the integrated model, the supplier and the aggregator roles are combined within a single market party.

In the broker model, the aggregator transfers the balance responsibility to the BRP of the supplier, and compensation for the imbalances caused and the pre-bought energy by the supplier is settled bilaterally between the aggregator and the supplier based on contractual arrangements. The aggregator also has a flexibility service contract with a BSP offering its flexibility to the TSO.

In the contractual model, the aggregator is balance responsible for the imbalances caused by the activation of flexibility and only during the periods of activation and, thus, it assigns its own BRP to cover the imbalance. In addition, the aggregator compensates the supplier for the ToE based on a contract that includes a formula for the calculation of the ToE agreed between the two parties and preferably using a standardised method. Furthermore, the BRPs of the supplier and of the aggregator enter into a contract on the correction of the balance perimeter. Finally, the aggregator or its BRP has a flexibility service contract with a BSP, which offers flexibility to the TSO.

3.3.2.3. Implementation of aggregator models in the European countries examined

Table 4 provides an overview of the types of aggregation models implemented in the countries selected for our analysis; they mainly concern flexibility traded on the balancing, wholesale and capacity markets.

In France, the uncorrected model is applied for the FCR and aFRR products; however, for the provision of the aFRR, demand-side flexibility can participate only through a secondary market. As for the other products – mFRR, replacement reserve (RR), the capacity market, and day-ahead and intraday trading – the corrected and the central settlement models are applicable, and the choice is based on the connection characteristics. As for the balancing responsibility, an aggregator active in the wholesale and capacity markets is accountable for the imbalances caused by the flexibility activation. In the case of the balancing market, the aggregator acts as a 'floating BSP' and thus is only financially responsible for deviations from the procured amount of flexibility (Nordic Energy Research, 2022). Another relevant aspect to mention in the context of flexibility procured in these markets is that the French regulation only considers load reduction and generation increase as demand response, while load increase or generation reduction is not (yet) considered.

The German regulation considers two aggregation models – uncorrected and corrected. The former applies to the FCR product and the latter, implemented in 2021, concerns the mFRR and aFRR products (Nordic Energy Research, 2022). Under this model, the aggregator must hold a BRP certificate and, following flexibility activation, it exchanges schedules with the supplier's BRP for the correction of the balance perimeter. Next, following the correction of the imbalance, the supplier corrects the energy bill of the customer as if no flexibility activation has taken place.

In the United Kingdom, there are two models applicable, depending on the type of product – the uncorrected model and another, that is, either the central settlement model or the corrected model, depending on the circumstances (Nordic Energy Research, 2022). The uncorrected model is applied for balancing products, such as FCR and the capacity market. As for aFRR, mFRR and RR, the central settlement model applies. To be able to participate in these markets, the aggregator needs to register as a virtual lead party (VLP), which is basically equivalent to a BSP role. The compensation for the ToE depends on customers' consent to share their flexibility activation data with the retailer. If the customer allows these data to be shared, the imbalance settlement responsible party then shares the activation volumes with the supplier; therefore, the supplier could charge the customer for the ToE as a separate specification, which basically mirrors the corrected model. On the other hand, if the customer does not allow data to be shared, the compensation would be zero and the model in this case could be mapped as a central settlement model with no compensation (ToE = 0).

Table 4: The aggregation models followed in the European countries analysed

Member State	**FCR**	**aFRR**	**mFRR (and RR)**	**Wholesale market**	**Capacity market**
France	Uncorrected	Uncorrected	— Corrected — Central settlement	— Corrected — Central settlement	— Corrected — Central settlement
Germany	Uncorrected	Corrected	Corrected	Integrated	N/A
Netherlands	Uncorrected	Integrated/ broker/ contractual (plan for central settlement)	Integrated/ broker (plan for central settlement)	Integrated/ contractual	N/A
Norway	Integrated/ broker/ contractual	Integrated/ broker/ contractual	Integrated/ broker/ contractual	Integrated/ broker/ contractual	N/A
Sweden	Integrated/ broker/ contractual	Integrated/ broker/ contractual	Integrated/ broker/ contractual	Integrated/ broker/ contractual	N/A
United Kingdom	Uncorrected/ central settlement	Central settlement	Central settlement	Independent aggregators not allowed (plan for central settlement)	Uncorrected

Source: JRC analysis adapted from Nordic Energy Research (2022)

In the Netherlands, the uncorrected model is applicable to the FCR product, while the new energy law (44) proposes that the central settlement model (45) be applied in the future to the aFRR and mFRR products for, among other things, facilitating independent aggregation (Nordic Energy Research, 2022). Currently, for aFRR and mFRR, the Dutch TSO corrects the BRP perimeter after flexibility activations based on data shared by the aggregator following an activation of flexibility. In addition, the aggregator needs to coordinate or make an agreement with the customer's supplier – a situation that is likely to change once the central settlement model is fully adopted. As for the local flexibility services traded through GOPACS, the contractual model applies (Armenteros, de Heer and van der Laan, 2021).

In Sweden, there are currently very few aggregators, none of which can be considered independent. One reason for this is the current structure of balance responsibility (Färegård and Miletic, 2021). The aggregator needs to sign a contract with the customer's supplier and its BRP, in which the aggregator needs to negotiate with the

(44) https://www.rijksoverheid.nl/documenten/publicaties/2021/11/26/wetsvoorstel-energiewet-uht
(45) The exact model is to be specified by lower legislation, however, the national regulatory authority has indicated the central settlement model as the most likely option to be adopted

supplier and/or BRP the conditions for the financial settlements linked to the imbalance caused and the compensation to the supplier for the pre-bought energy. In addition, the supplier and its BRP can, in many cases, act as competitor to the aggregator, unless they are the same actor, as in the integrated model (Färegård and Miletic, 2021). To address this, the regulator proposed a regulatory framework for independent aggregators in 2021, with a proposition for legislative changes to the Swedish electricity act, planned to be enforced in 2022 ([46]). The proposed framework recommends the implementation of two different models for independent aggregators – the split-responsibility model and either the central settlement model or the corrected model – all complying with the requirements of the EU market electricity directive for independent aggregation. The aggregator will be allowed to choose between these models or the integrated model currently in place.

In Norway, there are no independent aggregators commercially participating in any electricity market. The integrated aggregation model is present, although is still facing some challenges; for example, entry barriers to balancing markets is mostly limited to BRPs, meaning that BSPs cannot enter the market directly without becoming BRPs themselves. In addition, aggregation is allowed only within one bid zone, and load and generation cannot be aggregated in the same bid unless they belong to the same BRP (ENERGINET et al.). Another model partially implemented is the split-responsibility model (also called the dual-supply model). Under this model, the aggregator is required to have a contract with the retailer for the electricity supply, and it requires new metering equipment (a sub-meter) for the flexibility asset (e.g. EV) as a basis for validation of the delivered flexibility. Therefore, this model adds additional complexity, such as the need for dual billing for the customer (ENERGINET et al.). Some ongoing pilot projects, such as NorFlex, are expected to provide useful insights into the direction of flexibility provision by independent aggregators.

3.3.3. Balance responsibility

Article 15(2)(f) of the EU electricity market directive states that:

> *Member States shall ensure that active customers are financially responsible for the imbalances they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with Article 5 of Regulation (EU) 2019/943.*

Similarly, Article 17(3)(d) indicates that:

> *Member States shall ensure that their relevant regulatory framework contains at least the following elements: an obligation on market participants engaged in aggregation to be financially responsible for the imbalances that they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with Article 5 of Regulation (EU) 2019/943.*

In this context, this section provides an overview of the balancing and financial responsibility of the network users providing flexibility services directly or through an intermediary (aggregator) and the contractual relationship between the aggregator and the supplier / the supplier's BRP.

In France – as the only country among those analysed that has opened access for independent aggregators to all markets – independent aggregators do not need to assign or perform the BRP role in the balancing market, as they act as 'floating' BSPs. However, they are exposed to imbalance penalties for any deviation from the procured amount of flexibility. Nevertheless, independent aggregators participating in the wholesale and capacity markets are required to assign or perform the role of a BRP.

In Germany, independent aggregators are allowed to participate only in the balancing market, and they do not need to assign a BRP. Nevertheless, they need to hold a BRP certificate, issued by the customer's BRP. Following flexibility activation, they exchange energy schedules with the supplier's BRP for the correction of the imbalance perimeter (see Section 3.3.2.1 for an explanation of the corrected model).

Like in Germany, in the Netherlands, independent aggregators are allowed to participate only in the balancing market, without performing the BRP role. However, they are exposed to imbalance penalties for any deviation from the procured amount of flexibility.

In the United Kingdom, independent aggregators can participate in the balancing mechanism and for the provision of RR, and they do not hold balancing responsibility. However, they need to register as VLPs (equivalent to a BSP role) and they are exposed to penalties (at least the imbalance price) for under-delivery.

([46]) https://ei.se/om-oss/publikationer/publikationer/rapporter-och-pm/2021/oberoende-aggregatorer--forslag-till-nya-regler-for-att-genomfora-elmarknadsdirektivet--ei-r202103

It is important to mention here that, in the models in which aggregators need to assign a BRP or perform the role of the BRP, the aggregator is balance responsible only for the period when flexibility activation occurs.

In Norway and Sweden, there are no commercially active independent aggregators and, therefore, experience with market access of independent aggregators to mainly balancing and local flexibility markets is limited to pilot projects. Currently, aggregators in these countries cannot participate in the balancing markets directly if they are not also a BRP.

Table 4 summarises the implementation of balance and financial responsibility for independent aggregators.

3.3.4. Compensation mechanisms

Article 17 of the EU electricity market directive indicates that:

> *Member States may require electricity undertakings or participating final customers to pay financial compensation to other market participants or to the market participants' balance responsible parties, if those market participants or balance responsible parties are directly affected by demand response activation. Such financial compensation shall not create a barrier to market entry for market participants engaged in aggregation or a barrier to flexibility. In such cases, the financial compensation shall be strictly limited to covering the resulting costs incurred by the suppliers of participating customers or the suppliers' balance responsible parties during the activation of demand response. The method for calculating compensation may take account of the benefits brought about by the independent aggregators to other market participants and, where it does so, the aggregators or participating customers may be required to contribute to such compensation but only where and to the extent that the benefits to all suppliers, customers and their balance responsible parties do not exceed the direct costs incurred. The calculation method shall be subject to approval by the regulatory authority or by another competent national authority*.

This section provides an overview of the compensation mechanisms applied in the EU countries analysed.

In Germany, the aggregator compensates the supplier through the customer at retail price level for the sourced energy. In addition to the retail price, the aggregator may compensate the supplier's BRP to cover the administration costs for schedule exchanges and it is up to the BRP (in negotiations with the aggregator) to set the price.

In the United Kingdom, if the customer agrees to share their data, the supplier can charge the consumer for the energy offered as flexibility and the aggregator would, in turn, compensate the consumer. If the customer does not consent to share their data, there is currently no compensation between the aggregator and the supplier, which corresponds to a ToE price equal to zero. This is, however, likely to change in the future, particularly in view of the discussion on opening the wholesale market to VLPs (Nordic Energy Research, 2022).

In France, the formula for calculating the ToE price reflects the average sourcing cost for electricity and differentiates between two types of sites: profiled and half-hourly settled sites (for industrial and commercial consumers). In this context, the French TSO publishes the prices for the coming year in the preceding December and the prices are fixed with a ToU component (peak/off-peak) and by season (winter/summer).

In the Netherlands, the compensation is agreed between the BRP of the supplier and the aggregator. Once the central settlement model is fully in place, the price of the ToE or the formula for its calculation will be prescribed by the regulator.

The Nordic Energy Regulators point to a trade-off between the degree of compensation to BRPs from independent aggregators and the attractiveness of the independent aggregator business case. In this sense, strict requirements for compensation are likely to form an entry barrier for independent aggregators (ENERGINET et al.).

Table 5 provides an overview of the access of independent aggregators to different markets and their balance and financial responsibility in the selected EU countries. It also summarises the compensation level (formula) between the aggregator and the supplier for each country analysed.

Most of the traded flexibility in the markets mentioned above is offered by industrial and commercial customers. Part of the reason for this lies in the lack of smart metering infrastructure (e.g. in Germany). In the Netherlands, residential customers can only offer their flexibility within the supplier's portfolio. Norway and Sweden are still in the early stages of developing commercial flexibility markets at DSO level and there is a lack of a regulatory framework for independent aggregators. France is the only country among the analysed countries that allows the participation of residential customers in flexibility markets, normally applying the central settlement model.

Table 5: Flexibility markets design

Market characteristic	France	Germany	Netherlands	Norway	Sweden	United Kingdom
Market access of independent aggregators	FCR, mFRR, RR, aFRR, wholesale market, capacity market, congestion management	FCR, aFRR, mFRR	FCR, aFRR, mFRR	Limited to trials (mFRR, intraday, local flexibility markets)	Limited to trials	FCR, Fast Frequency Reserve (FFR), aFRR, Fast Reserve (FR), mFRR, Short term Operating Reserve (STOR), wholesale market, capacity market, congestion management
Balancing and financial responsibility	— No need to be/assign a BRP (balancing market) — Need to be/assign a BRP (wholesale and capacity markets) — Financial responsibility (*)	— No need to be/assign a BRP (balancing market) — Financial responsibility (*)	— No need to be/assign a BRP (balancing market) — Financial responsibility (*)	Need to be/assign a BRP	Need to be/assign a BRP	— No need to be/assign a BRP (balancing market) — Financial responsibility: yes (**)
Type of customers	Industrial/commercial and residential	Industrial/commercial	Industrial/commercial	Mainly industrial/commercial	Industrial/commercial	Industrial/commercial
Compensation level	— Corrected model: retail price or approximation of the sourcing costs — Central settlement model: formula is set by the regulator	Retail price (+ additional administrative costs)	Not yet (to be adopted in the future for the central settlement model)	–	–	Equal to zero if the customers do not share their data, otherwise paid to the supplier (not regulated price)

(*) At least for under-delivery.
(**) Only for under-delivery.
Source: JRC analysis adapted from Nordic Energy Research (2022).

4. Presentation of flexibility markets in Europe

4.1. NODES market platform

4.1.1. General information

- Date of foundation: early 2018
- Date of release of commercial market platform: early 2019
- Website: https://nodesmarket.com/

NODES is a flexibility market platform deployed in various pilot projects, with the most notable being:

- sthlmflex in Sweden, deployed by two Swedish DSOs (Ellevio and Vattenfall Eldistribution) and the national TSO (Svenska Kraftnät);
- IntraFlex in the United Kingdom, deployed by the UK DSO Western Power Distribution;
- NorFlex in Norway, deployed by two Norwegian DSOs (Agder Energi and Glitre Energi) and the national TSO (Statnett).

NODES was established by a Norwegian utility, Agder Energi (acting among other things as a DSO), and the European power exchange Nord Pool. Since 15 December 2021, it has been owned 100 % by the former (NODES n.d.). It was developed with the purpose of creating flexibility markets in which flexible assets at all levels of the grid can sell flexibility to both DSOs and TSOs.

The following subsections present the general market architecture proposed by NODES (note that the specifics in each deployed market can differ significantly, as shown in the following).

4.1.2. Pre-qualification procedures

Flexibility assets are registered in the NODES platform by FSPs. At the very least, the metering point identification must be included. Before assets can be offered in the market, the local DSO must approve and confirm that the asset exists in its grid and that they are in the right location.

As a general principle, the regulatory compliance and financial capacity of the FSPs is pre-qualified, as are the technical characteristics of their flexibility assets. The former can be undertaken by the market operator (NODES), while the latter falls under the local DSO's responsibility. So far, regulatory, commercial and financial capacity checks have been rather light owing to the pilot nature of the projects in which the NODES market platform has been deployed (Stølsbotn and Eng, 2021). The financial risk from the seller side (FSPs) is considered to be rather low, given that there are no penalties for partial delivery of flexibility (see also Section 4.1.5), while, from the buyer side, network operators are considered financially trustworthy by default. FSPs that are not BRPs (i.e. independent aggregators) are accepted in the marketplace.

The FSPs must undertake a system test in which they verify the trading and activation of their assets in a test with the DSO. Once this test is completed, the FSP's systems are approved, and additional flexibility assets can be registered without undertaking another system test (Stølsbotn, 2021). Depending on the exact application, DSOs may opt to exclude certain flexibility assets depending on their location. The pre-qualification process by NODES takes 1 day, on average, subject to the level of automation of FSPs and DSOs (Stølsbotn, 2021).

As a general rule, the NODES market platform does not envisage minimum or maximum nominal capacity limits for the flexibility assets.

4.1.3. Flexibility products

The NODES market platform accommodates trading of products aimed at network deferral, congestion management and the enhancement of network resilience. The common feature is that, in all cases, the flexibility assets have to offer real power injections/withdrawals. Trading of flexibility services aiming at reactive power/voltage control is also soon to be tested in a pilot (Eng, 2022).

NODES envisages both a long-term market (LongFlex) and a short-term market (ShortFlex). Products in these could have both an availability and an activation component. Minimum offer limits could be down to 1 kW, and bids are divisible.

Based on the survey results, the NODES market platform foresees that steady-state voltage control, inertia for local grid stability and island operation capability could be required as specific flexibility services by network operators in the next 5 years. For all of them, market-based procurement could be the preferred option.

4.1.4. Market architecture

In its full conceptual implementation, NODES aims to offer a market platform for an integrated flexibility marketplace in which FSPs trade with BRPs, DSOs and TSOs (NODES). As such, the services offered will include portfolio optimisation (for BRPs), congestion management (both long term and short term, primarily for DSOs) and frequency regulation services for the TSO. In principle, all of these actors would compete against each other for flexibility services, even though in most actual pilot implementations the DSO has precedence over the TSO in the procurement of flexibility (i.e. only the unused offers are passed to the TSO, often in aggregated form). So far, in the projects in which the NODES market platform has been deployed, only network operators are buyers of flexibility services (i.e. the BRPs' participation as buyers of flexibility is not permitted).

In the LongFlex market, availability products (possibly with activation components too) are traded. In real projects when the NODES market platform is deployed, products with weekly and seasonal (2–4 months) availability have been deployed.

The ShortFlex market is a continuous, pay-as-bid market. The buyer network operator announces its flexibility needs in advance and calls FSPs to submit offers, but the latter can also submit offers proactively. Trading of activation products usually opens 7–10 days and closes 1–2 hours before physical delivery. Technically, the MTU can be as low as 1 minute, but a common practice is to align the MTU with the imbalance settlement period.

Regarding the spatial setup of the flexibility market, this is based on congestion zones, inside which an FSP can aggregate its resources. The definition of congestion zones, and thus the level of acceptable aggregation, is left to be defined by network operators for each specific test case. The idea of differently defined congestion zones between the DSO and the TSO is supported. Under this concept, each TSO can aggregate offers from several DSO congestion zones.

Offers in the flexibility markets where the NODES platform has been deployed are cleared based on their price (per congestion zone). Conceptually, there are no price caps, and pay-as-bid is the pricing mechanism for activation products. Technically, availability products can be priced based on either a pay-as-bid or a pay-as-clear mechanism. In actual projects, the buying network operators either have opted for the former option or predetermined the remuneration price.

Nominally, domestic end-customers could participate directly in the NODES flexibility markets. However, this is very rare in practice, mainly owing to the lack of financial incentives and necessary technical acumen (Stølsbotn and Eng, 2021). Therefore, the participation of assets belonging to residential consumers is made through aggregators (e.g. as part of the electricity supply offer).

While, in principle, DSOs and TSOs can compete for flexibility based on price, network operators' operational security coordination has not yet been addressed in detail by the NODES market architecture. NODES envisages that the lower level network operator (e.g. a local DSO) could restrict the higher level network operator (e.g. a regional DSO) to activate flexibility in its grid if this could cause problems. However, the functionality of security coordination is not developed yet as a standard feature (Stølsbotn, 2021).

4.1.5. Activation and settlement procedures

Activation of flexibility is made by FSPs upon successful clearance of their offers. Communication is made by email, SMS and/or an application programming interface (API). In principle, there is nothing stopping the NODES market platform from letting DSOs undertake the activation of flexibility remotely by direct access to the flexibility assets, but this has not been requested thus far.

Usually, settlement and measurement periods ([47]) are the same. The NODES market platform has been deployed in projects in which the settlement was in a 1-minute and 1-hour basis.

The NODES market platform permits both options regarding baselining: FSPs declaring their schedules and baseline calculation based on a predefined method. For the latter, the default baseline is a simple average

([47]) The measurement period is the time period during which the energy consumption or production is measured based on the technical capabilities of the associated meter. The settlement period is the period during which the financial settlement of the activated flexibility is made.

looking back 5–10 days, although the NODES team is exploring other options (Stølsbotn and Eng, 2021). Based on the responses to the survey, FSP schedule declaration may provide a more sophisticated solution; it has been the preferred option by the respondents, as it allows FSPs to better manage their assets and achieve value-stacking. On the other hand, it is acknowledged that settlement based on FSP schedules opens opportunities for potential gaming. This is why, in certain projects (e.g. in the sthlmflex flexibility market), market surveillance processes have been introduced by the buying network operators when FSPs opt for declaring schedules, such as an explanation of their baseline methodology, record keeping of consumption data, and a comparison between the latter and baseline declarations. Finally, it is noted that, owing to the inherent problems of flexibility products associated with a baseline – given that the latter can only be a forecast, irrespective of the entity performing it – the NODES market platform also investigates products that would not need the employment of a baseline, such as consumption caps ([48]), even though these have not been employed so far in a real project (Stølsbotn and Eng, 2021).

