Advancing cross-system solutions to address electricity network challenges

Final report

Trinomics

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Authors

Mohammad Ansarin

Csinszka Bene

Anna Kralli

João Gorenstein Dedecca

Luc van Nuffel

Presented by

Trinomics B.V.

Mauritsweg 44

3012 JV Rotterdam

The Netherlands

Contact person

João Gorenstein Dedecca

E: joao.dedecca@trinomics.eu

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ADMS	Advanced distribution management system
B&D	Bargaining & decision transaction costs
BEMS	Building energy management system
BESS	Battery energy storage system
BRP	Balance responsible party
DER	Distributed energy resource
DERMS	Distributed energy resource management system
DLR	Dynamic line rating
DSF	Demand-side flexibility
FCA	Flexible connection agreement
FSP	Flexibility service provider
GET	Grid-enhancing technology
HEMS	Home energy management system
ICT	Information and communication technologies
P&E	Policing & enforcement transaction costs
RAB	Regulatory asset base
RES	Renewable energy source
S&I	Search & information transaction costs
TYNDP	Ten-Year Network Development Plan

Executive Summary

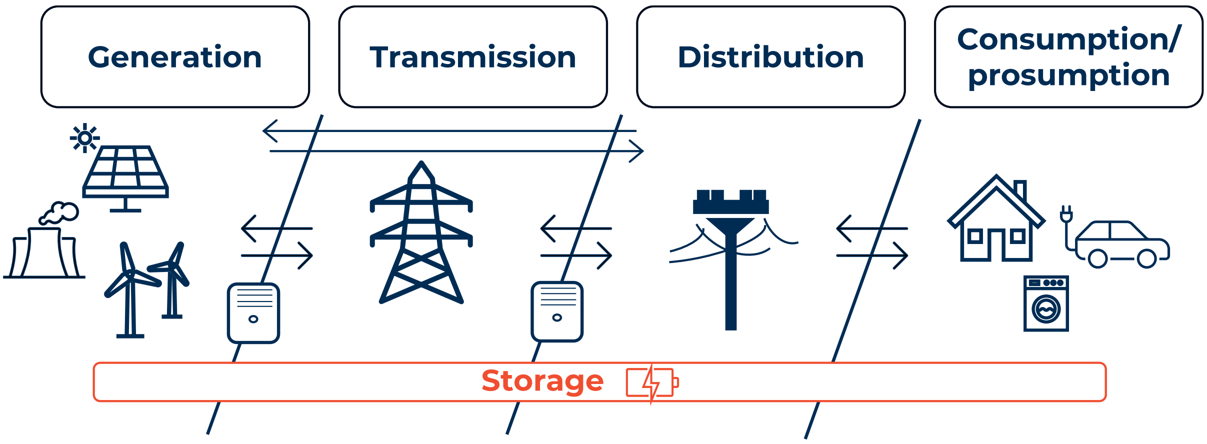
Introduction

The European electricity system faces new challenges. Electricity system operators need to deliver additional network capacity (domestic as well as cross-zonal), while managing volatility due to the massive deployment of intermittent RES which increasingly require balancing and congestion management measures. To accommodate the need for additional grid capacity, transmission and distribution network reinforcements and extensions constitute the classical approach. This option requires huge funding and technical efforts, and the result can be suboptimal if Transmission system operators (TSOs) and Distribution system operators (DSOs) do not efficiently cooperate for their investment planning and operational activities. Therefore, also given the long lead times for new grid investments and their high impacts on network costs for grid users, authorities and actors are paying increasing attention to alternative solutions like grid-enhancing technologies (GETs) and cross-system solutions that allow to reduce and/or defer grid investment needs.

Given the scale of the challenges, a comprehensive strategy, involving all available solutions is necessary (network expansion and reinforcement, GETs, and cross-system solutions). This should allow to efficiently use existing and new network assets and facilitate the connection of new generation, storage and consumption/prosumption assets at reasonable cost and without excessive delays. However, there is still a lack of understanding of alternative solutions, and some countries seem to struggle to achieve optimal use of existing assets despite the availability of mature solutions like GETs. Large-scale deployment of cross-system solutions remains limited due to the perceived complexity of their implementation and high transaction costs, as well as other barriers (for example of regulatory and technical nature). For example, flexible grid connections agreements face high transaction costs towards implementation, which affects their net benefits for both grid users and TSOs/DSOs.