The settlement of availability products is made only after the activation period. The remuneration level depends on the level of submission of offers for activation (Eng, 2022).

In the pilot projects in which the NODES market platform has been deployed, no penalties are applied in the case of partial delivery of flexibility, but there is a reduction in compensation. Nevertheless, the survey results show that penalties may become relevant when flexibility markets reach full commercialisation stage.

The financial cost of imbalances caused by the activation of flexibility is borne by BRPs. However, NODES has developed, in the context of the IntraFlex project, an information page service through which BRPs can see the trades of FSPs with flexibility assets under the balance responsibility of BRPs (see also Section 4.3).

4.1.6. Lessons learnt and future developments

The structured interview provided some of the insights into the experience of the NODES market platform in local flexibility market projects.

- FSPs are still experimenting with their business models. There is a difference between suppliers/BRPs who also offer aggregator services and independent aggregators. The former are usually large, established companies that see flexibility as a tool for portfolio optimisation, mainly in the wholesale market, while local flexibility markets represent only a secondary revenue opportunity. Independent aggregators are usually small technology firms exploring the option of offering additional services to their customers other than the strictly technical setup of aggregation capabilities.
- Automation of pre-qualification procedures, as well as of trading functions, are key for the development of a successful local flexibility market. In this respect, also of importance are the operational security processes of DSOs, which in many cases lack the necessary level of observability and diagnostics to maximise the value that could be offered by flexibility in the distribution system.
- The DSOs' inadequate technical sophistication, previously mentioned, and the lack of regulatory incentives for exploiting flexibility are identified as the two most significant barriers to the development of local flexibility markets, with the latter being the most serious one. Even though utilisation of local flexibility will be just part of the solution, it should be incorporated into the long-term planning of distribution networks, which most often is not the case.
- APIs seem to be, for the NODE market platform, the preferred option for automating data processes between the platform, FSPs and network operators. The interviewees seemed sceptical about the harmonisation initiatives, stating that it could imply undue burden, especially for small FSPs, such as harmonisation with the common information model (CIM) in Sweden. The need for data harmonisation (e.g. of format of baseline declarations, metering data and trading offers) is acknowledged, but it should not be dictated by network operators. Instead, FSPs must be an integral part of the harmonisation process. The interviewees also referred to the EUniversal ([49]) Horizon 2020 project aiming at fostering interoperability, of which NODES is a part.
- Regarding product design, experience of NODES shows that the existence of contracts of different temporal scales (i.e. long, medium and short term) is beneficial because of the different technical characteristics of flexibility assets.

([48]) Under a consumption cap product, the FSP offers to limit the consumption of its bidding assets under a certain limit during a specific time period.

([49]) https://euniversal.eu/

As future milestones, the interviewees identified the evolution of some pilot projects employing the NODES flexibility market platform towards a business-as-usual state in the next 2–3 years, as well as the revision of the national regulatory frameworks for DSOs towards a more TOTEX approach, which is expected to happen in different stages among the various countries.

Finally, the interviewees identified as the main benefit of independent market operators of local flexibility markets their impartiality against both sellers (FSPs) and buyers (network operators). Instead, if local flexibility markets are operated by network operators, the buying side may achieve a very dominant position, which in the end would have a negative impact on liquidity.

4.2. sthlmflex project

4.2.1. General information

- Start date: 1 December 2020
- Country: Sweden
- Status: ongoing
- Network operators involved: Svenska kraftnät (TSO), Ellevio (regional DSO), Vattenfall Eldistribution (regional DSO), E.ON Energidistribution AB (local DSO)
- Main webpage: https://www.svk.se/sthlmflex

In Sweden, the TSO offers a guaranteed amount of power withdrawal capability at each TSO/DSO interface point (called a network subscription). A mechanism of temporary subscriptions comes on top, allowing the guaranteed network subscription capacity to be temporarily exceeded upon agreement from the TSO, with a financial penalty to be paid by the DSO.

The sthlmflex flexibility marketplace is deployed in the Stockholm area to address a lack of network capacity, and it is a continuation of pilot projects on local flexibility markets developed in other parts of Sweden in the context of the CoordiNet Horizon 2020 project ([50]).

The targeted flexibility services include investment deferral, operational congestion management and enhancing network resilience. sthlmflex aims to enhance both TSO/DSO and DSO/DSO coordination. DSOs buy congestion management services from FSPs, and trade network subscription capacity rights between themselves, while the TSO buys mFRR services. Flexibility services are localised in three regional areas (Stockholm north, Stockholm south and Stockholm city). Originally, this pilot project was intended to run from 1 December 2020 to 31 March 2021, but it was decided that it would be extended through two additional winters in order to refine the details and increase incentives for even more players to participate in the market. Originally, only Svenska kraftnät (TSO), Ellevio (regional DSO) and Vattenfall Eldistribution (regional DSO) were participating in the pilot project. E.ON Energidistribution AB (local DSO) decided to be involved from the winter of 2021/2022. The two regional DSOs operate the network in the voltage ranges between 24 kV and 220 kV, while E.ON Energidistribution AB is one of the 15 local DSOs in the examined area operating below 24 kV.

Industrial and commercial customers, producers involved in the power and heat sector, and smaller assets via aggregators, including independent aggregators, currently take part in the market.

4.2.2. Pre-qualification procedures

When FSPs express their interest in participating in the sthlmflex flexibility market, they have to declare for each of the assets in their portfolio the installation identification, type of asset, nominal capacity and network jurisdiction to which it belongs (Ellevio et al., 2021a). DSOs validate the metering points supplied by the FSPs and approve the baseline methodology defined by them (see also Section 4.2.5). The pre-qualification process for FSPs mainly verifies compliance with a minimum bid step size of 0.1 MW, along with successful communication with the market platform (NODES). For seasonal contracts (see Section 4.2.3), there is also an activation test of 1-hour duration each season. For participation in the balancing market, the pre-qualification procedures defined by the TSO must be followed.

At regulatory level, FSPs have to sign a power of attorney agreement regarding metering data for all their flexibility assets and sign a contract with the market operator (NODES).

[50] https://coordinet-project.eu/pilots/sweden

On average, the pre-qualification process takes 14 days (Ersson, 2022).

For participation in the balancing energy market, FSPs must have an agreement with the respective BRPs, as, among other things, financial compensation by the TSO is provided to the latter (Ellevio et al., 2021b).

4.2.3. Flexibility products

Thus far, only upwards flexibility services are traded in the sthlmflex marketplace (i.e. an increase in local generation or a decrease in consumption).

The exact product specification changes as the project evolves. For the winter of 2021/2022, there were three types of products: seasonal (traded in the LongFlex NODES market), weekly and short-term products (both traded in the ShortFlex market).

Seasonal contracts include an availability compensation and an activation price. FSPs bid freely for both components. The clearance of offers is made solely based on the price of the availability component. For the activation component, there is a price cap (SEK 10 000/MWh (EUR 950/MWh) ([51])). Seasonal contracts aim mainly to act as lifelines to be used in a 10-year winter ([52]) or during a particular hard operation status. There are two types of seasonal contracts (Ellevio et al., 2021a):

1. cold hours in the time intervals of 11–7 and 15–21 on working days – an FSP must be able to offer flexibility for at least 2 hours during one of these two intervals or for 1 hour during both;
2. all hours in the time intervals of 11–7 and 15–21 on working days.

FSPs can bid for seasonal products for one to three seasons. It is noted that the two regional DSOs also have bilateral availability contracts out of the sthlmflex market (Ruwaida et al., 2022).

Weekly contracts were introduced in the winter of 2021/2022. They too have an availability and an activation component, but, in contrast with seasonal contracts, there is a predetermined price for the availability component and free bidding only for activation with a price cap of SEK 2 800/MWh (EUR 266/MWh). FSPs can offer flexibility for certain (or all) hours in the same time intervals as in seasonal contracts. One of the main aims behind the introduction of weekly contracts was to increase liquidity in the market (Ruwaida et al., 2022). As a result, availability compensation for weekly contracts is provided up to 40 MWh per week and in a step-wise manner: the predetermined availability price is SEK 5 000/MWh (EUR 475/MWh) for the first 10 MWh and then drops to SEK 2 000/MWh (EUR 190/MWh) for the remaining 30 MWh. In addition, it was guaranteed by the buying network operators that at least two weekly auctions would take place during the market season of 2021/2022 (Ellevio et al., 2021a).

An important point is that FSPs must be able to offer their availability when the external temperature is −5°C or lower for both seasonal and weekly products. This is because of the significance of heating loads in the overall consumption. It is noted that availability contracts are called only in Stockholm north and Stockholm city congestion areas.

Finally, 'free bids' are activation products traded in the continuous local flexibility market without a price cap.

For all products, the minimum bid size is 0.1 MW and bids are divisible (Ersson, 2022).

4.2.4. Market architecture

Trading is based on the aggregation of flexibility assets into portfolios per congestion area (Stockholm north, Stockholm south and Stockholm city). The highest voltage within each congestion area is 220 kV. The flexibility market provides the possibility for regional DSOs to use resources in the whole Stockholm region, independent of the actual location of the resource. This happens with the activation of flexibility offers and simultaneous swapping of subscription rights from one regional DSO to another. On the other hand, when both regional DSOs require flexibility, they effectively have to compete.

Seasonal contracts are procured through an auction. Offers are evaluated based on the price solely of the availability component. Auctions for weekly contracts are called on an ad hoc basis covering the next 7 days. There is an announcement from the buying network operator, and the market platform (NODES) sends an email notification. It is noted that FSPs requested an SMS to also be sent when a weekly auction is called (Ruwaida et al., 2022). For both seasonal and weekly contracts, the clearing method is pay-as-bid, with the exception of

([51]) Considering an exchange rate of SEK 1 = EUR 0.095.

([52]) The term '10-year winter' is used to describe a situation that can happen in 1 every 10 winters.

the availability component of the weekly products, which is predetermined by the buying network operators (see the previous section). For all products, the MTU is 60 minutes, as is the wholesale imbalance unit period. However, the latter in the near future will become 15 minutes.

The 'free bids' short-term market is organised on a continuous, pay-as-bid basis. It is possible for the FSPs to enter flexibility offers as early as 1 week in advance of flexibility delivery and up to 2 hours before delivery. The DSOs do most of the purchases at 9.30–10.30 on the day before the delivery; therefore, it is recommended that the FSPs place their bids on the market no later than 9.00 the day before the delivery (Ellevio et al., 2021a). The remaining flexibility offers, qualifying for mFRR services, then become available to the TSO. The timeline aims to avoid conflicts with the wholesale spot electricity market. It should be noted that there are slightly different product specifications between flexibility provision to DSOs and flexibility provision to the TSO (mFRR) (Table 6).

Offers by FSPs (for all products) can be submitted either through an API or manually in the NODES web platform.

It is noted that the financial penalty for a temporary subscription, if permitted by the TSO, presents an effective price cap in the demand for flexibility by the DSOs. According to the published results of the sthlmflex market for the winter of 2020/2021, available at the NODES website ([53]), the weighted average price of flexibility offers by FSPs was consistently above the penalty price of a temporary subscription (by a factor of 1.87 or more), making flexibility activation economically preferable only when temporary subscriptions are not available.

Table 6: Differences in product specification between the sthlmflex market and the balancing market

Specification	**Congestion management (buyer: DSOs)**	**mFRR (buyer: TSO)**
MTU	1 hour	1 hour
Notice period	> 2 hours before delivery	0 minutes
Activation time	The FSP must provide the full flexibility offer at the start of the delivery period	15 minutes to full activation
Rules for ramping	No	Only in respect of activation time
Recovery rules	No	N/A
Minimum bid size	0.1 MW (*)	1 MW (**)
Minimum bid step	0.1 MW	1 MW (**)
Maximum bid size	No	No
Maximum bidding step	No	No
Divisible bids	Yes	Yes
Activation pricing	Pay-as-bid	Pay-as-clear for balancing; pay-as-bid for congestion management in the transmission network (***)
Penalties for non-delivery	Reduced compensation for partial delivery	As per balancing market rules

(*) In contrast, the minimum participation size is 0.5 MW for availability contracts.
(**) Flexibility bids can be aggregated, but only from the same bidding zone and BRP or under contract.
(***) In the Nordic countries, the same order book is used for balancing and for congestion management in the transmission network (i.e. for the latter, TSOs activate offers submitted in the balancing energy market).
Source: JRC analysis.

4.2.5. Activation and settlement procedures

Activation of a successful flexibility offer is made by the FSP after a signal coming from the market platform (NODES) via an API, email or SMS.

FSPs can either declare a baseline position to the sthlmflex market platform or leave it to the market operator to calculate a baseline based on historical data, with the default being to take an average of hourly measurement data from 5 recent working days. For the former option to be allowed (FSP declarations), approval by the network operators is required and, if necessary, bilateral talks (Ellevio et al., 2021a). In the experience of the project partners, significant grid users (SGUs) prefer to declare schedules, while aggregators of smaller

([53]) https://nodesmarket.com/sthlmflex/

flexibility assets prefer to be settled based on a baseline defined by the market operator. So far, there have been no indications of any gaming behaviour by FSPs when they choose to declare their baseline (Ruwaida et al., 2022).

FSPs have the option to use either flexibility asset sub-meters or metering data from the connection meters of network operators. Network operators have the option to employ their own metering for flexibility assets above 1.5 MW.

- The measurement and settlement periods are both 60 minutes. If the FSP and the BRP are different entities (i.e. in the case of independent aggregators), the balance responsibility falls upon the BRP. Moreover, there are no arrangements for the independent aggregator compensating the supplier for the pre-bought energy by the latter.
- In the case of partial delivery, there are no penalties, but there is a reduction in compensation for both availability (if applicable) and activation components according to the following rules (Ellevio et al., 2021b):
    - 100 % payment for delivery at 80 % or above;
    - a linear reduction up to 40 % delivery;
    - no payment for delivery below 40 %;
    - the availability compensation is validated on a monthly basis.

4.2.6. Results, lessons learnt and future developments

The sthlmflex pilot market was put in operation for the first time during the winter of 2020/2021 (i.e. from 1 December 2020 to 31 March 2021. The flexibility market gave all regional DSOs the possibility of using resources in the whole Stockholm region, independent of the actual location of the resource. The pilot project achieved sector coupling between electricity and heat and led to a more effective use of the electricity network (Ellevio et al., 2021c).

The winter of 2020/2021, according to the Swedish Meteorological and Hydrological Institute, was milder than usual, with only a few cold weeks in February (not a 10-year winter). At the same time, the Stockholm region had good access to local electricity production, and the transmission grid presented normal operating conditions. It should be noted that the potential impact of COVID-19 on capacity needs has not been analysed.

The process for participants offering free bids began on 1 December 2020, whereas the process for larger procurements of availability contracts started on 1 January 2021, with Vattenfall Eldistribution as the buyer. In total, six flexibility providers became members in the flexibility market during the first market season, of which four participated with free bids (Ellevio et al., 2021c). During January–March 2021, 2 276.4 MWh of flexibility was activated to meet the level of both total subscriptions and individual transmission grid stations. The calls for flexibility were particularly cautious in the first year, but they could have been double as much. It is noted that the level of the bids would not have been sufficient in a 10-year winter. The average activation price was SEK 485/MWh (EUR 46/MWh) and varied between SEK 200/MWh and SEK 5 000/MWh (EUR 19/MWh–EUR 475/MWh). Temporary subscriptions had a cost ranging from SEK 244/MWh (EUR 23.18/MWh) to SEK 246/MWh (EUR 23.37/MWh). Therefore, whenever there was the option of a temporary subscription, this was an effective price cap for the flexibility market.

In the second market season of the winter of 2021/2022, the number of market participants increased to eight, with five of them being aggregators, representing in total more than 2500 flexibility assets coming from all sectors (public buildings, residential sites, commercial sites and industrial sites). Most of the flexibility came from heat pumps of all sizes (small, medium and large heat pumps / district heating) and small EV chargers, with the remaining provisioned by back-up generation units (e.g. in hospitals), ventilation systems and home energy management resources. It is noted that, in Sweden, there are few cases of distributed generation (Ruwaida et al., 2022).

The seasonal availability bids for the winter of 2021/2022 ranged from SEK 100/MWh (EUR 9.95/MWh) to SEK 1 000/MWh (EUR 99.50/MWh). The maximum activation price ranged between SEK 860/MWh (EUR 81.70/MWh) and SEK 10 000/MWh (EUR 950/MWh). A total volume of 40.5 MW was offered, from which 10 MW was offered only as a 2-year seasonal contract (Ruwaida et al., 2022). It is noteworthy that, according to the publicly available market results, temporary subscription rights were either not permitted during

December 2021 by the TSO or were more expensive (by a factor of 1.19) than FSPs' flexibility offers, making the latter more competitive or the only available option for DSOs.

The survey results indicate that, in the future, reactive power flexibility services may be required, mainly avoiding the injection of reactive power from the distribution system to the transmission system. Market-based procurement can be an option, albeit with quite a different architecture, as, according to the stakeholders, long-term contracts would be more suitable than short-term trading for such services.

During the interviews, the project promoters raised the following points (among others).

- The main challenge facing DSOs in Sweden comes from the rapid electrification of all sectors of the economy (references were made to EVs, synthetic fuel production, and new industries such as fabrics, heat production, data centres and fossil-free steel), which has been taking place especially in the last 3 years and is expected to continue. Notably, this results in delays in new connections or, in extreme cases, in their denial. Network expansion will also be required in the transmission system, but, owing to the long times required, flexibility is seen as a measure to defer it, on the one hand, and as a means for serving the growing electrical demand in the short to medium term (i.e. until 2030) on the other.
- As regards the integration of flexibility into long-term network planning, the interviewees indicated that long-term contracts, like the seasonal contracts in sthlmflex, are more appropriate for this purpose, as they effectively aim to ensure the security of the supply.
- The specification of flexibility products is one of the main areas of experimentation by project promoters, during which it must be weighed up whether these specifications provide a clear business model for FSPs. Nevertheless, a coherent evaluation of different options has not yet been conducted.
- The project promoters were reluctant to impose penalties for partial delivery of flexibility at this stage of maturity of local flexibility markets. If these become relevant in the future, they should first be imposed on availability components, given that they effectively offer reliability services to network operators.
- As regards the required settlement period and MTU of flexibility products, the interviewees expressed the opinion that a 15-minute period (i.e. the same as the future imbalance settlement period in Sweden) is adequate for congestion management, as failures from overloading have long time characteristics (i.e. it takes a relatively long time to lead to a component failure). By contrast, for voltage regulation, flexibility should be much faster.
- Data ownership, in particular the power of attorney for measurement data when these come from meters not owned by network operators, posed a particular problem during the project. A standardised form is being developed in Sweden for addressing the issue.
- The need for measurement data standardisation has been identified as crucial. More generally, DSOs and TSOs in Sweden opt for standardisation based on the CIM protocol, but they understand that this could impose considerable transition costs for FSPs. On the other hand, the final vision is that CIM would be used in all electricity markets offering a harmonised framework, and thus would reduce barriers to market participation. Overall, the interviewees expressed the view that the transition to CIM harmonisation was going to be an evolutionary process.
- Regarding independent FSP–BRP relationships, the project promoters identified the key point as the coordination between the various markets. Proper coordination between local flexibility markets and the wholesale market could reduce the financial risk of BRPs by increasing their observability of independent aggregators' actions and giving them adequate room for hedging (e.g. in the wholesale intraday market). An ongoing dialogue between DSOs and the TSO is taking place in Sweden, and in 2022 a common view is expected to be developed regarding a product catalogue for flexibility services. A crucial point is that only upwards flexibility is requested currently by DSOs, as congestion management issues in Sweden come from increased electrical demand, as opposed to increased penetration of distributed generation (DG). This could be the reason why independent FSP–BRP relationships are not considered to require a strong regulatory framework at the moment; independent aggregator actions would lead to BRPs becoming long ([54]) (which currently would not pose a significant financial risk).
- The project promoters assess that there is substantial flexibility potential in their distribution systems. Barriers to mobilising this flexibility potential are not only technical but also organisational (e.g. for the

([54]) A BRP that is long in the imbalance settlement has a larger actual generation (or lower actual consumption) than its position after the gate closure of the Intraday market.

back-up generators in public buildings). An additional layer of complexity comes from the fact that FSPs have very different business models (e.g. an EV-charger aggregator versus an SGU), which also affects their preferences regarding flexibility product specification, organisation of the market, data management and settlement procedures.

The sthlmflex project will continue for 1 more year, after which the network operators will decide if they will turn it into a business-as-usual approach. For the overall developments of local flexibility markets in Sweden, it is noted that a new 2-year-long market project was set up in Gothenburg in February 2022 ([55]).

4.3. IntraFlex project

4.3.1. General Information

- Start date: October 2019
- End date: November 2021
- Country: United Kingdom
- Network operators involved: Western Power Distribution (DNO ([56]))
- Main web page: https://www.westernpower.co.uk/projects/intraflex

IntraFlex was a pilot project run by Western Power Distribution, a UK DNO, along with NODES and Smart Grid Consultancy from October 2019 to November 2021. The main goal of the project was to create a link between flexibility provision to network operators and wholesale market participation, with a particular focus on the imbalance risk undertaken by BRPs when independent aggregators activate flexibility. In this respect, two services specifically targeted at BRPs were initially envisaged:

1. an information service in which BRPs are continuously informed for the submitted flexibility offers in order to make their own informed decisions, in either the day-ahead or the intraday market;
2. an ‘auto-rebalancing’ function that would automatically balance any deviations from flexibility activation by trades in the wholesale intraday market ([57]).

However, during project execution, it turned out that the vast majority of BRPs were only interested in the information service, while considering the ‘auto-rebalancing’ function as having limited value under current volumes of flexibility activation, also given its complexity and risk. This was then dropped from the project (Western Power Distribution n.d.). Furthermore, FSPs did not express interest in subscribing in the information service, as they had no benefit to gain from it. Overall, the flexibility marketplace developed in the context of IntraFlex acted as a local flexibility market for the provision of congestion management only to the DSO with no balancing responsibility for FSPs.

4.3.2. Pre-qualification procedures

In the pre-qualification process, an FSP had to sign a membership agreement with the NODES market platform, accepting the latter’s rulebook, and had to undertake a test trade. FSPs had to register their assets, specifically the type of asset, metering point identification and location. Disclosure of the supplier in the registry has been left to the discretion of the FSPs. An end-to-end system testing then had to be made with one asset per FSP, based on which the buying network operator decided on approval (Western Power Distribution, 2021a). Ultimately, FSPs had to sign an agreement with Western Power Distribution that set the legal framework for the transactions between FSPs and the buying network operator (Western Power Distribution, 2021b).

Furthermore, the network operator verifies the legal trustworthiness of FSPs (e.g. convictions of serious offences and breaches of obligations relating to the payment of tax or social security contributions). The whole on-boarding process took approximately 4 months.

([55]) https://nodesmarket.com/another-nodes-market-goes-live-effekthandel-vast/
([56]) In this report, the terms DSO (Distributed System Operator), used in continental Europe, and DNO (Distribution Network Operator), used in the United Kingdom, are employed interchangeably.
([57]) In this respect, it is possible for the same flexibility activation to lead to two different trades: first, the trade of flexibility between the FSP and the DSO and, second, the trade of the respective energy to the wholesale intraday market by the BRP.

4.3.3. Flexibility products

In the IntraFlex flexibility marketplace, only an activation product was developed. Moreover, the flexibility product was defined by the DSO in terms of power (e.g. a demand reduction of 2 MW for a specific hour), rather than in energy terms (e.g. 2 MWh for the specific hour). Otherwise, referring to the same example, the FSP could provide in this time window a reduction of 4 MWh for half an hour, potentially leading to a network constraints violation (Western Power Distribution, 2020). Therefore, measurements with a granularity of 1 minute have been employed. The minimum bid size was 1 kW.

The flexibility product was divisible, but FSPs could also submit fill-or-kill and minimum quantity offers ([58]) (Western Power Distribution, 2020; Western Power Distribution, 2021c).

4.3.4. Market architecture

IntraFlex set up a continuous, pay-as-bid flexibility marketplace with gate closure 90 minutes before delivery. Trade was organised per congestion zone and the MTU was 30 minutes, that is, the same as the imbalance settlement period in the United Kingdom.

First, the DSO announced the forecasted flexibility needs 7 days in advance (i.e. at D-7), after which FSPs could submit offers ([59]). Flexibility services were requested only for weekday afternoons and evening peaks. The DSO set a price cap, i.e. effectively the DSO was submitting a bid sending at the same time notifications to FSPs. The timing of the DSO submitting its first bid was one of the main test parameters of the IntraFlex project, varying from 3 days before to close-to-real time. Another major design parameter was determining how the DSO bids would increase progressively in the lead up to real time (in case the required volume was not met by financially acceptable offers): different options included a linear increase in predefined steps in time (e.g. every day) and volume (e.g. GBP 50/MW/30 minutes in each step) to not predetermined bid increases in both time and price. The evaluation of offers was made solely on the basis of price.

According to the DSO analysis, longer pre-announcement periods led to competition in speed, favouring (relatively) large generation units. By contrast, when the DSO bids closer to real time, competition as regards price is promoted, favouring the participation also of FSPs with smaller and/or less predictable assets such as EVs.

4.3.5. Activation and settlement procedures

Offers by FSPs were submitted in the NODES market platform either manually in a web portal or through an API. The activation of flexibility was made by FSPs after a dispatching signal by the market platform (NODES). Metering data were gathered and sent to the market platform through an API based on the same design as the Flexible Power initiative (see Section 4.7.1) for presenting a low barrier to FSP participation. In most cases, readings from the connection point meter were used, but, in certain cases, FSPs opted for assets' submeter measurements (especially for EVs). It is noted that the development of the necessary smart meter infrastructure was a particular task undertaken by the network operator in the context of this pilot project.

Settlement was done separately for every single minute of the delivery period.

The baseline methodology defined by the network operator employed a daily profile with 48 half-hourly periods, which was a significant departure from the current practice in the majority of UK flexibility auctions. The baseline for each period was calculated from the average of the prior 5 completed weekday measurements for that same period. The calculation was made on a daily rolling basis. Recognising that there may be exceptions for some FSPs, FSPs had the option of either proposing an alternative method to more accurately predict their baseline or defining explicitly in the NODES market platform the baseline of their portfolio; the latter turned out to be their preferred option (Western Power Distribution, 2020; Western Power Distribution, n.d.).

In the case of partial delivery of flexibility, there was no penalty, but there was a reduction in compensation according to the following rules (Western Power Distribution, 2020):

([58]) A fill-or-kill order is an order that must be accepted in its entirety. A minimum quantity offer is an order in which a specific minimum quantity must be accepted.

([59]) FSPs making offers proactively (i.e. without knowledge of DSO flexibility demand) is identified as a characteristic of liquid markets in the project documentation. Nevertheless, Western Power Distribution pre-announces the required flexibility volumes in order to attract offers owing to the relative immaturity of flexibility services provision. With variable in time and price bids, Western Power Distribution tried to induce competition in price.

— 100 % payment for delivery at 95 % or above;
— a reduction of 3 % in payment for each percentage under 95 %;
— no payment for delivery below 63 %;
— no additional payment for over-delivery.

4.3.6. Results and lessons learnt

The IntraFlex project ran in two distinct trials. Six FSPs participated in each trial. Overall, 1 422 trades took place, mostly in the second trial, with a total procured flexibility volume of 831 MWh. Offers ranged from 7 kWh up to 5.1 MWh, while prices were in the range of GBP 60–360/MWh (EUR 72–432/MWh ([60])).

A significant outcome was that, irrespective of the test parameters, the total requested flexibility volume was never provided in full. This was mainly because, in certain periods, supply did not cover demand (given also the price cap set by the DSO). In total, 73 % of volume was traded and 80 % was delivered (Western Power Distribution, 2021c). One reason identified for the partial delivery was the absence of financial penalties for under-delivery.

Regarding the issue of the information service, the interviewee expressed the opinion that FSP participation should remain voluntary. A key outcome of the project was that, under current conditions, the auto-rebalancing service was not of interest. This is, first, because of the low flexibility volumes with respect to BRPs' portfolios and, second, because the flexibility services required at the moment are in the upwards direction and BRPs do not face a significant financial risk by being long under current conditions in the wholesale balancing market. Nevertheless, according to the structured interview, this may change as flexibility volumes increase in the future and/or imbalance prices change.

A significant positive outcome of the project for the buying network operator was the ease with which the APIs that were developed were integrated into the NODES market platform. The employment of standardised APIs is therefore seen as the main way forward for interoperability.

A particular barrier to the development of a more sophisticated flexibility market architecture in the United Kingdom is the problematic roll-out of smart meters – even though some new flexibility assets such as EVs have the required metering infrastructure – owing to the specific incentives provided. As regards EVs, experience during the project showed that a pool of around 50 units permitted an effective forecasting of its flexibility potential by the FSP (Western Power Distribution, 2021c).

Another criticality raised in the interview was the necessity of market architectures that facilitate value stacking. The experience of the network operator shows that the value of flexibility for services exclusively to the distribution system cannot cover the overall costs of flexibility assets, so as to make for a viable business case on their own.

In contrast with the current, mainly long-term, procurement of flexibility in the United Kingdom, the interviewee expressed the conviction that shorter procurement timelines offer advantages in terms of economic efficiency and market participation by smaller flexibility assets such as EVs. In this context, the integration of local flexibility markets within the wholesale market is an inevitable final step, but the model is unknown at present. The high price of balancing capacity in the wholesale market at present, especially for dynamic containment reserves, may limit participation in local flexibility markets by setting a high price floor for flexibility services (Western Power Distribution, 2021c).

Finally, Western Power Distribution is going to continue developing innovation projects on flexibility, with future work focusing on market architectures fostering value stacking for FSPs, implementing continuous forecasts of flexibility needs into the market, and gathering experience with heat pumps. It was acknowledged in the interview that the regulatory framework in the United Kingdom facilitates innovation by DSOs. Furthermore, it is expected that the next budgetary period will focus more on implementation than on experimentation.

4.4. NorFlex project

4.4.1. General Information

— Start date: 2019

([60]) Considering an exchange rate of GBP 1 = EUR 1.20.

— End date: 2022
— Country: Norway
— Network operators involved: Agder Energi (DSO), Glitre Energi (DSO), Statnett (TSO)
— Informative web pages:
  - https://nodesmarket.com/case/norflex-tso-dso-making-local-flexibility-available-to-mfrr/
  - https://www.ae.no/en/our-business/innovation/norflex-prosjektet2/what-is-norflex/
  - https://www.statnett.no/en/about-statnett/research-and-development/our-prioritised-projects/norflex/

NorFlex is an umbrella demonstration project that is being run from 2019 to 2022 by two Norwegian DSOs (Agder Energi and Glitre Energi) and Statnett, the national TSO. The main focus of the project is the activation of flexibility for network expansion deferral and congestion management in the distribution system, while residual flexibility is aggregated to offer mFRR services to the TSO ([61]). The pilot project is divided into three development phases: the proof of concept phase in 2019–2020, the proof of market phase in 2020–2021 and the market ready phase in 2021–2022. Only during the final phase has flexibility trading taken place. During the first phase, successful data exchanges were established, while, in the second phase, the necessary tools for the DSOs (congestion forecasting) and FSPs (asset optimisation) were developed.

Independent aggregators participate in the pilot project thanks to an exception from the current regulatory framework in Norway (NODES, 2022).

4.4.2. Pre-qualification procedures

Any flexibility asset must register in a flexibility data register (FDR) ([62]) before placing offers in the flexibility market. The FDR is common to both the TSO and the DSOs for achieving a coordinated, efficient and secure active system management process, given that a flexibility resource can deliver multiple flexibility services to network operators. The concept of an FDR is central to the vision of Norway's network operators on flexibility (Pedersen, 2021a). It is important to note that the FDR belongs to the regulated domain. It is also clarified that the definition of a flexibility asset in the NorFlex project extends below the connection meter, down to individual device level (e.g. a floor heater).

Owing to the pilot nature of the NorFlex project, the developers chose not to impose any pre-qualification processes other than registration in the FDR, the successful upload of metering data to it and effective data communication with the trading platform (NODES). Therefore, all registered flexibility assets with a nominal capacity above 1 kW qualify for testing in the NorFlex pilot. A particular focus of the project is testing the technology that the aggregators use to collect data from flexibility assets.

4.4.3. Flexibility products

Both availability and activation products are traded in the NorFlex marketplace.

Availability products are procured 1 month in advance and are of weekly duration. Both the availability and the activation price are predetermined by the buying party (DSO) and reflect the investment deferral opportunity cost (Pedersen, 2021a).

The minimum bid size for both availability and activation products is 1 kW, and bids are divisible.

4.4.4. Market architecture

The NorFlex project set up a marketplace in which only network operators procure flexibility, with the DSO having precedence over the TSO. Trading for flexibility services to the DSOs is organised per congestion area in the 132 kV grid downwards. After the DSOs have covered their needs, the residual flexibility is made available to the TSO mFRR market (from the winter of 2021/2022) in minimum blocks of 1 MW.

([61]) Note that, in the Nordic countries, redispatching and countertrading are undertaken based on offers submitted in the mFRR order book. Therefore, residual flexibility passed to the mFRR market can be used for both redispatching in the transmission system and system balancing.

([62]) For information on the FDR (or flexibility resources register) concept, see CEDEC et al. (2019).

Availability products are procured 1 month in advance. For activation products, continuous trading is employed. Trading starts after the buying DSO publishes on the marketplace the volume and bidding price for the next week for the time window 7.00–19.00 (for the winter of 2021/2022) (Pedersen, 2022). Moreover, in the winter of 2021/2022, flexibility trading was also tested during night hours owing to congestions in the distribution system caused by high levels of EV charging in response to wholesale price differentials. These price differentials were pronounced in the winter of 2021/2022 owing to the energy crunch situation throughout Europe. Announcements are made only to the marketplace and there is no dedicated communication to FSPs. The aggregators can place bids up to 2 hours before activation, while the buying network operator can update its bids during the trading period. The definition of the gate closure time 2 hours before delivery aimed, among other things, to ensure coordination with the wholesale balancing market, to which uncleared flexibility offers are passed.

The MTU is 60 minutes, which is equal to the current imbalance settlement period in Norway. The clearance of offers is made based solely on price.

There is not an established TSO–DSO coordination platform at the moment. Work is ongoing on an additional service at the FDR through which the TSO and DSOs will exchange information when they expect that flexibility activation may affect parts of the network outside their responsibility.

4.4.5. Activation and settlement procedures

Activation of cleared offers in the order book takes place automatically by the buying network operator without pre-announcement (Pedersen, 2021b).

The measurement period is 1 minute, and settlement is made based on this time granularity. The buying network operators, through the FDR, also record measurements both 2 hours before flexibility activation and 2 hours after activation to better assess rebound effects, but they would like to extend this to continuous recording to be able to assess baselines better in the future (Pedersen, 2021a).

Given that assets in the NorFlex flexibility market are defined at device level, measurement from submeters are employed. Metered data are uploaded to the FDR, while the baseline is uploaded by the FSPs in the market platform 24 hours before activation at the latest. Nevertheless, the baseline can be adjusted by the aggregator up to 2 hours before activation (i.e. at gate closure).

Remuneration of availability products is made subject to the submission of activation offers. No penalties apply for partially delivered flexibility services (for both availability and activation products), but reduced compensation below 80 %. When flexibility provision is less than 50 % of the cleared offer, the remuneration drops to zero. There is no additional remuneration for over-delivered flexibility.

Balance responsibility is undertaken by the BRPs of the flexibility assets. In the future, compensation by the FSP to the BRP for the pre-bought energy by the latter is expected to be handled through the FDR.

4.4.6. Results, lessons learnt and future developments

In 2021, 28 weeks of trading took place in the pilot project. Most trading was fictional, in the sense that the purpose was testing the trading process rather than solving actual congestions, which is only the case for winter of 2021/2022. From 2022, flexibility offers that are not used by the DSOs are being forwarded to the wholesale balancing market.

Currently, 10 FSPs participate in the NorFlex market, representing all types of end-customers (residential, commercial and industrial) (NODES, 2022). Flexibility assets include batteries, electric boilers, ventilation systems, greenhouses, EV chargers (alternating current (AC) and direct current (DC)) and other household devices. The project developers aimed to include larger industries during the winter of 2021/2022. The liquidity in the ShortFlex continuous market has proven to be larger than in the LongFlex owing to both the supply side (the characteristics of the flexibility assets in participating FSPs' portfolios) and the demand side (larger variability of power flows in the network forcing the buying network operators to update their flexibility needs closer to real time). On the other hand, the price of flexibility in the ShortFlex was significantly larger than in the LongFlex.

According to the publicly available results ([63]), 225 MWh of flexibility was procured in the NorFlex market in 2021, with a weighted average price of NOK 6 593/MWh (EUR 659.3/MWh ([64])).

Based on the survey results, network operators foresee that there will potentially be the need for steady-state voltage control and fast reactive current injection flexibility services in the future.

Issues raised during the interview included the following (Pedersen, 2021a).

- Congestions are increasing in the Norwegian network, both at distribution and at transmission level. This is because of three main factors: (1) the electrification process, especially in the transport sector, where fast-charging stations pose a particular challenge, followed by new battery factories, data centres and green hydrogen facilities; (2) an increase in wholesale exports; and (3) new wind capacity. In addition, the network in Norway is quite old and requires modernisation.
- According to the interviewee, market-based procurement of flexibility should be the preferred option if there are resources available. Regulated tools, such as special network tariffs and flexible contracts offered in exchange for the right to disconnect demand at critical situations, should be used only as a back-up solution.
- The preferred architecture for a flexibility market is a marketplace in which both DSOs and the TSO can procure flexibility services from distributed sources. The interviewee were of the opinion that, for the mid-term (i.e. for the next 10 years), direct participation of distributed resources in the TSO's wholesale balancing and redispatching markets may prove a costly direction, owing to the current lack of observability of such assets by TSOs. Instead, procurement of services by local flexibility markets, also serving DSOs, would be easier (i.e. a cascade market architecture).
- The lack of standardisation regarding data format and communication protocols is a significant barrier to the development of local flexibility markets, introducing complexity and additional costs. This does not concern only FSPs but extends also vertically, affecting the data exchange between DSOs and national TSOs. Harmonisation to CIM is the long-term solution, but at present APIs are a practical way forward.
- Adaptation of FSPs' systems to the two APIs employed in the NorFlex project, one for the NODES market platform and the other for the FDR, proved both lengthy (1 year) and costly. Furthermore, in the case of one FSP, it was unsuccessful. It is noted that the costs in all cases were undertaken by the project promoters.
- A second challenge in the development of the flexibility market was grid tools for congestion forecasting at DSO level. This required a considerable effort in increasing the observability of the distribution network in which the pilot project was taking place, with the installation of 8 000 sensors. The whole process took 1 year.
- FSP business models are in development. The challenges faced by them include both how to value stack between separate markets and the development of the required intelligence for portfolio optimisation, including better prediction of their baselines. Moreover, trading automation by FSPs is currently less advanced than that of network operators, who already deploy robots for setting bids.
- Overall, technological solutions for the various systems (e.g. grid forecasting and aggregator optimisation tools) do exist, but they are still expensive, which has a negative impact on the business case. The interviewees expressed the opinion that financial support should be provided for building the required intelligence for flexibility provision, similar to the support given for RES development.
- On baseline methods, the establishment of baselines for heating loads proved particularly challenging. Project promoters are still open to different options and they are testing different models with different time resolutions. An alternative to FSP schedule declaration could be baselines being forecasted in the FDR and then proposed to FSPs. For this, continuous measurement recordings from flexibility assets complemented by other parameters (e.g. temperature) would be needed.
- Establishing baselines proved easier for flexibility coming from households, as opposed to office and public buildings, because data availability on their consumption characteristics is high even at device level (e.g. floor heating, water heaters and EV chargers), as many suppliers already collect these data. Medium-sized and large industries already offer flexibility to the wholesale balancing market and have well-established

([63]) https://nodesmarket.com/norflex/
([64]) Considering an exchange rate of NOK 1 = EUR 0.10.

baseline forecasts. Overall, these resulted in flexibility offers coming from FSPs having in their portfolio industrial sites and/or (pools of) households being cheaper.

- Regarding penalties for partially delivered flexibility, these should probably be introduced in the future, particularly for availability products.
- Meter data, as well as baselines, should be collected and validated in the FDR, which is in the regulated domain, as opposed to the market platform, which is in the commercial domain. The main argument for this is that congestion management and balancing are regulated processes run by network operators. The FDR could undertake all data and intelligence processes for settlement verification, while financial transactions would be under the responsibility of the market platform. In addition, a solid method regarding the compensation between independent aggregators and BRPs could be established in the FDR. In fact, this is the only option, according to the interviewee. Nevertheless, the interviewee questioned the value of such a process for flexibility activation by small assets (e.g. below 100 kW) or the BRP's actual interest, given the natural variability of demand. Finally, the FDR could be the basis for the development of additional flexibility products, such as for voltage control, given that it is the central point where all necessary technical characteristics (location, type of asset, nominal capacity, etc.) and pre-qualification compliance of assets are registered.
- It is accepted that flexibility for solving congestions in the distribution system will be priced higher than flexibility provision for system balancing. How high this price differential can go is one of the parameters about which the DSOs want to accumulate experience through the NorFlex pilot project. In addition, it is expected that competition for services by flexibility assets connected to the distribution system will develop in the future between DSOs and the TSO.
- The vision of the project promoters is heavily based on automation, as flexibility will be traded closer to real time and with shorter MTUs, in line with the developments in the wholesale market.
- The national regulatory authority follows the project very closely and wants the project promoters to provide recommendations, especially on the FDR and on overall data management considerations such as cybersecurity, privacy and end-customer consent.

4.5. GOPACS

4.5.1. General information

- Start date: December 2018
- Status: ongoing
- Country: Netherlands
- Network operators involved: TenneT (TSO), Coteq (DSO), Enexis (DSO), Liander (DSO), Rendo (DSO), Stedin (DSO), Westland Infra (DSO)
- Website: https://en.gopacs.eu/

GOPACS was one of the first TSO–DSO coordination platforms implemented for solving network congestions. GOPACS is integrated into the existing sequence of wholesale markets by resourcing flexibility from existing market platforms. So far, the only collaborating market platform has been the Energy Trading Platform Amsterdam (ETPA) ([65]), but, from May 2022, the participation of EPEX SPOT ([66]) was also announced (Stufkens, 2022 ; EPEX SPOT and GOPACS, 2022).

All network operators in the Netherlands participate into the initiative, albeit with significantly differing levels of flexibility service procurement through the platform, with the main buyers being TenneT (first by a large extent) and Liander (second) ([67]). In the only currently connected wholesale market platform (ETPA), it is mainly medium-sized and small commercial customers that operate. This platform represents only a small volume of the total wholesale trade in the Netherlands, but the participation of EPEX SPOT, by far the largest power exchange in the Netherlands, is going to change that.