This study aims to provide a better understanding of the solutions available within different electricity sub-systems (see figure 1) other than the network sub-system (see Figure 1**).** The final goal is to maximise the efficiency and effectiveness of networks investments and their operations.

Figure 1 The electricity system and its sub-systems

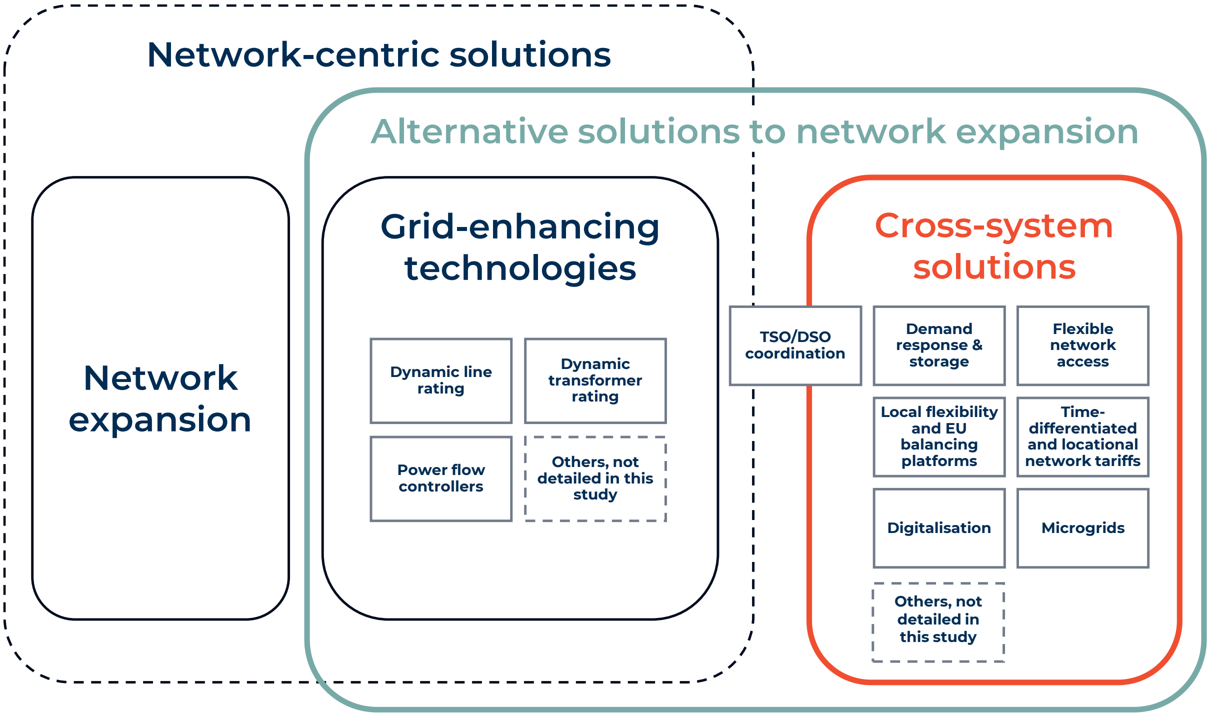


The focus is on characterising cross-system solutions (outside of the network sub-system) addressing the lack of sufficient network capacity or ancillary services' needs, identifying barriers and good practices to the solutions' upscaling (particularly related to addressing high transaction costs), and proposing associated recommendations to stimulate their deployment.