([65]) https://etpa.nl/
([66]) https://www.epexspot.com/en
([67]) The market data is available online (https://idcons.nl/publicclearedbuckets#/clearedbuckets).

4.5.2. Pre-qualification procedures

To participate in the intraday congestion spread (IDCONS – see the next section for the definition), market parties must be connected to a trading platform that supports the product. In addition, they must sign the IDCONS participation agreement (Stedin et al., 2019). After having received confirmation of completion of the pre-qualification process by email, the relevant market party and the relevant trading platform receive confirmation from GOPACS.

The IDCONS participation agreement contains:

— a declaration of acceptance of IDCONS product specifications;

— a declaration of acceptance of IDCONS privacy conditions;

— the name of the trading platform at which the market party wants to place orders for IDCONS;

— a list of the European article numbering (EAN) codes ([68]) that the market party wants to use on the trading platform for IDCONS.

After having received the IDCONS participation agreement, grid operators have to first process the new EAN codes internally before orders with these EAN codes can appear as IDCONS. This process includes an evaluation of the impact of activated flexibility on the network. The pre-qualification process takes a maximum of 5 working days. After completion of this registration, the market party receives a confirmation by email.

The pre-qualification process does not contain an explicit check of the consent by the contracted party or customer of the specified EAN codes. Obtaining consent is the responsibility of the FSP, as is coordination with the BRP for the connection.

Finally, the pre-qualification process does not include physical (ex ante) tests (Stedin et al., 2019).

4.5.3. Flexibility products

A fundamental feature of the GOPACS architecture is that the buyer grid operator effectively undertakes balancing responsibility in respect to the system. Therefore, any procurement is a combination of two orders (a buy order and a sell order), packaged into a standardised product: IDCONS (Trienekens, 2020). The buy and sell orders have the same format as intraday wholesale orders (simple bids of 15 minutes or 1 hour), and the orders agree in terms of the starting time, volume and duration, but are in different areas. For example, when a congestion occurs in one part of the network due to high load, one energy sell order will be procured by GOPACS in that part of the grid. At the same time, in a non-congested area, an energy buy order will be activated. As such, system imbalance is avoided. The price of the energy sell order will be higher than the price of the energy buy order (otherwise the trade would take place in the wholesale intraday market). The network operator that requests the flexibility pays the spread between the orders. There are no minimum or maximum prices or volumes defined for IDCONS.

It is noted that DSOs in the Netherlands have long-term bilateral contracts with FSPs that can also be available to the TSO. The central idea behind the IDCONS product specification (i.e. keeping system balance when activating flexibility for congestion management) is also retained in the case of long-term contracts (Stufkens, 2022).

4.5.4. Market architecture

GOPACS, as already mentioned, is not a market platform, but it uses orders in existing wholesale electricity markets. The ETPA is the first market platform to have joined GOPACS. Participating parties trade electricity by placing buy orders and sell orders in the ETPA market platform.

In the ETPA, the flexibility offers that can be employed in GOPACS are seen as a subset of the wholesale continuous intraday order book. FSPs have the option to offer the same flexibility at two different prices by placing two orders (e.g. one portfolio offer for the intraday wholesale market and a second offer with locational information, the EAN codes, which is necessary for participation in GOPACS). The flexibility provider is responsible for avoiding double activations, and verification of compliance is conducted by the market platform (i.e. the ETPA). Therefore, in principle, network operators and market parties (BRPs) compete for the same flexibility, but, effectively, only offers that are not financially acceptable by the latter become available for the former (assuming that both have the same level of trading automation and speed). The MTU in GOPACS is

([68]) The EAN code is a unique number that identifies a connection to the electricity network.

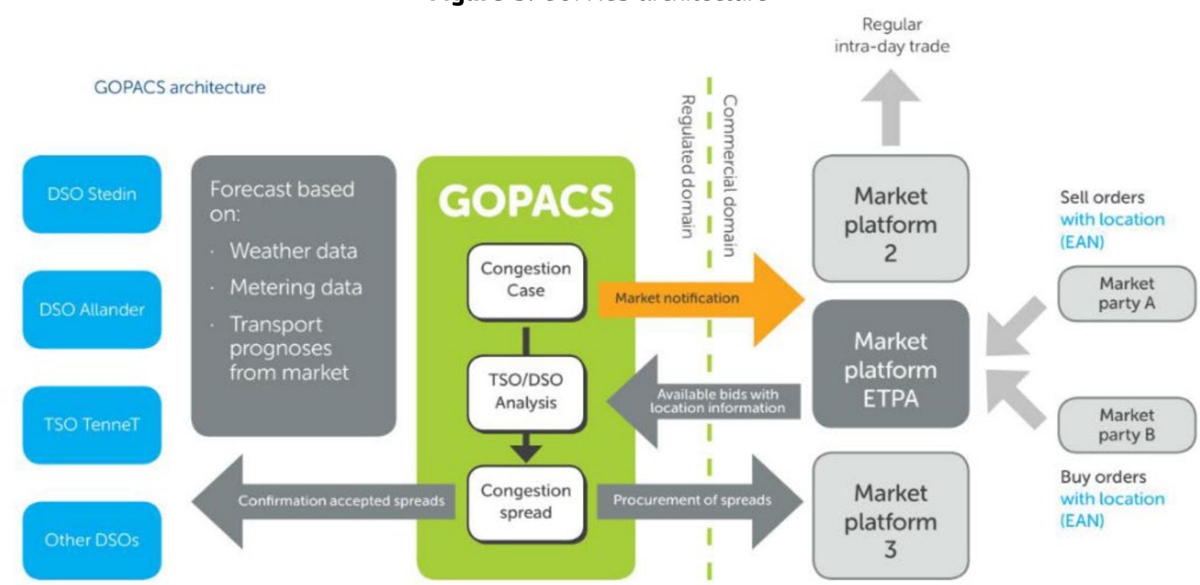
15 minutes, the same as in the wholesale intraday market. Like the wholesale intraday market, GOPACS employs pay-as-bid pricing and acts as a continuous procurement mechanism.

Grid operators pre-announce their flexibility needs (volume, time, duration and direction) to solve congestions in specific areas (defined with postal codes and/or regions) less than 24 hours before activation, and sometimes even only 6 hours in advance (Stufkens, 2022). They use their own tools and processes to determine congestions and to evaluate the potential contribution of orders with location indication to solve the transport restriction. There are some formal fixed congestion areas, but network operators can also form an ad hoc IDCONS for solving congestions outside these (Stufkens, 2022). In all cases, along with location, the fundamental criterion for the creation of an IDCONS is the price differential between the sell and the buy orders. Furthermore, the grid operators prevent an IDCONS from causing or aggravating transport restrictions elsewhere in the grid when they create them.

The nomination of orders as part of IDCONS is done according to the rulebook of the connected wholesale trading platform. Therefore, cleared orders as part of an IDCONS are administered as a trade between the two market parties involved. This means that the general rules, processes and agreements for the nomination of such a trade of the relevant trading platform are applicable. FSPs participating in the ETPA are charged with an entry fee, a monthly fee and a fee per interchanged MWh. Grid operators owe a fee to the market platform for the use of IDCONS.

Figure 3 provides a schematic view of the GOPACS architecture, while Figure 4 depicts the grid and market interactions.

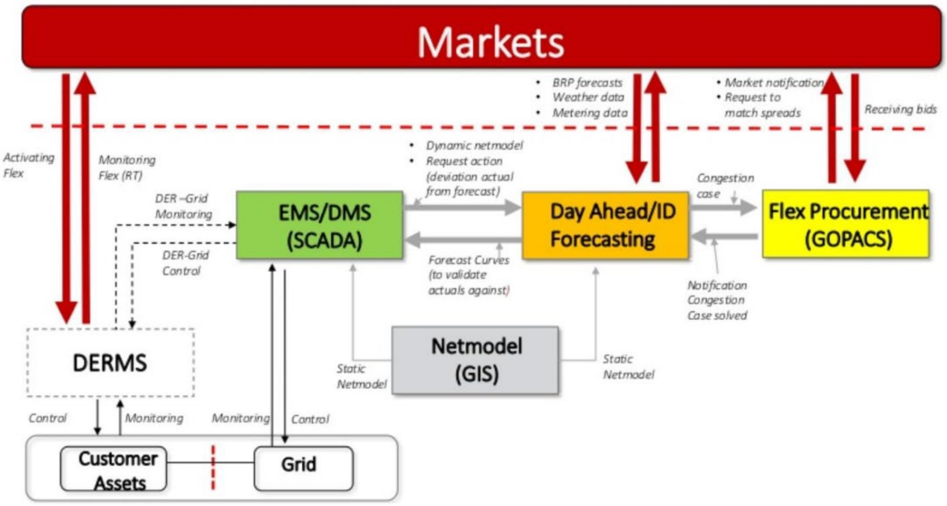
Figure 3: GOPACS architecture



Source: EUniversal UMEI deliverable D2.1 ([69]).

([69]) https://euniversal.eu/deliverables/

Figure 4: Grid and market interactions in GOPACS



RT: Real-time
EMS: Energy Management System
DMS: Distribution Management System
SCADA: Supervisory Control and Data Acquisition
DERMS: Distributed Energy Resources Management System
GIS: Geographic Information System
ID: Intraday

Source: Presentation from Stedin ([70]).

4.5.5. Activation and settlement procedures

Given that GOPACS is not a market platform as such, but trading is done through a wholesale intraday marketplace, activation and settlement procedures follow the provisions of the latter. In principle, settlement is made on a congestion area portfolio basis, even though, in practice, most FSPs are rather small and have only a single connection point (Stufkens, 2022).

4.5.6. Results and lessons learnt

So far, the main network operator making use of GOPACS is the Dutch TSO (TenneT), with Liander (DSO) coming in second. Aggregate results for all network operators that have procured services through GOPACS are provided in Table 7. The procurement unit flexibility cost for the DSO Liander is approximately 1.5 the cost for the TSO (TenneT). This is mainly due to lower liquidity for solving congestions in specific parts of the distribution network.

To date, around 500 FSPs have submitted offers for GOPACS. Generally, they are small in size and mostly represent commercial, residential and greenhouse facilities with a portfolio capacity lower than 60 MW (Stufkens 2022).

Table 7: Aggregate results for the flexibility services procured through GOPACS for 2021

	TenneT	**Liander**	**Enexis**
Total activated flexibility volume (MWh) (*)	142 997.6	111.3	24.8
Total cost (EUR, thousands)	45 014	52	16
Average cost of activated flexibility (EUR/MWh)	314.8	467.2	645.2

(*) In the calculation, only the upwards volume is considered.

Source: JRC calculations based on the costs for using IDCONS for redispatch ([71]).

The following points were raised in the interview (Stufkens, 2022).

([70]) https://www.slideshare.net/dutchpower/3-peter-hermans-stedin
([71]) https://idcons.nl/publicexpenses#/expenses

- The main drive behind the development of GOPACS was to exploit the significant flexibility resources in the distribution network. When the platform was developed, only the TSO had need of such services, but DSOs were soon likely to encounter similar challenges in their network. The factors behind the increasing congestions in the Netherlands are electrification and the expansion of the capacity of variable RESs (vRESs: wind and solar photovoltic power generation units).
- The retainment of balance at system level was central to the market architecture of the GOPACS initiative and this will remain so for all congestion management processes in the future. Furthermore, an intraday market was preferred, as the project promoters chose to procure flexibility as close as possible to real time when congestions occur.
- Standardisation of flexibility products and procurement processes also for long-term contracts is one of the main goals of the network operators roadmap on flexibility. A second main goal is coordination between different markets, and more specifically the procurement of flexibility coming from assets in the distribution system for congestion management and for system balancing. It was noted that the Equigy platform ([72]), which aims to facilitate the provision of system balancing services by DERs, is already rolled out in the Netherlands. It was also noted that the rules for redispatching, including from sources in the transmission system, are going to change in 2022 in the Netherlands, which adds another challenge to the overall coordination effort. All in all, the interviewees had the opinion that the integration of the different markets for network services will take time, even though the need is clear.
- Processes by DSOs regarding security analysis in their networks are improving. The TSO is already at an advanced stage with the capability of running such analyses every 5 minutes. DSOs do not use the common grid model, and the interviewee' opinion was that they are still quite far from CIM harmonisation. Therefore, coordination between DSOs and the TSO in GOPACS is not undertaken in a particularly automated way, and each network operator is separately responsible for assessing the impact of an IDCONS formation in its own area.
- Regarding the required network services from DERs in the next 5 years, the interviewees identified frequency response as the most important one. Black-start capability is provided by large units and there is no additional need, while inertia response is seen as a potential requirement only for the far future.
- At TSO level, flexibility is incorporated as an alternative to classic network expansion, with a significant assessment criterion being the time to materialisation of each option.

4.6. enera Flexmarkt

4.6.1. General information

- Start date: February 2019
- End date: June 2020
- Country: Germany
- Network operators involved: TenneT (TSO), Avacon Netz (MV and HV DSO), EWE NETZ (MV and LV DSO)
- Main website: https://projekt-enera.de/

The enera Flexmarkt, which focused on network congestion management, was developed in the context of the enera research programme under the smart energy showcase — digital agenda for the energy transition (SINTEG) funding programme ([73]). The participating grid operators were EWE NETZ (MV and LV DSO), Avacon Netz (MV and HV DSO) and TenneT (TSO). The market platform was provided and operated by the EPEX SPOT power exchange.

The project has been rolled out in the counties of Aurich, Friesland and Wittmund. A particular characteristic of the local power system is the very high renewable penetration, reaching 235 % of the local electricity demand. Therefore, a particular goal of the project has been the reduction of renewable curtailment for alleviating network congestions and of the associated costs for network operators. This contrasts with other local flexibility markets reviewed in this report, in which the main source of congestions was consumption, rather than vRES production.

([72]) https://equigy.com
([73]) https://www.sinteg.de/en/

4.6.2. Pre-qualification procedures

First, flexibility providers had to register their assets into a FDR. The pre-qualification process included only the technical characteristics of flexibility assets (mainly nominal capacity and location). In principle, no minimum nominal capacity limits of flexibility assets were established, but, in practice, the participating assets were relatively large (more than 500 kW) (Gertje, 2021a). Responsible for the whole pre-qualification process was the connecting network operator. Overall, the pre-qualification process was rather light owing to the pilot nature of the project (Gertje, 2021a).

4.6.3. Flexibility products

Flexibility products for short-term congestion management (up to TSO level) were traded in the enera marketplace. The European power exchange EPEX SPOT operated the enera Flexmarkt using the same platform as the existing intraday market, with small modifications, as market processes were quite similar. Using a well-known market platform also led to low market entry barriers for flexibility marketers. Fifteen-minute and 1-hour energy (activation) products were traded. In principle, there was no nominal minimum bid size, but, in practice, the lowest bid was 50 kW (Gertje, 2021b). Bids were divisible. It should be noted that the unit compensation for forced renewable curtailment paid by network operators represented an effective price cap for the activation of flexibility.

4.6.4. Market architecture

Trade was organised in 23 different local market areas, each one corresponding to a local transformer. The maximum voltage level per local market area was 20 kV, but flexibility activations inside each area could be used for solving congestions up to transmission level (i.e. all upwards network operators were also included as buyers of flexibility) (Gertje, 2021b). FSPs offered flexibility on a portfolio basis per local market area.

Flexibility trading was starting when a network operator was predicting a congestion, and a notification was sent to FSPs through the market platform and via email. At the same time, FSPs could also place offers, irrespective of whether or not there was an announcement by network operators. Notification of flexibility demand by network operators depended on grid status forecast. A relatively good view on potential congestions was possible 3 days ahead, but obviously the forecast became better closer to real time. On the other hand, flexibility offers closer to real time were becoming more expensive, so there was a trade-off for buying network operators. Overall, notification of flexibility demand took place between 3 days and 1 hour ahead (Gertje, 2021a).

Nominally, the gate closure time was 15 minutes before delivery, but most offers were cleared by network operators some hours before (Gertje, 2021b; Lahmar 2021a). The enera Flexmarkt operated based on continuous trading, similar to the intraday wholesale market. The MTU was 15 minutes. There was an order book for each of the 23 local market areas, which was different from the order book of the wholesale intraday market.

The evaluation of offers was made solely based on price. However, before the clearing of an offer, negotiation between the buying network operator and the FSP could be made: the network operator either accepted the offer or made a counteroffer. In the latter case, the FSP had to accept, deny or make a counteroffer in turn (Gertje, 2021a). In practice, successful offers were mostly cleared without further negotiation and thus the market operated mostly like having a pay-as-bid pricing mechanism.

The regulated penalty paid by network operators when RES are forcefully curtailed for solving congestions effectively played the role of a price cap in the enera local flexibility market. Even though the rules governing the calculation of this penalty are publicly known, the exact value is known ex ante to market participants because this depends on the exact RES category that is curtailed (Gertje, 2021a). Given that regulated RES curtailment was always available for solving congestions, the main aim of the enera Flexmarkt project was economic efficiency.

Coordination between network operators was made in a cascading top-down direction: the upstream system operator informed its downstream counterpart about the amount of power to procure via the marketplace and notified its congestions. This information was processed by the downstream operator, which returned the applicable capacity restrictions (i.e. the maximum amount of power that the upstream operator was able to procure from each local market area) (enera, 2020). This also effectively meant that the downstream network operator had priority regarding the utilisation of flexibility potential in its network (this is also the case for the regulated redispatch procedure in Germany). The coordination processes between network operators were conducted in isolation from the market platform and it was done in a separate grid prognosis tool developed in the enera research project (Gertje, 2021a).

4.6.5. Activation and settlement procedures

Activation was made by the FSPs after clearance of their orders in the enera Flexmarkt. Communication was made through the market platform.

Settlement was based on a comparison of the metered input (or output) of the flexibility assets against a schedule provided by the flexibility providers per local market area, which acted as a baseline (Gertje, 2021b). The measurement and settlement period was 15 minutes. In the context of the enera project, an ex post methodology for the identification of possible inc-dec gaming was also developed (Stein, et al., n.d.).

Data communication was addressed in a centralised way. All of the required data, such as measurements, baselines, cleared offers and RES forecasts, were delivered to a centralised data hub: the Smart Data and Service Platform (SDSP). The platform was run by an independent data manager. This was an intentional choice to ensure that no particular power network operator owned all of the data. In the SDSP, all of the relevant tools for the functioning of the flexibility market were built, such as the FDR, the grid prognosis tool, the verification of flexibility activation and the market platform (Gertje, 2021a).

Participation of independent aggregators was permitted in the enera Flexmarkt. The balance responsibility fell on the BRP of the flexibility assets, which was then usually self-balancing in the intraday wholesale market. On the other hand, the FSPs were compensating suppliers for the pre-bought energy by the latter. The level of compensation was defined by bilateral agreements as per the German law provisions applicable at the time (Lahmar, 2021b).

In the case of partial flexibility delivery, compensation dropped to zero, while there was no additional compensation for over-delivery. In the contractual agreement for participating in the enera Flexmarkt, penalties were also set for partial delivery of flexibility, but these were set to zero owing to the pilot nature of the project (Gertje, 2021a).

4.6.6. Results and future developments

Overall, more than 4 000 orders were submitted and 130 transactions took place in the enera Flexmarkt (EPEX SPOT, 2020). The flexible capacity participating in the project reached 360 MW by six FSPs. Flexibility resources ranged from wind farms, biogas plants, photovoltaics and storage devices to power-to-gas, power-to-heat and gas compressors (enera, 2020). Flexibility from the demand side was around 50 MW owing to the economic characteristics of the area in which the pilot project took place (relative lack of big energy consumers) (Gertje, 2021a).

The enera Flexmarkt remained a pilot project and was not continued. A key reason for this were the regulatory decisions regarding redispatching in Germany. Under current developments, redispatching remains a regulated process in which demand cannot participate. The enera partners have submitted a proposal for a hybrid scheme in which regulated redispatching and non-regulated assets (demand facilities and non-remotely controllable distributed generation (DG) of less than 100 kW) offering their flexibility services based on free offers would co-exist (enera, 2020). In June 2021, the Ministers Of Economics of the German Federal States adopted a decision calling for the market-driven development and use of flexibilities in the distribution grid ([74]).

During the interview with the representative of EWE NETZ, the following interesting points were made.

- There was difficulty in recruiting FSPs. The flexibility market made a weak business case for them.
- Congestion management is an almost structural issue in the German network, particularly at transmission level. Network operators face significant costs, especially as regards compensation to RESs, which must be curtailed. Enhancing the economic efficiency of redispatching actions was one of the main reasons behind the development of the enera Flexmarkt project.
- For mature local flexibility markets, penalties should be imposed in the case of partial delivery.
- According to the interviewee, the project was quite a success. However, the possibility of inc-dec gaming is considered a significant issue posing a high risk, which possibly makes a rule-based approach to redispatching safer. The risk of inc-dec gaming is further aggravated by the fact that the network operator

([74]) https://nodesmarket.com/germany-master-plan-for-flexibility-in-brandenburgs-distribution-networks/

must develop a forecast for vRES flexibility assets and cannot rely solely on baseline declarations by the FSPs.

- The regulatory derogations provided in the context of the SINTEG research programme were fundamental for the development of the enera project. Nevertheless, there could be more room for innovation.
- All relevant resources of network operators are now channelled into the implementation of Redispatch 2.0. In the interviewee's view, the development of local flexibility markets in a hybrid scheme could be a next step when Redispatch 2.0 is fully implemented and consolidated.

During the interview with the representative of EPEX SPOT, the following notable points were made.

- EPEX SPOT expects a variety of services, beyond congestion management, to be procured through local flexibility markets by DSOs in the future, with the first being voltage control / reactive power services. Nevertheless, local flexibility markets for congestion management should be consolidated first.
- Both long-term/availability and short-term/activation products will probably be requested in future flexibility markets, subject to the specific network needs in each case. Long-term contracts are aimed more at network deferral, while short-term activation products are aimed at congestion management.
- Even though current short-term local flexibility markets follow the continuous pay-as-bid paradigm, the interviewee held the opinion that auction-type pay-as-clear markets may be a valid alternative for the following reasons: (1) better price formation, (2) better coordination between the different network operators towards co-optimisation of the procurement process and (3) easier market monitoring. Given that flexibility is not continuously needed by network operators, auctions would take place only when the need would arise. In critical cases, a further possibility could be cascading auctions during the day. (It is noted here that the Platone Horizon 2020 project ([75]) also investigates an auction-type short-term local flexibility market architecture.)
- The current architecture of different markets for flexibility services (e.g. for congestion management in the distribution system as opposed to system balancing) will continue for the foreseeable future. Nevertheless, better coupling/coordination between them should start to be addressed.
- On baseline methods, both centrally defined baselines by the market operator and/or the buying network operators and FSP schedules are valid approaches, depending on the specific technological characteristics of the underlying flexibility assets.
- Penalties for partial delivery of flexibility may be needed in the future for fostering FSP responsibility.
- Contractual relationships between independent aggregators and BRPs is a difficult issue to address. A way forward may lie in bilateral agreements with a back-up regulatory framework playing the role of a safety net.
- Regarding the governance framework of future local flexibility markets, the interviewee held the view that both market platforms operated by independent market operators and marketplaces run by network operators will be developed in Europe. In the latter case, power exchanges such as EPEX SPOT would play the role of service provider for the development of the market platforms.
- In the case of local flexibility markets run by independent operators, these could undertake legal compliance of market parties and financial risk management. Technical pre-qualification procedures should always remain under the buying network operators' responsibility.
- According to the interviewee's personal view, the main reason for the decision of the German regulator to opt for the continuation of rule-based redispatching was the fear of inc-dec gaming. However, this decision comes at the expense of reduced liquidity for congestion management services, as demand is left out and there is a lack of incentives for incorporating flexibility as an alternative in long-term network development. Furthermore, flexibility markets may be easier to implement technically. Overall, the interviewee expressed the opinion that a hybrid model in which rule-based and market-driven flexibility provisions coexist, as proposed by the enera project promoters, may become the way forward at some point in the future in Germany.

([75]) https://www.platone-h2020.eu/

— Inc-dec gaming should be not considered a showstopper for the development of local flexibility markets, but instead should be considered an issue of regulatory supervision and market surveillance, for which methods can be developed (with statistical analysis being one of them).

— Effective national implementation of the recast electricity regulation and electricity market directive will be catalytic for the development of local flexibility markets in the EU.

— Finally, it is noted that EPEX SPOT is planning to connect with GOPACS in the Netherlands, and it recently invested in increasing its own technical capabilities for developing local flexibility market platforms ([76]). Baseline provision and verification of flexibility activation are among the services intended to be provided. Nevertheless, for the latter, network operator validation will always be crucial.

4.7. UK flexibility tenders

4.7.1. General information

— Initiation year: 2018

— Status: ongoing

— Country: United Kingdom

— Network operators involved: all UK DSOs

— Web page: https://www.energynetworks.org/creating-tomorrows-networks/open-networks/flexibility-services

In December 2018, the first tenders for the provision of flexibility services to certain UK DNOs took place, with the intention for this to become a business-as-usual activity. Separate tenders are called from each DNO, but a structured harmonisation effort regarding the whole process of local flexibility procurement (standardisation of contracts, product specification, baseline methodology, cost–benefit analysis against classic network expansion, etc.) is undertaken in the context of the open networks programme of the ENA ([77]). The tenders are aimed at network deferral, congestion management, reliability enhancement and support for network re-energisation, and they led to long-term contracts between DNOs and FSPs.

An increasing volume of flexibility has been procured each year, reaching 2.9 GW in 2021 (ENA, 2022a). There are two main platforms through which FSPs can participate in the tenders: Piclo Flex ([78]), which is an independent trading platform used by Electricity North West, NIE Networks, SP Energy Networks and UK Power Networks in 2021, and Flexible Power ([79]), which is a joint initiative by Western Power Distribution, Northern Powergrid, Scottish and Southern Electricity Networks, SP Energy Networks and Electricity North West. It is noted that, alongside flexibility tenders, DNOs in the United Kingdom also employ flexible connections as a flexibility instrument.

4.7.2. Pre-qualification procedures

The procurement platform first performs an automatic pre-qualification for every flexibility asset (location, voltage level, etc.) and then the DSOs perform a deeper screening based on pre-qualification questionnaires. The latter are currently being digitalised in Piclo Flex (Anagnostopoulos, 2022). These questionnaires include questions on the assets' technical characteristics (location, voltage, minimum capacity, run-up and ramp-up times, communication system, metering, and compliance with applicable network code requirements) and flexibility providers' commercial assessment (corporate regulatory obligations, legal offences, creditworthiness, conflicts of interest, etc.). The assessment is conducted through dynamic purchasing systems, which either belong to the DSO or are provided as a service by the market platform (ENA, 2020a; Anagnostopoulos, 2022).

The information gathered in the pre-qualification questionnaires forms the basis of a register similar to the FDR. In principle, all types of assets are accepted, in every phase of development (i.e. from projects in the planning stage to fully operational assets). The minimum required flexible provision capability of a flexibility

([76]) https://www.epexspot.com/en/news/new-trading-platform-boosts-epex-spots-localflex-offer
([77]) https://www.energynetworks.org/creating-tomorrows-networks/open-networks/
([78]) https://picloflex.com/
([79]) https://www.flexiblepower.co.uk/

asset varies between DNOs from 10 kW to 50 kW. The qualification period by the network operator is usually 2 weeks (Aithal, 2021; Anagnostopoulos, 2021a). Asset testing is conducted after a contract is signed between a DSO and an FSP (i.e. after a winning offer by the latter in a flexibility tender) to verify the capability of the assets to provide the flexibility product.

4.7.3. Flexibility products

Currently, there are four active power services, defined as follows (ENA, 2020b; Flexible Power, 2022).

1. **Sustain.** The network operator procures, ahead of time, a pre-agreed change in input or output over a defined period to prevent a network going beyond its firm capacity. The requirement windows for provision of the service are scheduled and fixed in the contract. This product aims at investment deferral.
2. **Secure.** The network operator procures, ahead of time, the ability to access a pre-agreed change in service provider input or output based on network conditions close to real time. Secure requirements are declared 1 week ahead. Payments consist of a fee that is credited when the service is scheduled and a further utilisation payment awarded on delivery. This product aims at congestion management.
3. **Dynamic.** The network operator procures, ahead of time, the ability of a service provider to deliver an agreed change in output following a network abnormality (including scheduled maintenance). Remuneration consists of an availability and a utilisation component. FSPs are expected to be ready to respond to utilisation calls within 15 minutes. Dynamic availability windows are declared 1 week ahead. This product aims at enhancing network reliability.
4. **Restore.** Following a loss of supply, the network operator instructs a provider to remain off supply, reconnect with lower demand, or reconnect and supply generation to support increased and faster load restoration under depleted network conditions. As the requirement is inherently unpredictable, this product is based solely on a premium 'utilisation only' compensation component. FSPs that are declared to be available for this service are expected to respond to any utilisation call within 15 minutes. This product aims at supporting re-energisation of the network.

A description of the parameters of each service is provided in Table 8 and Table 9. The divisibility of bids depends on the DNO and the product.

For the abovementioned services, work is ongoing to standardise the parameters. Currently, six flexibility product parameters for convergence and implementation have been proposed.

1. Minimum flexible capacity. This is the minimum flexible capacity an FSP may make available to the DNO. This can be made up of aggregated or non-aggregated DERs.
2. Minimum utilisation. This is the minimum amount of time a DNO will require for the provision of a flexibility service from an FSP, following a utilisation instruction.
3. Minimum utilisation duration capability. This is the minimum amount of time that an FSP must be able to continually hold its contracted flexible capacity, in minutes.
4. Maximum ramping period. This is the maximum allowed time, once a utilisation instruction has been issued or becomes active, for an FSP to reach its contracted flexible capacity.
5. Availability agreement period. This is the time period before a flexibility service is required by a DNO, in which the DNO and the FSP may agree the FSP's availability window.
6. Utilisation instruction notification period. This is the time period before a flexibility service is required by a DNO, in which a DNO may issue a utilisation instruction to an FSP.

Other parameters that may be specified are the service recovery time and the maximum utilisations per service window. The products generally have an availability and a utilisation compensation component, but the specifics are defined in each tender. When they have both, FSPs must specify in their offers the price of both components.

Moreover, there have been some pilot projects on the procurement of reactive power flexibility services by DNOs. In 2022, there will be a decision on whether these will also enter a business-as-usual status (Aithal, 2021).

Table 8: Summary of the active power services in the United Kingdom

Service Parameter	DNO Flexibility Products				
	Sustain	Secure (Scheduled)	Secure (Dispatched)	Dynamic	Restore
When required?	Scheduled forecast overload	Pre- fault / peak shaving		Network abnormality / planned outage	Network Abnormality
Risk to Network	Low	Medium		High	High
Utilisation Certainty	High	High		Low	Low
Frequency of Use*	High	Medium		Low	Low
Minimum Flexible Capacity	0-50kW				
Minimum Utilisation Duration Capability	30 mins				
Minimum Utilisation	15 - 30 mins				
Maximum Ramping Period	N/A	N/A	<15 mins	<15 mins	<15 mins
Availability Agreement Period	N/A	Contract stage	Week ahead	Contract stage if appliccable	Contract stage if appliccable
Utilisation Instruction Notification Period	Scheduled in advance**	Contract stage	Real Time	Real Time	Real Time

* Frequency is location specific defined at the point of procurement

** Utilisation requirements may differ to schedule and be instructed in real time

Source: (ENA, 2020b).

Table 9: Specifics of the flexibility products

Category	Product	Metering Resolution	Type of remuneration	Earliest utilisation instruction notification	Latest utilisation instruction notification	Typical utilisation period	Frequency of use
A	Sustain	HH metering	Utilisation and Availability	Scheduled in advance Years ahead	3 months ahead	Not defined, typically 3 to 24 hours	High: 5 deployments per week
A	Secure Scheduled	metering requirements vary across DNOs		Contract stage	3 months ahead	not defined, typically 3 hours or more	Medium: 2 deployments per week
B	Secure Dispatched			10 days ahead	3 days ahead		
C	Secure Dispatched			30 minutes	Real Time		
D	Dynamic			15 minutes	Real time	Not defined, Typically several hours (it could take up to days)	Rarely, in case of faults
D	Restore		Utilisation (it can also be availability only, it depends on DNOs)	15 minutes	Real Time	Not defined, Several hours to days, minimum 3 hours	Rarely, in case of complete loss of supply

Source: (ENA, 2020c).

4.7.4. Flexibility procurement process

The tenders aim for long-term contracts that could reach up to 7 years ahead. They are organised by each DSO per congestion zone. The voltage level in the congestion zones ranges from 11 kV to 132 kV, with the majority of being at 33 kV (Aithal, 2021).

There are two procurement cycles per year for each DSO. Before a tender is called, DSOs usually publish information highlighting indicative areas in which flexibility needs could arise in the near future (signposting). When the tender is called, a DSO initiates a competition, asking for a specific flexibility product in a specific congestion area and a specific service delivery period. The timing of the process is shown in Figure 5. The awarding of contracts usually takes 2–3 weeks from the bidding window closure.

The DSO decides on the winning bids based on price (70 % weight) and technical characteristics above the minimum requirements (30 % weight), which include (ENA, 2020a):

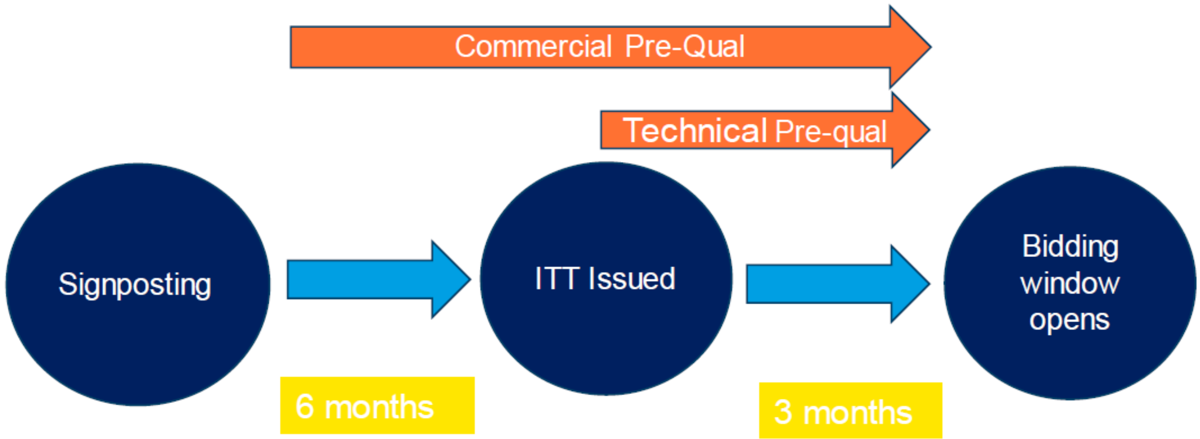
- an assessment showing that flexibility provision will not cause operational security violations in other parts of the network;
- conflicts with other provided services;
- effectiveness;
- ramp rates (above flexibility product minimum requirements);
- energised status of assets;
- type of connection (flexible versus firm);
- type of metering.

The exact evaluation formula per tender is included in the call documentation. Further refinement of the bid evaluation process is under way.

Price caps are defined by network operators, which are published before the submission of offers by FSPs. Price caps correspond to the annualised cost of the alternative classic network investment, which is defined by a common evaluation methodology (ENA, 2021a).

Accepted offers are communicated by DSOs to the procurement platform and from there to the flexibility provider. A contractual agreement is then needed between the DSO and the FSP, which has been harmonised (ENA, 2021b). The pricing mechanism is pay-as-bid for both availability and activation components.

Figure 5: Aligned procurement timescales in UK flexibility tenders



ITT: Invitation to Tender

Source: (ENA, 2020a).

4.7.4.1. *Coordination between network operators*

Each DSO launches its own tenders for specific parts of its network. Currently, the procurement of local flexibility services and the procurement of system ancillary services by the TSO are very loosely coordinated, with each network operator having separate procurement methods.

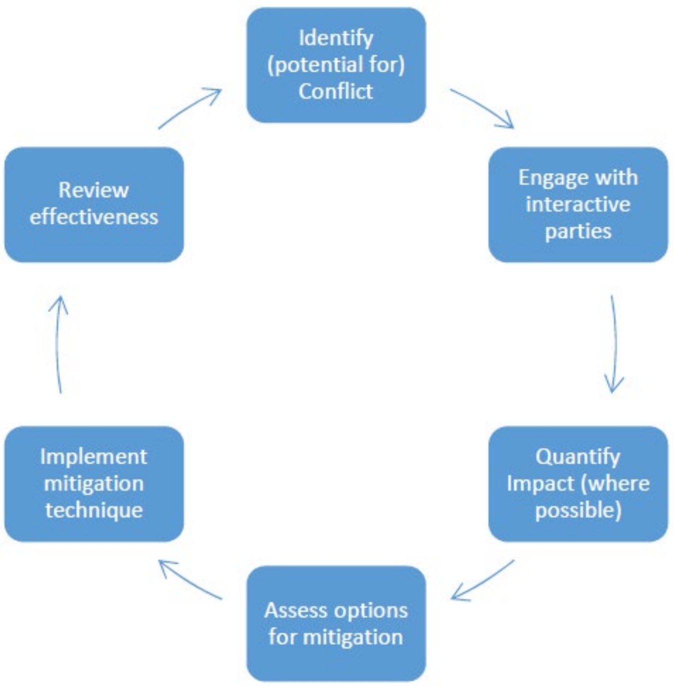
Conflicts arising from flexibility activation between different network operators have not been identified so far. According to the experience to date, the activation of flexibility does not cause noticeable imbalances, as these are lost in the 'noise' of demand and generation variability, but this could change in the future. This is also one reason why the contractual relationships between independent FSPs and suppliers/BRPs have not been analysed in detail yet in the open networks programme.

Nevertheless, the open networks programme has set out some generic guidelines for conflicts resolution in the activation of flexibility services, which are based on enhancing network observability, data exchange and consultation between interested parties (

Figure 6) (ENA, 2020d). A general principle suggested is that mitigation actions should primarily be the responsibility of the procurer of flexibility services. FSPs also take on a significant part of the responsibility by securing that they can honour at any time their contractual obligations to both DSOs and the TSO. Furthermore, mapping of potential conflicts between the TSO and DSOs' flexibility services was developed in 2021 (ENA, 2021c).

Regarding co-optimisation in the procurement of flexibility services by different network operators, this has been identified as a priority for the future, but no particular steps have been taken so far. One of the main reasons for this is that the TSO has moved to day-ahead and shorter time procurement windows for many ancillary services; therefore, of more importance is the development of local flexibility markets closer to real time. In addition, a greater level of harmonisation of pre-qualification procedures between the TSO and DSOs was identified as a priority (ENA, 2021d).

Figure 6: Proposed conflict management cycle in the open networks programme



Source: (ENA, 2020e).

4.7.5. Activation and settlement procedures

FSPs activate flexibility after communication by the DSO, with the aim being full automation of the process, mainly employing APIs (ENA, 2020f; Aithal, 2021).

For the settlements of the FSPs, a baseline is employed. A baseline tool is currently being finalised (ENA, 2022b). It is based on the UK DNOs' core baseline principles for measuring the delivery of flexibility services, which are simplicity, accuracy, integrity and replicability (ENA, 2020c). Three types of baseline methodologies have been chosen:

1. a historical baseline (or rolling baseline), which is intended for all products, noting that, for the 'sustain' product, it should be applied only to flexible demand;
2. a historical baseline with same-day adjustments, which has the same applicability as a simple historical baseline and is preferred when the utilisation instruction period is closer to real time (from a week ahead and closer);
3. FSP nominations, which are applicable to all products except 'sustain', for which historical baselines are low and historical data are not available; FSP nominations are considered most suitable when submeter readings are available.

When there are no historical data available, there is a problem for baseline implementation for the 'sustain' and, at times, the 'secure scheduled' products, for which it was recommended that technology-specific validation mechanisms be tested and more experience be accumulated. The reason for this is that long utilisation instruction notification periods and long utilisation periods allow limited options for these products (ENA, 2021e).

The settlement period is 30 minutes. When measurements with finer granularity are available, these are averaged in this time window (i.e. the settlement is made on energy, not power, terms).

Remuneration of the availability component of successful offers is made after the activation period, depending on successful activation of the flexibility service. Currently, no penalties apply, but there is a reduction in remuneration in the case of partially delivered flexibility. Given the state of development of local flexibility services, this is more of a practical choice than a theorised rule, so it may change in the future.

Independent aggregators are permitted in most UK electricity markets, including the TSO ancillary services market and the capacity mechanism. There is not a strict formalised framework for the contractual relationships between independent aggregators and suppliers, but an accreditation system (Flex Assure ([80])) is highly promoted by the overall market (Aithal, 2021).

4.7.6. Results, lessons learnt and future developments

Flexibility tenders by UK DNOs have reached a business-as-usual status. An increasing volume of flexibility is being procured, reaching 2.9 GW in 2021 from 1.1 GW in 2020. Most flexibility comes from the commercial and industrial sectors, while participation from the residential sector is still low (Aithal, 2021).

Regarding the overarching work made by the ENA on flexibility, notable developments include a methodology and tool to compare flexibility deployment against classic network expansion (ENA, 2021a), the alignment of procurement procedures among the UK DNOs, further improvements to the common baseline methodology and the assessment of potential conflict areas between DNOs' and the TSO's flexibility services. Future work will continue on all of these subjects and on interoperability across DNO and TSO systems, reviewing it further and possibly adding new flexibility products, addressing barriers for FSP value stacking, improving the provision and accessibility of curtailment information for flexible connections, and the development of common methodologies for carbon reporting and monitoring across DNOs, along with Ofgem and the Department for Business, Energy & Industrial Strategy. The timeline for the flexibility tenders at both distribution and system level for 2022 has already been published.

Two interviews were conducted on the UK tenders, one with a representative of Piclo Flex and another from the open networks programme (Anagnostopoulos, 2021b; Aithal, 2021). Notable points included the following.

— While the United Kingdom represents the largest market for local flexibility services in Europe, and with more than 100 % growth between 2020 and 2021, liquidity still is relatively low with respect to the requirements, with almost 50 % of the tendered volume not being covered.

— Long-term tenders were chosen as the preferred procurement architecture by DNOs for getting experience in a secure and controlled way. While they will probably remain for the foreseeable future, both interviewees had the opinion that the general direction will be towards closer to real-time flexibility

([80]) https://www.flexassure.org/

markets. It is noted that the same view was shared by the interviewee from Western Power Distribution on the IntraFlex project.

- Independent aggregators represent a significant percentage of participating FSPs.
- The end-goal is coordinated flexibility procurement by network operators (DSOs and the TSO), but this is going to be a lengthy process. More specific guidelines for conflict resolution are going to be developed in 2022. It is noted that this end goal may not necessarily mean a single flexibility market, but more than one 'flexibility exchange', which operate in a coordinated way, similar to the situation in the wholesale energy market, where there may be more than one power exchange in the same country (this is also the case in the United Kingdom).
- A series of other services may be required by DNOs in the future, including inertia for local grid stability, short-circuit current injection, black-start and island operation capability. These are in the context of the transformation of UK DNOs to system operators of active distribution networks. Many of the required flexibility services, if not all, are going to be procured through market-based mechanisms. An imminent decision in 2022 is expected on whether the pilot projects on procurement of reactive power/voltage control flexibility services will upgrade to business as usual.
- Communication protocols are still unharmonised between network operators. Future effort on harmonising the functional specifications is already planned.
- The national regulatory authority, Ofgem, follows the open networks programme very closely and has set up a 'flexibility first' approach on network development and operation, strongly incentivising the procurement of flexibility services by DSOs.
- Besides the procurement process, Piclo Flex can optionally manage the operations (availability, dispatch) and settlement (performance, invoicing) procedures. In addition, Piclo Flex is developing more capabilities of a fully-fledged flexibility marketplace, such as facilitation of short-term competition, while it is supporting the development of a common European framework for flexibility markets based on open APIs.

4.8. ENEDIS flexibility tenders

4.8.1. General information

- Date of initiation: June 2020
- Status: ongoing
- Country: France
- Network operators involved: ENEDIS (DSO)
- Website: https://flexibilites-enedis.fr/

In June 2020, ENEDIS, the main French DSO, launched its first flexibility tender. Tenders have been launched as a business-as-usual case every year since 2020 (so far three tenders), amounting to 19 opportunities for upwards flexibility services to date. ENEDIS is now encompassing downwards flexibility to solve injection congestion issues (ReFlex project) and has published nine opportunities, which must now be detailed and scheduled, consistently with new DER connection applications and their congestion creation.

It is noted that all calls, except one in which two bids have been submitted, ended null, as no offers were submitted (ENEDIS, 2020b; ENEDIS, 2021).

4.8.2. Pre-qualification procedures

For each flexibility tender, FSPs can assess their eligibility through the Enedis website ([81]), checking their delivery or measurement points (respectively in French 'Point de Livraison (PDL)' and 'Point de Référence Mesure (PRM)'). The module allows market players to test either a single metering identification or an imported metering identification list. Results are immediate and can be exported (in the case of mass import). It is noted that not all connection points inside a congestion zone are eligible for participation, as they may not be able to offer the requested services due to the specifics of their electrical topology (Kuhn, 2021).

([81]) https://flexibilites-enedis.fr/

When offers are submitted, FSPs must provide a detailed list of their portfolio's flexibility assets per network connection point and the technical characteristics. Technical characteristics – such as flexible capacity compared with respective connection agreements and confirmation of location – are screened out by ENEDIS. If portfolios include non-eligible sites, ENEDIS either disqualifies the offer or asks for a resubmission. There are no minimum capacity limits for the participation of flexibility assets.

Assets participating in other electricity markets through a different legal representative cannot be declared by the FSP under the penalty of rejection of the offer. Independent aggregators must have an agreement with the respective BRPs for participating in the flexibility tenders.

Upon acceptance of an offer, two pre-qualification tests are undertaken: a test of communication between ENEDIS and the FSP (non-compensated) and a test of flexibility activation (compensated).

4.8.3. Flexibility products

Depending on the case, the tenders aim at different flexibility services, such as investment deferral, short-term congestion management and enhancement of reliability (e.g. the activation of flexibility in cases of planned maintenance or after an outage in the network). Tenders are organised per congestion area, called 'opportunity zones'.

Product specifications include:

- eligibility zone,
- capacity per predefined period,
- full activation time,
- activation duration,
- neutralisation duration between activation (in hours),
- maximum injection ramp,
- notification period.

ENEDIS also provides an estimation of activated flexibility that will be needed in MWh/annum and the maximum activation period.

In general, flexibility products have both an availability and an activation component. While product specification characteristics are standardised, as mentioned above, the specific parameters change per call and respective opportunity zone. Furthermore, in each call, a number of specific product options are requested in terms of the aforementioned technical characteristics, with a different evaluation score for each one known beforehand to potential participants. These specific product options are not divisible. Their minimum size is 500 kW and their minimum activation period is 30 minutes (Kuhn, 2021).

The main reason behind the specific product specification is the methodological approach taken by ENEDIS regarding the cost–benefit analysis for employing flexibility, which, according to detailed feedback from the interviewees, is summarised as follows. As per Article 32.1 of the clean energy package, flexibility must improve the cost-effectiveness of network design or operations; therefore, flexibility competes against the best alternative in terms of network investment, which ends up in requiring quite specific products for flexibility to reach sufficient effectiveness. So far, for the sake of simplicity, a single winner for availability contracts (i.e. a single contract) is considered by ENEDIS, while, for activation, ENEDIS will chose the best available flexibility (Kuhn and Dupin, 2021). A detailed presentation of the methodology employed by ENEDIS for the valorisation of flexibility can be found in (ENEDIS, 2017).

4.8.4. Procurement of flexibility

Long-term tenders are organised per zone. The procurement horizon varies from 5 to 44 months ahead of flexibility delivery. Overall, tenders have been issued for 19 opportunities in 14 zones. The maximum voltage in each zone has been 20 kV (the maximum voltage level in the ENEDIS network). Tenders have been issued in 2020, 2021 and 2022.

Procurement is made for a whole future year and flexibility is required for certain predefined periods of the year (e.g. for December to March every day between 18.00 and 21.00 and between 22.00 and 24.00).

For energy products, the evaluation of offers is made solely based on price. For availability products, the evaluation of offers depends on the purpose of the flexibility service. In most cases, when the service is the alleviation of power congestions, the evaluation of offers is made solely based on price. However, when voltage-related security constraints limit the effectiveness of flexibility sources, sensitivity factors per flexibility asset connection point are employed in the selection of offers. The scoring criteria are disclosed beforehand in the tendering materials.

Price caps, also called the propensity to pay, are imposed in the selection of offers, but these are not published beforehand. They correspond to the difference between the effectiveness of flexibility (the reduction of lost loads, valued as value of lost load (VOLL)) and the effectiveness of classic investment (the annualised cost of the best alternative network expansion plus its effectiveness on VOLL and losses). The pricing mechanism is pay-as-bid for both availability and activation components.

According to the survey results, ENEDIS and the TSO do not expect particular operational security issues in the upstream network resulting from flexibility activations for the time being, owing to the relatively low volume in this early phase of development of local flexibilities and the joint willingness to start local flexibilities. For the same reason, for the time being, they do not expect noticeable system imbalances to be caused.

4.8.5. Activation and settlement procedures

The activation of a flexibility service is done via phone call or email by ENEDIS to the FSP. ENEDIS is working on implementing API activation in the near future (Kuhn, 2021). In general, there is no pre-announcement for activation of a contract (i.e. the product notification period is followed). If the flexibility product aims at reliability enhancement (e.g. for outage management), the notification period can be as low as 0 minutes for delivery 30 minutes later (Kuhn, 2021).

The measurement and settlement period is 30 minutes. A baseline is employed for the settlement. Eight different baseline methods are proposed by ENEDIS, depending on the type of flexibility facility (demand response, production units or mixed) and their size, to be chosen by the FSP, including the declaration of schedules by the latter. More specifically, five baseline methods are proposed for demand-response facilities, three are proposed for production facilities and two are proposed for mixed facilities. The FSP can define a different baseline methodology for each type of facility (demand response, production or mixed) in its portfolio. If a facility also provides flexibility services to the TSO, then the same baseline methodology has to be employed for the two cases (flexibility provision to the TSO and flexibility provision to the DSO). In addition, ENEDIS certifies beforehand and throughout the whole life of the contract the quality of the schedules provided by FSPs if they have chosen this option. If they do not meet ENEDIS standards, schedules are rejected and a default method is used (Kuhn, 2021).

Remuneration is made on a monthly basis, for both the availability and the activation components. Remuneration of availability components is made after the activation period and subject to successful delivery. Reduced remuneration plus penalties apply when flexibility is partially delivered, resulting, in extreme cases, in the FSPs paying the buying network operator. There is no additional compensation for over-delivery (Kuhn, 2021).

Flexibility activations are considered as instructed imbalances in the calculation of the BRPs' final position. This effectively results in the FSPs undertaking balance responsibility for their cleared offers.

In addition, FSPs have to compensate BRPs for the energy pre-bought by the latter in the wholesale market and offered by the former as flexibility. This will be done in the French DSO market starting in March 2023: it will be covered by the contract and will rely on existing TSO rules (e.g. for the block exchange notification of demand response (NEBEF) mechanism ([82])) to define the compensation prices. The compensation will be a function of the activated volume and will be dispatched among the affected BRPs (Kuhn, 2021).

4.8.6. Results, lessons learnt and future developments

All calls, except the one for which two bids were submitted, ended null, as no offers were submitted. For 2021, this led to the calls being extended until the end of the year, although with no better results. According to the survey and the structured interviews, reasons for the low liquidity in the flexibility marketplace included the following.

([82]) More information on the NEBEF mechanism is available on the RTE (the French TSO) website (https://www.services-rte.com/en/learn-more-about-our-services/nebef-compensation-payment.html).

— This is an emerging market compared with the well-known TSO markets, which already offer significant value to FSPs (e.g. the capacity remuneration mechanism).

— There is low availability of flexibility assets and relatively high capacity needs for the narrow congestion zones. On average across the ENEDIS network, there has been, to date, only one LV flexible site per MV feeder and less than one MV flexible site per HV/MV primary substation already active on national mechanisms. Therefore, aggregators have to target a local zone and recruit enough flexible sites to respond to ENEDIS tenders.

Other notable points made by the interviewees include the following.

— For the time being, of major interest is downwards flexibility. In general, owing to the strength of the distribution network in France, uncapping the flexibility potential for upwards flexibility is not very urgent from the DSO perspective.

— ENEDIS currently assesses the opportunity of implementing a market platform enabling continuous trading. In this case, the envisaged gate closure time will be 2 hours before activation.

— Regarding network operators' coordination, ENEDIS works with RTE (the French TSO) to share the flexibility offers between system operators (common offers and shared visibility). It is a work in progress and it should lead to a close coordination process once implemented. This is important to ENEDIS, given that, currently, TSO markets (including the capacity remuneration mechanism) are much more attractive to FSPs.

— ENEDIS considers that a lower level network operator should have precedence in the procurement of flexibility from assets in the distribution system.

5. Synthesis of reviewed local flexibility markets

This chapter provides a consolidated view of the local flexibility markets examined based on the dimensions of analysis followed in this work (pre-qualification procedures, flexibility product specification, market architecture, and activation and settlement procedures). The similarities and differences are discussed. Finally, major issues defining the evolution of local flexibility markets in Europe are identified, based on both a desktop analysis and the interviews carried out.

5.1. Pre-qualification procedures

Table 10 provides a consolidated view of the pre-qualification procedures of the local flexibility markets reviewed.

All of the marketplaces examined follow the concept of conditional (as opposed to dynamic) pre-qualification procedures ([83]).

The depth of pre-qualification procedures depends on the features of the local flexibility market, that is, on its pilot project or business-as-usual nature. Pre-qualification procedures are rather light for the former, with the main prerequisites being that flexibility assets are placed inside the required congestion zone, as well as successful communication with the market platform and/or the FDR and agreement with the market operator's rulebook. More mature flexibility markets such as those in the United Kingdom also encompass financial risk analysis and compliance with relevant legal provisions through dynamic purchasing systems.

Asset declaration to a digital register (the market platform and/or the FDR) and a first automatic pre-qualification stage regarding correct location can be considered good practice. Moreover, the general direction is towards network operators accumulating detailed technical data of all participating flexibility assets (i.e. towards the FDR concept). Importantly, the buying network operators are currently responsible for all matters of pre-qualification, with market platforms playing only a facilitating role (asset registration and verification of locational eligibility).

Flexibility assets' minimum required capacity limits vary significantly in size but also in definition: in certain markets, compliance is defined on a flexibility portfolio basis (e.g. sthlmflex), while, in others, it is defined on a flexibility asset basis – especially those in which the FDR is central in the overall market architecture (e.g. NorFlex). On the upside, the analysis did not show any indication of exclusion of flexibility assets on the grounds of their technology, even though, in some cases, technology-specific weights are imposed in the evaluation of flexibility bids (e.g. in the UK tenders).

Physical technical tests are, in most cases, either non-existent or minimal (e.g. an end-to-end system test for one asset). However, it is noted that network operators are increasingly setting up verification processes of the flexibility assets' technical capabilities as part of the settlement procedures.

An emerging serious issue is the different pre-qualification processes and minimum requirements for participation in local flexibility markets, on the one hand, and in TSO ancillary services markets, on the other. This could induce additional costs for FSPs. Ideally, a single pre-qualification process should be established enabling participation in all markets, as a means, among other things, to foster value stacking. Implementation of the FDR concept could facilitate this (see also CEDEC et al., 2021).

Finally, the following issues may be critical in facilitating, or instead pose barriers to, the uptake of local flexibility markets regarding technical and/or regulatory requirements.

- Data ownership and compliance with relevant legal provisions, especially when submeter measurements are employed for settlement purposes.
- The definition of SGUs and whether flexibility assets (either individually or in an aggregated pool) fall into this category. This will define whether real-time measurement exchanges to network operators will become a regulatory obligation (CEDEC et al., 2021).
- Information and telecommunication technology interoperability requirements. If harmonisation with a single protocol such as CIM is imposed quickly, this may lead to a significant cost barrier, especially for small FSPs. While harmonisation may prove necessary in the long run (especially towards an integrated TSO/DSO market), an easier way forward may now be represented by the employment of APIs, although this might also prove challenging at times, as shown in the NorFlex project.

([83]) For the difference between the two see CEDEC et al., 2019.

— The regulatory framework for the contractual relationships between independent aggregators and BRPs. Very strict requirements, especially the necessity for BRP approval, may pose barriers to unlocking the flexibility potential in the distribution system.

Table 10: Consolidated view of pre-qualification processes among the flexibility markets reviewed

Process	**sthlmflex**	**IntraFlex**	**NorFlex**	**GOPACS**	**enera**	**UK tenders**	**ENEDIS tenders**
Asset declaration	Market platform	Market platform	FDR	IDCONS participation agreement	FDR	Procurement platform and pre-qualification questionnaires	In flexibility offer
Technical assessment	— Metering points — FSP baseline methodology — Minimum bid size of 0.1 MW — Test trade — Activation test (seasonal contracts only) — TSO compliance (for participation in the mFRR market only)	— Metering points — Test trade — End-to-end system test for one asset per FSP	— Metering points — Successful communication with market platform and FDR — Minimum nominal capacity of 1 kW	— Metering points — As per wholesale market rules	Metering points	— Metering points — Technical characteristics — Network code compliance — Minimum flexible capability (10–50 kW, depending on DSO) — Activation test	— Metering points — Technical characteristics — Successful communication with network operator — Activation test
Regulatory assessment	— Power of attorney agreement — Agreement with market operator's rulebook — Contract with BRPs (for participation in the mFRR market only)	— Agreement with market operator's rulebook — FSP legal trustworthiness check by network operator	Agreement with market operator's rulebook	— Participation in a connected market platform — IDCONS participation agreement	Very light/none	FSP legal trustworthiness check by network operator	— Same legal representative for all markets — Contractual agreement with BRPs for independent aggregators
Duration of pre-qualification process	14 days	14 days	0 days	5 working days	0 days	14 days	During offer assessment

Source: JRC analysis.

5.2. Flexibility product design

Table 11 provides a consolidated view of the design of the flexibility products of the local flexibility markets reviewed.

All of the marketplaces reviewed focus on congestion management flexibility services, with network deferral the second most common focus and enhancement of network reliability (e.g. the activation of flexibility during planned maintenance or forced outages) the third most common. The intended service defines to a great extent the design of traded flexibility products. In most cases, short-term trading (i.e. 1 week ahead and closer to real time) is employed for congestion management, while longer term contracts (months to years ahead) are used for network deferral and reliability enhancement services. Only the two Nordic markets reviewed in this work pass (aggregated) bids into the TSO balancing market.

Short-term products have only an activation component and are divisible. *Ex ante* explicit price caps do not exist as such, but buying DSOs either actively submit bids (IntraFlex and, NorFlex) or compare offers to best alternatives (e.g. subscription swap in sthlmflex or RES curtailment cost in enera). While, in most cases, these are defined in energy terms, two marketplaces (NorFlex and IntraFlex) required flexibility provision in power terms. For this, high temporal granularity of measurements was required, along with much finer flexibility control by FSPs, given that settlement in this case is conducted on a 1-minute basis. It may be noted that certain interviewees questioned the need for such fine resolution for congestion management, even though it was acknowledged for voltage control services (see the feedback from the sthlmflex market in Section 4.2.6). While, in most cases, flexibility offers are simple orders, IntraFlex permitted more sophisticated options such as fill-or-kill and minimum quantity. Overall, flexibility products for short-term congestion management are fairly similar to their respective products in wholesale markets (day ahead, intraday and balancing), with the main difference being the minimum acceptable volume, with local flexibility markets permitting smaller volumes and locational information.

The time horizon of longer term contracts varies widely between the marketplaces reviewed, ranging from weeks to years ahead. Generally, they have an availability and an activation component. In all cases, FSPs bid freely for seasonal and years-ahead contracts, but, for the weekly contracts employed in the two Nordic local flexibility markets reviewed, network operators predetermine the price for either the availability compensation or both. It is debatable whether this is a structural decision, as these two pilot projects focus, among other things, on product experimentation, and weekly contracts were also introduced for fostering market liquidity.

Overall, availability products in the local flexibility markets reviewed diverge significantly from TSO balancing capacity products in some fundamental characteristics as defined in EU law: Article 6 of the electricity regulation states that balancing energy prices shall not be predetermined in contracts for balancing capacity (i.e. bids for availability and activation components should be disentangled), and that balancing capacity should be procured in the day-ahead time frame as the default option. This significant divergence could be a root cause for future difficulties in integrating DSO and TSO flexibility markets, even though the underdeveloped market structure for transmission system congestion management services will be on this fundamental. On the other hand, it is indeed difficult to fathom how DSOs could procure network deferral and extent reliability enhancement flexibility services based solely on short-term markets, similar to the provisions of the electricity regulation for balancing capacity products, given the current state of maturity and the liquidity of distributed flexibility. Especially for network deferral, for which long-term contracts seem more suitable, one could argue that the appropriate analogy to system services products would be capacity mechanisms.

Referring to the terminology used in CEDEC et al. (2021), long-term contracts employed in the local flexibility markets reviewed share the following attributes:

- locational information
- the duration of the contract
- the availability window
- the validity period
- the direction of activation
- the maximum quantity
- the activation period.

Buying network operators in most of the markets reviewed also try to define an indicative maximum number of activations (frequency).

Table 11: Consolidated view of flexibility products among the flexibility markets reviewed

	sthlmflex	IntraFlex	NorFlex	GOPACS	enera	UK tenders	ENEDIS tenders
Targeted flexibility services							
Network deferral	X	—	X	-	-	X	X
Congestion management	X	X	X	X	X	X	X
Reliability enhancement	X	—	—	—	—	X	X
Network re-energisation		—	—	—	—	X	—
System balancing	X	—	X	—	—		—
Direction of flexibility	Upwards	Mainly upwards	Upwards and downwards	Upwards and downwards	Downwards	Mainly upwards	Upwards and downwards
Type of products							
Long-term contracts	Seasonal	—	—	—	—	Years ahead	Years ahead
Availability component	FSP bids	—	—	—	—	FSP bids	FSP bids
Activation component	FSP bids	—	—	—	—	FSP bids	FSP bids
Weekly contracts	Called on an ad hoc basis	—	Procured on a monthly basis	—	—	—	—
Availability component	Network operator defined	—	Network operator defined	—	—	—	—
Activation component	FSP bids	—	Network operator defined	—	—	—	—
Short-term trading	X	X	X	X	X	—	—
Bids specification							
Minimum bid size	0.100 MW	0.001 MW	0.001 MW	As per Intraday Market	As per Intraday Market	0.010–0.050 MW	Product dependent
Divisibility	X	X	X	X	X	Depends on DNO	No
Other	Additionally, network operators' subscription rights trading	Flexibility product defined in terms of power	Flexibility product defined in terms of power	The IDCONS is a combination of a sell and a buy order in the IDM	Compensation for RES curtailment acted as a price cap	Four distinct products differing in their parameters	Specific product options per tender with different evaluation weights

Source: JRC analysis.

5.3. Market design

A consolidated view of the key aspects of market design among the local flexibility markets reviewed is provided in Table 12.

All of the local flexibility markets reviewed are organised spatially in local congestion zones, in which offers can be aggregated in portfolios, similar to the zonal organisation of the wholesale market. A marginal exception is seen in the ENEDIS tenders, in which certain connection points inside the zone may be exempted for technical reasons. On the other hand, GOPACS goes further, combining firm congestion zone configurations with ad hoc formation of IDCONS when necessary, based on the locational information of offers.

The level of harmonisation of long-term trading of flexibility among the markets reviewed is extremely low, with the frequency of calls, evaluation criteria and products differing completely. This mimics the situation regarding long-term contracts for system services such as capacity remuneration mechanisms, in which national specificities play a decisive role. An interesting question is whether or not price caps should be published and made available beforehand to the tenderers: on the one hand, this provides transparency, fostering liquidity, while, on the other hand, it can increase procurement costs for buying network operators, especially in immature markets. Of equal importance is how these price caps are defined: for this, a harmonised methodological framework is missing.

Short-term flexibility markets are more harmonised, with continuous pay-as-bid trading being the standard. Nevertheless, there are some noticeable differences. The start of trading depends on whether the buying network operators publish their flexibility demand, which is a combination of forecast accuracy (which is better the closer to real time forecasts are made), procurement cost expectation (which, in most cases, is higher closer to real time) and liquidity (immature markets require longer trading periods). The gate closure time depends a lot on the level of integration with wholesale markets: GOPACS, which utilises flexibility offers submitted in the intraday market, has the shortest gate closure time. On the other hand, the Nordic marketplaces chose a nominal gate closure time of 2 hours exactly so as not to coincide with the balancing market. The MTU follows the imbalance settlement period, so it can be expected to become 15 minutes in the future in all cases. Another interesting aspect is the manner that the buying party (network operators) participates in the trade: two main approaches can be identified in this regard.

1. Network operators implicitly ‘bid’ by considering a shadow price cap above which flexibility offers are rejected. This is the case when there is an alternative for solving the congestion, such as in the case of sthlmflex (temporary subscription rights) and enera (rule-based cost of RES curtailment).
2. In IntraFlex and NorFlex, network operators try a more direct approach with active bidding for fostering economic efficiency and a reduction of procurement costs. Moreover, in the latter case (NorFlex), this is done in an automatic way through a robot showing a high level of sophistication.

Active bidding is especially noticeable, as no other European market-based procurement mechanism for grid and/or system services network operators currently features a similar arrangement.

The integration of the emerging local flexibility markets with wholesale and TSO ancillary services is ongoing and among the most challenging issues. Long-term tenders so far focus solely on services provided to DSOs. In short-term trading, different levels of integration are seen. At the forefront is GOPACS, which utilises offers from the intraday market, as long as these have locational information and are submitted to a connected power exchange. Nevertheless, in the GOPACS project, flexibility provision is disconnected from balancing services, following the arrangements at wholesale level. In the Nordic pilot projects, unused flexibility offers are passed on to the TSO mFRR market. Thanks to the integration of system balancing and the transmission congestion management procurement mechanism in the Nordics, distributed flexibility can be used for both services. On the other hand, when FSPs must optimise their portfolio, they need to decide how to allocate their capacity between participation in the wholesale energy market and the local flexibility market, making value stacking more difficult.

Except for the case of GOPACS, in which a closer coordination mechanism between the TSO and DSOs has been implemented (even though this is still a long way from co-optimisation of the procurement process), DSOs have precedence in the procurement of distributed flexibility with respect to TSOs. Even though this may not be the most economical solution, it is clearly easier to implement.

Finally, the investigation in this report provided some insights into the expected ‘merit order’ of flexibility services. Flexibility procurement cost is expected to be lowest for market parties, followed by the TSO and finally the DSOs. This is logical, given that the DSOs need flexibility with a locational ‘premium’ coming from a more limited resource pool.

Table 12: Consolidated view of market design specifics among the reviewed flexibility markets

Design characteristic	sthlmflex	IntraFlex	NorFlex	GOPACS	enera	UK tenders	ENEDIS tenders
Locational organisation	Congestion zones	Congestion zones	Congestion zones	Congestion zones and connection points	Congestion zones	Congestion zones	Congestion zones (not all points eligible)
Long-term contracts	X	—	—	—	—	X	X
Evaluation criteria	Availability offer	—	—	—	—	70 % price / 30 % technical criteria	On price except for voltage-related tenders
Call-up	Once per year	—	—	—	—	Twice per year	Ad hoc
Price caps	Published	—	—	—	—	Published	Non-published
In all cases, the pricing mechanism is pay-as-bid for both the availability and the activation components							
Short-term market	X	X	X	X	X	—	—
Start of trading	D-7	D-7	D-7	D-1 to T-6h	D-3 to T-1h	—	—
Gate closure time	Nominal 120 minutes, in practice at 09.00 D-1	90 minutes	120 minutes	As per Intraday Market	Nominal 15 minutes, in practice some hours before	—	—
MTU	60 minutes	30 minutes	60 minutes	15 minutes	15 minutes	—	—
DSO trading	Implicit price caps	Active bidding	Active bidding	None	Implicit price caps	—	—
In all cases, continuous trading is employed, evaluation of offers are made based on price and the pricing method is pay-as-bid							
Buying parties							
DSO	X	X	X	X	X	X	X
TSO	For balancing and congestion	—	For balancing and congestion	For congestion	For congestion	—	—
BRPs	—	—	—	X	—	—	—
Network operators' coordination							
Procurement rule	DSO over TSO	N/A	DSO over TSO	Separate procurement	DSO over TSO	N/A	N/A
Security coordination	Subscription rights	None	To be developed through the FDR	TSO/DSO analysis	Cascading top-down	None	None

D-1 means 1 day before delivery, T-6h means six hours before delivery
Source: JRC analysis.

5.4. Activation and settlement procedures

Table 13 provides a consolidated view of the activation and settlement procedures among the local flexibility markets reviewed.

Baselining is one of the most critical issues for a robust framework on the exploitation of distributed flexibility (CEDEC et al., 2021). This is mainly because distributed resources do not generally take positions in the wholesale market against which the change in generation or consumption patterns (i.e. the supply of flexibility) can be measured. Therefore, it also relates to the level of integration of the various markets in which DERs participate, which for local flexibility markets is rather low. GOPACS constitutes a notable exception by carrying offers over directly from the wholesale intraday market.

The examination revealed that FSP declarations are permitted in all of the local flexibility markets reviewed, complemented in some cases by a baseline option defined by the market or the buying network operator(s). This is interesting given that it is also the method most prone to gaming, as FSPs can declare distorted baselines, overestimating the actual flexibility provided. Nevertheless, it is generally preferred by many FSPs, and it is considered more precise, especially for dispatchable assets (distributed generation or storage). In many projects, network operators develop various surveillance methods, including a review of the baseline forecast methodology of the FSPs, a comparison of FSP baseline declarations with historical measurements and statistical analysis. Regarding market- or network-operator-defined baselines, the default method is based on historical measurements (with and without same-day adjustments). It is noted that certain FSPs, especially smaller ones and/or those with mainly demand response assets, prefer such externally defined baselines, at least as an option. The question here is whether or not market and/or network operators can (or should, considering the associated cost) develop the necessary sophistication for making baseline forecasts per connection point and/or flexibility asset under a scenario of an expanding volume of flexibility provision. Another ongoing issue is the alignment of baseline methods for services provided to different network operators (e.g. the TSO as opposed to DSOs).

A relevant issue is also the meters employed for the settlement of flexibility provision. While, in wholesale markets, connection meters are always employed, some of the local flexibility markets reviewed permit measurements from the appliances' submeters too, owing to requests from the involved FSPs or, in the case of NorFlex, network operators' preferences. The main argument is that a more precise assessment of the flexibility provision is possible, given that the flexibility assets' response is disengaged from the non-controllable consumption and/or generation behind the main meter. While this has a lot of merit from a technical point of view, it is a grey area in regulatory terms, because of data ownership, privacy and measurement data integrity considerations. Another obstacle may be data format and communication protocols, as interoperability standards for smart devices are only now being developed. Nevertheless, the pan-European network associations are quite open to employing submeter data for the settlement of distributed flexibility, in all markets, possibly in combination with main meter readings (CEDEC et al., 2021).

The settlement period usually follows the imbalance settlement period, except in the case of the IntraFlex and NorFlex projects, in which flexibility products have been defined in power terms and high-granularity measurements of 1 minute are employed. Again, this is a notable divergence from the wholesale markets, in which all activation products are defined in energy terms.

Most of the local flexibility markets reviewed do not impose penalties for partially delivered flexibility, and instead impose only reduced remuneration according to the same pattern: full remuneration is awarded above a certain level without overcompensation for over-delivery, zero remuneration below a certain level and a linear reduction in between. However, the specific limits differ significantly among the markets reviewed. The decision not to impose penalties is mainly oriented towards market uptake facilitation, rather than being a principled opinion. In fact, in most cases, the interviewees held the view that, as local flexibility markets mature, penalties may need to be introduced, starting from the availability products. Again, the harmonisation of remuneration and penalty rules for flexibility provision is still an ongoing issue, at least at national level.

In the majority of the local flexibility markets reviewed, balance responsibility is undertaken by BRPs and not by the independent aggregator. Even though this can result in cross-subsidisation, it seems that current flexibility volumes are rather low and, in the case of upwards flexibility, it does not create a significant financial risk for the BRPs. Regarding compensation by the independent aggregator to the supplier/BRP for the energy pre-bought by the latter in the case of demand response, a rather disparate picture is emerging from the investigation, ranging from a well-defined regulated approach (e.g. in France) to no action at all (e.g. in the United Kingdom). Again, significant factors for addressing the issue (or not) are the volume of flexibility with respect to the natural variability of demand and the integration of distributed flexibility and of the independent aggregator business model within the other electricity markets (wholesale, balancing and capacity remuneration mechanisms).

Table 13: Consolidated view of settlement procedures among the reviewed flexibility markets

Procedure	**sthlmflex**	**IntraFlex**	**NorFlex**	**GOPACS**	**enera**	**UK tenders**	**ENEDIS tenders**
Baselines							
FSP schedules	X	X	X	As per wholesale market rules	X	X	X
Market/network operator defined	X	X	—		—	X	X
Market surveillance	X	—	X	—	X	—	X
Metering							
Connection meter	X	X	—	X	X	X	X
Sub-meters	X	X	X	—	—	—	—
Settlement period	60 minutes	1 minute	1 minute	15 minutes	15 minutes	30 minutes	30 minutes
Flexibility partial delivery							
Compensation	Full > 80 % Zero < 40 %	Full > 95 % Zero < 63 %	Full > 80 % Zero < 50 %	Pro rata	Full ≥ 100 % Zero < 100 %	DNO and product specific	Tender specific
Penalties	No	No	No	Imbalance price	Yes (equal to 0)	No	NEBEF rules
Independent aggregators–BRP relationship							
Balance responsibility	BRPs	BRPs	BRPs	As per wholesale market rules	BRPs	Voluntary accreditation system	FSP
Energy compensation	No	No	Future development		Bilateral agreements		NEBEF rules

Source: JRC analysis.

6. Critical notes on the evolution of local flexibility markets in Europe

In this chapter, criticalities regarding the current state and possible evolution of local flexibility markets in Europe are discussed, based mainly on the interviews conducted in the context of this work, along with a more general desktop review of the subject.

6.1. State of evolution of local flexibility markets in Europe

Local flexibility markets in Europe are currently in the emerging phase. While in the United Kingdom and in the Netherlands, they have reached a business-as-usual state, in the rest of Europe they are at the pilot project stage with various levels of ambition, with the most developed examples encountered in the Nordic countries. One could expect a larger deployment of market-based procurement of distributed flexibility for network services given both the mandate of the electricity directive and the considerable number of national and European projects on the subject (for the latter, the interested reader is invited to see Dikaiakos (2020) and Frontier Economics and ENTSO-E (2021)).

Three main drivers behind the need to develop local flexibility markets have been identified in this work:

1. short- and long-term 'freeing' of distribution capacity for accommodating the electrification process (e.g. in the two Nordic projects);
2. unlocking the flexibility potential in the distribution system for congestion management services mainly in the transmission system (e.g. GOPACS);
3. the management of the distribution grid under increased penetration of distributed vRES facilities (e.g. the enera project and the ENEDIS tenders).

Rapid electrification creates an immediate demand for congestion management solutions in the distribution grid. While the long-term (optimum) solution will probably include classic network expansion, utilisation of distributed flexibility offers a quick way forwards for accommodating the increased electricity demand. Therefore, the main driver is not only (or mainly) economic efficiency in the management of the distribution network; it also includes respecting the fundamental responsibility of DSOs to serve existing and new customers.

With large conventional plants retiring owing to the decarbonising process, as well as technical, regulatory and policy factors favouring the proliferation of DERs, utilising the latter's capability for system and network services at transmission level will become increasingly important. The pace of this process will depend fundamentally on the evolution of all underlying factors: the rate of decommissioning of transmission-connected conventional plants, infeed variability and ancillary services provision by new large RES plants ([84]), the state of the transmission network, lead times for network expansion, and the proliferation pace of DERs.

Perhaps unexpectedly, this investigation showed that management of the distribution network under increased distributed vRES penetration is the least pressing driver for the development of local flexibility markets. Under such conditions, the utilisation of local flexibility focuses instead on economic efficiency rather than on maintaining operational security: the network operators usually have other options for the latter, such as flexible connections or, in the worst case, rule-based forced curtailment of vRES – an instrument widely employed (e.g. in Germany).

The drivers behind the development of a local flexibility market significantly affect decisions on a range of issues. The first driver (rapid electrification) implies that key relevance is attached to market liquidity increase. A laxer framework regarding the contractual relationships between independent aggregators and BRPs is accepted, also considering that upwards flexibility currently poses a low financial risk for the latter. Partial delivery of flexibility is not penalised, and reduced remuneration is imposed only under a certain threshold (e.g. below 80 % in the Nordic projects). Moreover, products such as weekly contracts are introduced, with the explicit aim of attracting additional market players / flexibility volume.

If the key aim of the local flexibility market is congestion management in the transmission system, key considerations include integration with the wholesale market, the regulation of contractual relationships between independent aggregators and BRPs, the MTU and settlement period, and penalty rules for partial delivery of flexibility. A characteristic case is GOPACS, which is the most integrated with the wholesale market structure.

([84]) The latter factor will depend mainly on overall market design rather than technical capabilities, which are already mostly present. Disentanglement of the revenues of large RES plants from short-term electricity markets will dampen the attractiveness for providing ancillary services.

Finally, even in the more mature cases (e.g. in the UK flexibility tenders), available flexibility provision cannot cover all of the demand, at all times, of network operators, at least within economically acceptable limits. The main reason is business case immaturity, both in general terms (i.e. concerning distributed flexibility per se) and with specific regard to flexibility services to DSOs. However, there are indications of underlying technical-economic reasons, too: while most of the network operators interviewed were convinced of the considerable flexibility potential in the distribution system, factors such as the cost of the required intelligence for aggregation (e.g. baseline forecasts and interoperability requirements between devices and systems) and variations in the time demand response capability (e.g. in respect of external temperature or during peak commuting times) reduce the available resource in practice. This implies that a combination of tools will be needed for the management of the distribution system during the energy transition, both in the long term (i.e. network expansion) and in the short to medium term (i.e. flexible connections or preferential network tariffs for demand curtailment availability, as a security back-up to local flexibility markets).

6.1.1. Shift towards short-term local flexibility markets

Even though the current state of play of local flexibility markets in Europe does not permit a definitive view on their future characteristics, a key outcome from all of the interviews conducted in the context of this work is the expectation of moving into short-term spot markets. Longer term contracts through tender procedures will continue to be procured in many cases in the mid-term as a reliability back-up and as the most obvious way to incorporate flexibility into the long-term development of distribution networks. However, as the liquidity of distributed flexibility increases and DSOs get more experience in it, short-term (i.e. less than 1 week ahead) spot markets will probably become more important in the overall procurement process. Reasons behind this include:

— an increase in liquidity by offering the possibility to smaller assets (e.g. EVs) to participate in the procurement process. This is because such assets can have a good forecast on their flexibility potential only close to real time;

— a lower volume risk for network operators owing to better grid forecasts closer to real time;

— expectations of better price formation, although evidence from the flexibility markets reviewed showed that, in some cases, longer term contracts led to lower activation prices than short-term markets in projects in which both mechanisms coexist; nevertheless, given the state of play of these projects, this evidence may be circumstantial.

A significant barrier to the development and consolidation of short-term markets as the main procurement mechanism for local flexibility is the current difficulty of integrating them with wholesale markets, which is discussed in more detail in the next section.

6.2. Level of integration of local flexibility markets with wholesale markets

Given the emerging character of local flexibility markets, their integration with wholesale electricity markets is, in most cases, low, with the notable exception of GOPACS. Most of the projects reviewed extend, at best, to coordination with the TSO flexibility services market (i.e. for balancing and/or congestion management), employing a hierarchical structure in which the DSOs always take precedence in the procurement of flexibility. While co-optimisation of flexibility procurement for grid services has been identified as the end goal by all interviewees, it seems we are still a far way from that. The reasons for this, and its impacts, are discussed in more detail below.

6.2.1. State of integrated security analyses among different network operators

The level of TSO–DSO coordination regarding operational security analyses is one of the fundamental factors defining the level of coordination in flexibility procurement. Mainly owing to legacy organisational structures, originating from the old unidirectional power system, each network operator until recently was to a great extent responsible for the operation of its own part of the network, with little interaction with the other network operators. Network codes, and especially the system operation guideline ([85]), as well as the overarching principles set in the clean energy package, were milestones towards closer coordination between TSOs and DSOs, regarding power system operation and planning of both. Nevertheless, we are in the implementation phase of all relevant changes.

([85]) Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation.

TSOs have generally reached a high level of sophistication of operational security analyses, having the capability for almost continuous real-time assessments of the state of the transmission network, increasingly better forecasts regarding the relevant probabilistic variants (e.g. RES output) and enhanced controllability capabilities through the deployment of smart grid technologies (e.g. phase-shifting transformers). This is not the case for distribution systems in Europe, for which the main problem is probably the lack of observability, an increasingly salient issue at lower voltage levels. This considerably affects the procurement processes for flexibility by DSOs regarding required volume, time of procurement and type of requested products. The less accurate the operational security assessment is, the more flexibility has to be procured as a safety margin, and availability products procured long in advance are favoured.

The disparity of network operational 'intelligence' between transmission and distribution systems makes a hierarchical, cascading coordination structure the only practical choice at present. Relevant to this is also the lack of data and communication protocols harmonisation, with CIM implementation identified in all network levels as the main solution. However, this will take time and may also impose undue transition burdens on FSPs, especially the smaller ones.

6.2.2. Emergence of transmission/distribution system operator competition for flexibility services

A first glance, in the current structure of markets for flexibility coming from assets in the distribution system, it may appear that DSOs are favoured, either by setting up a market in which they are a monopsony or by having precedence in the procurement process against the TSOs. However, this is a misleading view: the key indicator is the liquidity of flexibility offers to DSOs against offers by DERs to TSOs.

Wholesale markets, including for system services, are much more mature than the emerging local flexibility markets for services to DSOs, representing a much clearer business model for FSPs. Moreover, there are instances in which the remuneration for system services is much higher than the expected remuneration for services in the distribution system: this is, for example, the case in France, where participation in the capacity remuneration mechanism represents quite a lucrative business opportunity, leaving little interest in participation in the new flexibility tenders for services in the distribution system (also considering the price cap defined by ENEDIS). In addition, under the current state of networks in Europe, there are cases in which distribution systems have less demand for flexibility services than the system for frequency ancillary services or the transmission network for congestion management (see, for example, the flexibility volumes procured in GOPACS by the TSO as opposed to the DSOs), making a weaker business case regarding revenue flow certainty for FSPs.

Liquidity problems for local flexibility markets can be expected to be more acute when these are disengaged completely from the rest of wholesale markets. A hierarchical, cascading system in which DSOs have precedence in the procurement process over TSOs can be a practical way forwards, as unused FSP offers are automatically transferred to the latter. A complementary measure could be collaboration between DSOs and TSOs in the utilisation of services offered by distributed assets to the latter: an example could be the obligation of DERs participating in the capacity remuneration mechanism to also offer their flexibility to the DSOs (i.e. for the capacity remuneration mechanism to act simultaneously as an availability product at both system and distribution network level).

In practice, however, prices for wholesale ancillary and transmission system congestion management services constitute an opportunity cost for FSPs when they contemplate their offers to emerging local flexibility markets. This has to be acknowledged by DSOs and can be a good initial guide for assessing the competitiveness of flexibility against other options such as classic network investment. This also highlights the importance of steps towards co-optimisation of the procurement of services to network operators (both DSOs and TSOs) as a means to drive costs down, especially for DSOs.

6.2.3. Barriers to flexibility service provider value stacking

Most of the interviewees were of the opinion that the provision of local flexibility services to DSOs does not provide enough revenue streams to make a viable business case for FSPs on their own. Therefore, value stacking is critical for increasing the flexibility offered by DERs.

Taking into account the general structure of the European internal energy market for electricity, a market party must in general optimise its portfolio among a multitude of energy and ancillary services markets ([86]). An

([86]) As a general rule, the different electricity markets in Europe include capacity remuneration mechanisms, over-the-counter contracts, forward markets, day-ahead markets, intraday markets, balancing capacity markets, balancing energy markets, market-based procurement for congestion management in the transmission system and, finally, local flexibility markets.

important point is that these markets are separated (i.e. a market party has full responsibility for how to position its assets among different time frames and products for maximising its profits). This disjointed market architecture is a rather distinctive feature of the European electricity market set-up. In other jurisdictions (e.g. in the United States), co-optimisation in the procurement of different products is the norm, with energy trading in the day-ahead market being co-optimised with reserves provision and transmission capacity allocation.

While the European framework gives much more freedom to market parties, portfolio optimisation may prove a daunting task, especially for emerging parties such as small FSPs. For local flexibility markets, in particular, this comes on top of technological challenges such as accurate baseline prediction, which adds risks to an emerging and not yet consolidated business model. The integration of flexibility procurement at DSO and TSO level (with better coordination in the form of a common order book as an intermediate step) could facilitate value stacking for FSPs, with beneficial effects for the liquidity of distributed flexibility.

6.3. Role of the regulatory framework in the development of local flexibility markets

National regulatory frameworks play a major role in empowering DSOs to take a more active role both as buyers of distributed flexibility and in facilitating others' use of flexibility resources in their own networks to enable system-wide benefits. In all of the countries analysed in this report, DSOs' revenues models are based on incentive regulation using a TOTEX approach. In addition, DSOs' efficient cost (TOTEX in most of the countries analysed) is benchmarked against comparable DSOs in terms of several outputs, such as the quality and reliability of supply and efficient network operation (the level of network losses), to account for more cost-effective operation and planning of their distribution networks. This regulatory framework provides incentives to DSOs to investigate solutions for the operation and planning of their networks beyond classic network expansion.

Furthermore, R & D represents a critical part of the innovation incentives provided to the DSOs and, more specifically, of the way this cost is treated within the DSOs' revenue model. In most of the EU countries analysed (e.g. France, Germany, Norway and the United Kingdom), R & D cost is partially recovered by increasing the revenue allowance upon compliance with a set of eligibility requirements and directly passed through tariffs (and therefore is not subject to efficiency benchmarking).

In the United Kingdom, there is a clear regulatory impetus for the deployment of flexibility solutions (mainly market-based), among others, through the NIA used to finance small R & D and demonstration projects and the IRM to fund roll-outs of trialled innovations that have environmental benefits and provide value for money for consumers. Both cases are financed through yearly adjustment to the revenue allowance. Furthermore, NIC is competition through which few large development and demonstration projects run by TSOs and DSOs are selected for funding. To a significant extent, the quick development of local flexibility markets in the United Kingdom can be attributed to the supportive regulatory framework.

To further facilitate innovation, most of the countries analysed have also implemented regulatory experimentation, usually in the form of regulatory sandboxes. Some of the local flexibility markets/projects, such as NorFlex (Norway) and enera (Germany) have been developed owing to a regulatory sandbox. It is noted that regulatory experimentation is not constrained solely to market-based procurement of distributed flexibility, but in some cases includes other procurement methods (e.g. pilot regulation on network tariffs in Sweden).

Of relevance to the development of local flexibility markets is also the existence of a regulatory framework for the participation of demand-side flexibility in all electricity markets, and more specifically the emergence and market access of independent aggregators. In this context, France is one of the leading countries in Europe with a regulatory framework for demand-side participation, which has been in place since 2014. Demand-side flexibility and independent aggregators can participate in the day-ahead and intraday, balancing, capacity, and TSO and DSO congestion management markets. Similarly, the regulation in the United Kingdom allows access of independent aggregators to almost all markets, except wholesale markets (day-ahead and intraday). In Germany and the Netherlands, access of independent aggregators is limited to participation in the balancing market, whereas, in the Nordic countries (Norway and Sweden), no independent aggregators are commercially active in any electricity market. Independent aggregators are, in principle, allowed to participate in local flexibility markets, but many issues around their participation, such as balance and financial responsibility and the transfer of energy, are not yet clearly regulated, except for in France. However, in France, the results of local flexibility tenders have been rather disappointing so far. All in all, how the business case for the provision of local flexibility services will be affected when a more consolidated regulatory framework for the financial relationships between independent FSPs and suppliers/BRPs is established is an ongoing issue to be considered.

7. Conclusions

Growing renewable energy generation levels and electrification of end-use sectors, such as transport and heating, affects the ability of DSOs to ensure smooth operation of their networks, with the ageing of European distribution networks an additional complicating factor. In this respect, flexibility procurement presents an alternative to classic network investment that could be, in some cases, more economically advantageous and quicker to implement than network expansion.

The EU electricity directive describes market-based procurement of flexibility services by DSOs as the preferred option, whereas CEER takes a more conciliatory approach, considering all options (market based, rule based, network tariffs and connection agreements, or a combination thereof) as equal alternatives. Currently, flexibility procurement for distribution network operation and planning is under development, with various degrees of maturity and a variety of methods employed among European countries. The regulatory framework for DSOs' revenues and the specific national situation of the distribution network play a significant role in the level of flexibility procurement and in the preferred method(s).

Market-based procurement of flexibility services by DSOs is still a niche practice in most countries. Among the cases reviewed in this report, three countries (France, the Netherlands and the United Kingdom) take a business-as-usual approach to market-based procurement, two (Norway and Sweden) have developed pilot projects and, in Germany, a rule-based approach was in the end chosen as the main option. Nevertheless, even among the countries in which market-based procurement can be considered to have reached a business-as-usual stage, there are significant discrepancies in terms of procured volumes and levels of market maturity: DNOs in the United Kingdom systematically procure local flexibility services and in increasing volumes each year, backed by a supportive regulatory mandate. In the Netherlands, GOPACS is a well-established mechanism, and the recent collaboration with EPEX SPOT is expected to further increase liquidity in the market for flexibility services by assets in the distribution system. On the other hand, the flexibility tenders in France have produced rather disappointing results so far, owing to, among other things, more attractive business alternatives for FSPs, as well as the design of the tenders (specific, non-divisible products) and the price caps imposed by ENEDIS.

Even though local flexibility markets are, at best, at a maturing stage, certain initial insights on emerging trends regarding their design characteristics can be gleaned.

- Regarding pre-qualification procedures (and the part of settlement processes that deals with flexibility delivery verification), the concept of the FDR seems to be popular. Nevertheless, a potential barrier for FSPs may be the different requirements for participation in local flexibility markets, on the one hand, and in the wholesale, balancing and capacity markets, on the other. In this respect, requirements on data interoperability by network operators and data ownership by regulators will probably play a critical role.
- Regarding market architecture and flexibility product design, long-term contracts (seasonal and longer) seem better for addressing network deferral and reliability services, while short-term markets seem more suitable for operational support, such as congestion management services. While a good level of convergence on short-term products is emerging, long-term contracts vary widely among the local flexibility markets reviewed. Trade is generally organised in local congestion zones, and short-term trading follows the continuous, pay-as-bid paradigm. A harmonised methodological framework for setting price caps is missing, with each jurisdiction following its own approach. Regarding penalties for partial delivery of flexibility, again there are significant differences: pilot projects tend to enforce only a (mostly proportional) reduction in remuneration (with the exception of the enera project, in which remuneration fell to zero for any level of partial delivery), while, in France and the Netherlands, there are financial penalties. The United Kingdom follows the first approach, even though it can be considered the most mature local flexibility market, although this could change in the future.
- On settlement procedures, baselining seems to be one of the most critical issues. Network operators still experiment with different methods, but FSP declaration is in almost all cases one of the options. When this is followed, verification processes are established that try to mitigate potential gaming opportunities, but these usually necessitate the recording and processing of a large number of data, including local meteorological conditions. Also critical will be whether settlement will be permitted based on submeter measurements, for which end customers and FSPs should consent to providing data on an asset basis rather than a connection point basis.

The integration of local flexibility markets with wholesale and balancing markets and security coordination between DSOs and TSOs are still ongoing issues. Three distinctive cases can be discerned.

1. A local flexibility market in which the DSO is a monopsony. This is the case for France and the United Kingdom. While the development of security coordination between the distribution and transmission systems when DSOs procure flexibility is among the stated future goals in both cases, so far it is implicitly considered that, backed so far by experience, flexibility activation for solving network constraints in the distribution system does not cause noticeable issues in the transmission system, mostly because of the relatively low volumes.
2. A local flexibility market in which the DSO has precedence in the procurement. This is the case in the pilot projects of Germany, Norway and Sweden, where DSOs pass unused offers to the TSO. This also implies a cascading security coordination process.
3. A local flexibility market in which both DSOs and the TSO procure distributed flexibility on an equal footing. This is the case in the Netherlands, which, among other things, necessitates a coordinated security analysis between the network operators involved.

The partial, at best, integration of local flexibility markets with the rest of electricity markets is problematic in two main ways. First, value stacking for FSPs becomes more difficult. Second, distributed flexibility is not necessarily optimally procured between the different network operators. Both factors involve the risk of an emerging suboptimal competition for flexibility coming from assets in the distribution system between DSOs and TSOs, with the former so far at a disadvantage, given that markets for system (TSO) ancillary services are much more mature. For the business-as-usual local flexibility markets, this has particularly been the case in France, but such indications also exist in the United Kingdom and in some of the pilot projects reviewed in this report. The issue of possible market fragmentation pertains also to the Netherlands: while GOPACS can be considered the most integrated local flexibility market for congestion management services to both DSOs and the TSO, a parallel platform, Equigy, is planned as a means for procurement of distributed flexibility for system balancing services.

As regards the risk for market fragmentation, there are indications of a risk of regulatory fragmentation regarding the participation of FSPs in different markets, particularly independent aggregators. The survey and interviews conducted in this work showed that, in most cases, BRPs assume balance responsibility, while compensation for ToE does not exist. This can be attributed to the emerging nature of local flexibility markets, many of which are pilot projects, as well as the fact that, in most cases, regulation for independent aggregators is only now being developed. In addition, an ongoing issue is how the liquidity of local flexibility markets and the price of services may be affected when the regulatory framework on aggregation becomes consolidated.

Regarding the relationship between the regulatory framework and the development of local flexibility markets, only initial comments can be made in this work. In all of the cases examined, an incentive-based framework exists for the DSO revenue model. This helps DSOs to investigate methods other than classic network investment for the operation and planning of their networks, although to various degrees owing to the significant differences in the specificities of the national regulatory frameworks. The analysis also showed that innovation incentives, including regulatory experimentation such as in the form of sandboxes, can be very helpful in the first steps of local flexibility markets. Finally, we have to note that the United Kingdom represents a distinctive case, as it has a regulatory mandate and policy vision clearly promoting the use of flexibility, which to a significant extent explains the relative success of local flexibility markets in this jurisdiction.

7.1. Future work

This work reviewed specific cases of local flexibility markets. The choice of cases reviewed was based on a combination of the level of maturity, distinctive features and insights ([87]) gained into the development of local flexibility markets in Europe. It is noted that a series of major Horizon projects on distributed flexibility are ongoing and their results are expected to play a significant role in the development of local flexibility markets (we refer here to Coordinet ([88]), OneNet, Interrface, Platone and EUniversal). Therefore, future work should incorporate these projects too. A decisive question is how many of these, as well as of the pilot projects reviewed in this report, will lead to business-as-usual local flexibility markets? In addition, if they do not lead to business-as-usual local flexibility markets, what are the underlying reasons for this? Moreover, the analysis should probably expand to market platforms aiming to procure distributed flexibility for system and network services

([87]) This was, for example, the case for the enera Flexmarkt, which, albeit a pilot project without continuation, stands as an alternative to the final decision taken in Germany to follow a rule-based approach for congestion management services.

([88]) While Coordinet was reaching its end in June 2022 and the pilot projects developed in its context were mature enough to be reviewed, the authors chose to focus on sthlmflex, which can be considered a spin-off of the Swedish cases.

beyond those aimed at DSOs (e.g. the Equigy platform) and the interrelation of such initiatives with local flexibility markets.

A second major work stream was a deeper assessment of the regulatory framework pertaining to distributed flexibility, including the provisions on independent aggregators. This work showed that the risk here of regulatory fragmentation between different services/markets and/or EU countries was substantial. In this regard, a significant role will be played by the network code for demand response that is currently under development ([89]) and its national implementations.

Finally, a third major future work stream should probably be a more detailed examination of the data management requirements on distributed flexibility at both the technical (e.g. harmonisation of communication protocols and IT systems) and the regulation (e.g. data ownership and data privacy provisions) levels. Both of these issues have been touched upon in this report, but the importance and depth of the subject, closely related to the EU action plan for digitalising the energy sector ([90]), deserves a stand-alone, dedicated analysis.

([89]) https://www.acer.europa.eu/events-and-engagement/news/acer-initiates-drafting-new-framework-guidelines-demand-response
([90]) https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/13141-Digitalising-the-energy-sector-EU-action-plan_en

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List of abbreviations

aFRR	automatic frequency restoration reserve
API	application programming interface
BRP	balance responsible party
BSP	balance service provider
CAPEX	capital expenditure
CEDEC	European Federation of Local Energy Companies
CEER	Council of European Energy Regulators
CIM	common information model
CRE	Commission de Régulation de l'Énergie (French regulatory authority)
DER	distributed energy resource
DNO	distribution network operator
DSO	distribution system operator
EAN	European article numbering
E.DSO	European Distribution System Operators
ENA	Energy Networks Association
ENTSO-E	European Association for the Cooperation of Transmission System Operators for Electricity
ETPA	Energy Trading Platform Association
EV	electric vehicle
FCR	frequency containment reserve
FDR	flexibility data register
FSP	flexibility service provider
GOPACS	Grid Operators Platform for Congestion Solutions
HV	high voltage
IDCONS	intraday congestion spread
IRM	innovation roll-out mechanism
LV	low voltage
mFRR	manual frequency restoration reserve
MTU	market time unit
MV	medium voltage
NEBEF	block exchange notification of demand response
NIA	network innovation allowance
NIC	network innovation competition
OPEX	operational expenditure
R & D	research and development
RAB	regulatory asset base
RES	renewable energy source
RIIO	revenues = innovation + incentives + outputs
RR	replacement reserve

SDSP	Smart Data and Service Platform
SGU	significant grid user
SINTEG	smart energy showcase – digital agenda for the energy transition
ToE	transfer of energy
TOTEX	total expenditure
ToU	time of use
TSO	transmission system operator
USEF	universal smart energy framework
VLP	virtual lead party
vRES	variable renewable energy source

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Annexes

Annex 1. Survey on Flexibility Marketplaces in Europe

Personal information

Name and Surname:

Affiliation:

1. Pre-qualification of Flexibility Service Providers (FSPs) and flexibility assets

1.1 When does the prequalification process takes place?

- Before registration into the marketplace
- Before submission of flexibility offers
- After successful flexibility offers are cleared
- No pre-qualification process

Could you provide some more details?

1.2 The pre-qualification process:

- Validates the regulatory, commercial and financial capacity of FSPs
- Validates the technical characteristics of flexibility assets
- Both

Could you provide some more details including which entity is responsible for each part of the prequalification process?

In case of validation of flexibility assets' technical characteristics: Which technical characteristics are verified in the prequalification process? What are the tests performed?

1.3 During the prequalification process are certain assets/locations excluded because activation of flexibility from them would cause operational security violations in some parts of the network?

- Yes
- No

If yes, could you provide some more details?

1.4 Are there minimum nominal capacity limits for the flexibility assets?

- Yes
- No

1.4.1 If yes, how much is the limit (in kW)?

1.5 Are there maximum nominal capacity limits for the flexibility assets?

- Yes
- No

1.5.1 If yes, how much is the limit (in kW)?

1.6 On average, how much time takes the prequalification process (in days)?

1.7 Please provide any other information regarding the prequalification process you consider relevant

2. Procured flexibility services

2.1 At which flexibility services does the marketplace aim? (multiple choice)

- (Long-term) investment deferral
- (Short-term) congestion management
- Resilience (e.g. support to fault-restoration or re-energisation)
- Reactive power/voltage control
- Other (please elaborate)

2.2 What other services could be required in the foreseeable future (i.e. in the next 5 years)? (multiple choice)

- Steady-state voltage control
- Fast reactive current injection
- Inertia for local grid stability
- Short-circuit current injection
- Black-start capability
- Island operation capability
- Other (please elaborate)

2.2.1 For which of the above services do you believe market-based procurement could be the preferred option (e.g. against a rule-based approach)? (multiple choice)

- Steady-state voltage control
- Fast reactive current injection
- Inertia for local grid stability
- Short-circuit current injection
- Black-start capability
- Island operation capability
- Other (please name the services)

3. Trading parties

3.1 Who are the buyers of flexibility in the marketplace? (multiple choice)

- DSOs
- TSO
- BRPs

3.2 Any other comments you deem relevant?

4. Level of aggregation

4.1 The bidding area of the marketplace is organised per:

- DSO responsibility area
- Congestion area (more localised)

4.1.1 What is the highest voltage level in the congestion area (in kV)?

4.2 Offers by FSPs are organised per:

- Delivery points of flexibility assets
- Bidding areas in the marketplace

4.3 Please provide any additional details you consider relevant

5. Flexibility products

5.1 What kind of flexibility products are traded in the marketplace?

- Availability (capacity) products
- Activation (energy) products
- Both

5.1.1 In case availability products are traded:

- The activation price is pre-determined by the bying party (e.g. the DSO)
- The activation price is part of the FSP's offer for the availability product
- FSPs awarded with availability contracts bid freely in the short-term market

5.1.2 In case availability products are traded, what is the maximum procurement horizon (in months)?

5.1.3 In case availability products are traded, what is the minimum procurement horizon (in months)?

5.2 What is the minimum bid size (in MW)?

5.3 What is the maximum bid size (in MW)? (please insert 0 if not applicable)

5.4 Are bids divisible?

- Yes
- No

5.5 What is the Market Time Unit (i.e. minimum activation period) (in min)?

5.6 Are there additional technical specifications for the flexibility products? (multiple choice)

- Notice period
- Time to full activation
- Ramping limits
- Recovery rules
- Other

5.6.1 Could you provide the technical details?

5.7 Please provide any additional details you consider relevant

6. Evaluation and clearance of flexibility offers

6.1 Are offers evaluated based on:

- Price
- Price and other criteria

6.1.1 In case that other criteria are employed too, could you elaborate?

6.2 In the evaluation of offers:

- All offers are considered that have the same effectivenes on solving congestions
- Sensitivity factors are employed

6.2.1 Could you provide some details on the calculation process of sensitivity factors (e.g. timing, method, etc.)?

6.3 Are there price caps above which offers are rejected?

- Yes
- No

6.3.1 In case there are price caps, are these published before flexibility offers submission?

  - Yes
  - No

6.4 The pricing mechanism for capacity products is:

- Pay-as-bid
- Pay-as-cleared
- Other

6.4.1 In case of 'other', please elaborate

6.5 The pricing mechanism for activation products is:

- Pay-as-bid
- Pay-as-cleared
- Other

6.5.1 In case of 'other', please elaborate

6.6 Activation products are traded in:

- Auctions
- Continuous trading

6.6.1 Could you provide some information on the start of trading and the gate closure time?

6.7 Regarding activation products, the network operator:

- Announces flexibility needs in advance and calls FSPs to provide flexibility services
- Activates offers from the oder book without pre-announcement

6.7.1 What is the average time between announcement and activation?

6.8 Please add any additional information you consider relevant regarding evaluation and clearance of flexibility offers

7. Coordination between network operators

7.1 What is the coordination scheme between network operators?

- Non-applicable (in case there is a single byer of flexibility)
- The lower-level network operator has precedence in the procurement of flexibility (e.g. the DSO against the TSO)
- The higher-level network operator has precedence in the procurement of flexibility (e.g. the TSO against the DSO)
- Network operators compete on equal footing (the network operator offering the higher buying price clears the flexibility offer)
- Co-optimisation
- Other

7.1.1 Could you provide some details on the co-optimisation process?

7.2 How is it secured that activations of flexibility will not cause operational security violations in other parts of the network (outside the responsibility of the buyer network operator)?

8. Activation of flexibility

8.1 Does the network operator has direct access to flexibility assets?

- Yes
- No, activation of flexibility is made by the FSP

8.1.1 If activation of flexibility is made by the FSP what are the means of communication between the

network operators and the FSPs (phonecall, e-mail, market platform, other)?

9. Settlement procedures

9.1a What is the measurement period?

9.1b What is the settlement period?

9.1c If the settlement period is different than the measurement period, are the measurements averaged for each settlement period or another method is employed?

9.2 How the baseline is calculated?

- Based on a methodology defined by the market operator and/or the buying network operator
- Based on schedules provided by FSPs
- Both options are permitted

9.2.1 Could you name the baseline methodologies employed?

9.2.2 In case both options are permitted, which one is preferred by FSPs according to your experience?

9.3 Which of the two aforementioned methods (baseline against schedule declaration by FSPs) do you believe that estimate best the actual flexibility provision? In your view, what are their pros and cons?

9.4 At which stage the settlement of availability products takes place?

- Upon offer clearing
- After the activation period and only if activation offers were actually submitted
- N/A (no availability products in the marketplace)

9.5 In case of flexibility not delivered:

- Only a reduction of remuneration applies
- Penalties are imposed

9.5.1 In the case of availability products, do penalties apply only to the activation/energy component or also to the availability/capacity component?

9.6 Please provide any additional information regarding settlement procedures you consider important

10. Financial relationships between FSPs and BRPs

10.1 Can individual end-customers participate in the marketplace without an aggregator?

- No
- Nominally yes, but it is very rare
- It is already done by industrial consumers
- It is already done by industrial and commercial consumers
- It is already done by all types of consumers

10.2 Is participation of independent aggregators permitted in the marketplace?

- Yes
- No

10.2.1 In case that the FSP and the BRP of a flexibility asset are different entities, who assumes balance responsibility for the flexibility provision?

  - The FSP
  - The BRP

10.2.2 In case that the FSP and the BRP of a flexibility asset are different entities, does the FSP compensates the BRP (Supplier) for the energy it offers as flexibility?

- Yes
- No
  - 10.2.2.1 Does the compensation of the BRP is defined by regulation or by bilateral agreements? Could you provide some specifics?

10.3 How the System imbalances caused by flexibility activation are treated?

- They fall into BRP responsibility
- They fall into FSP responsibility
- They fall into network operator responsibility
- Other

10.3.1 Could you elaborate?

10.4 Please provide any additional information you regard relevant on settlement procedures

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