Analysis of alternative solutions to network expansion

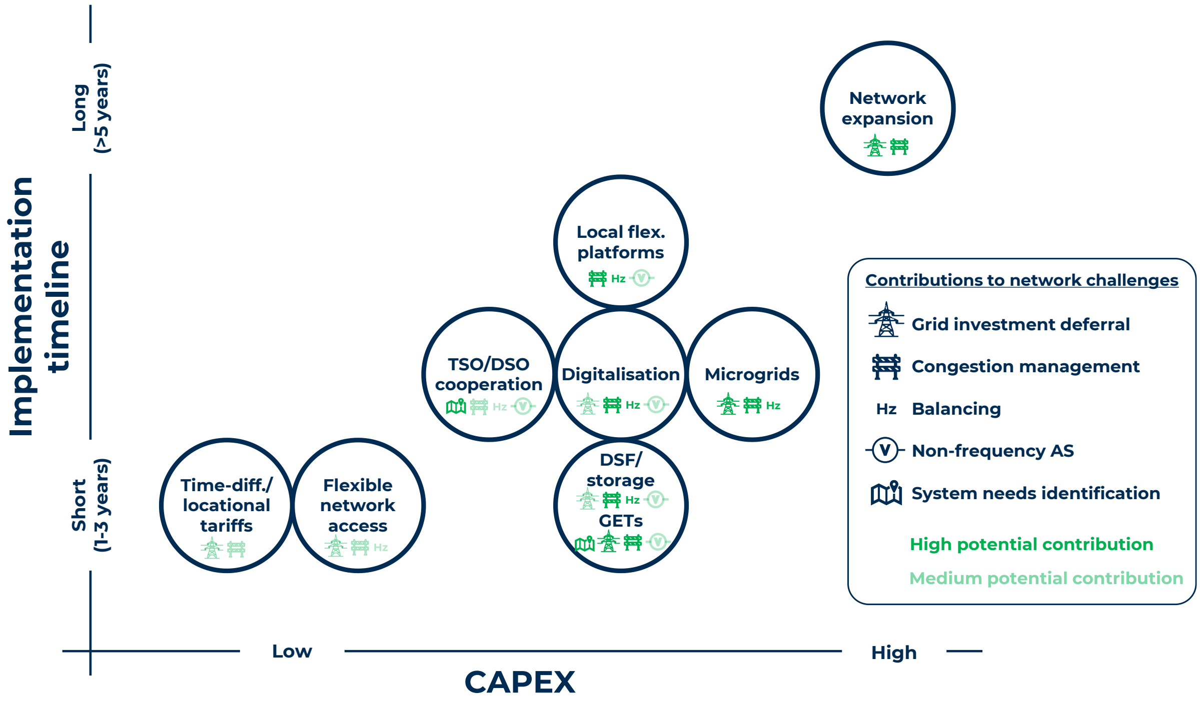
Error! Reference source not found. below illustrates how network-centric, alternative and cross-system solutions are interrelated. The figure includes examples of GETs and cross-system solutions discussed in this study – however, there are other alternative solutions which are (or can be) deployed to reduce grid congestion and investment needs, e.g. flexible operation of electrolysers or hybrid heat pumps.

Figure 2 Network-centric and cross-system solutions to address network challenges



Alternative solutions can provide significant benefits compared to classical network expansion, given their lower cost to address network challenges and faster implementation timeline, among other advantages. Furthermore, alternative solutions serve to meet network operators' flexibility needs. The Figure 3 below compares the implementation timeline, capital expenditure (CAPEX) and contributions to network challenges of each solution (including network expansion and GETs). This figure must be considered with care given the challenges in assessing and comparing the solutions on a general level, but it gives an indication of the considered dimensions. The solutions' contributions to the main group of challenges are separated into 1) identification of system needs, 2) grid investment deferral, 3) congestion management, 4) balancing services and 5) non-frequency ancillary services.

Figure 3 Schematic overview of network expansion versus cross-system solutions (AS: Ancillary Services)



The solutions identified face several barriers, in particular high transaction costs. Table 1 summarises the analysis on transactions for each of the cross-system solutions. Transaction costs have at least a fair impact on the overall uptake of most cross-system solutions.

More specifically:[1]

- Overall, the **search and information** costs necessary to implement most solutions are quite significant (as benefits and costs of solutions for each party are usually not easy to establish and require significant exploration by the involved parties in order to develop the necessary knowledge and identify the appropriate solutions);
- **Bargaining and decision costs** to implement alternative solutions are generally considerably high, given the lack of experience in agreeing contracts for the different novel solutions;
- In contrast, **policing and enforcement costs** are generally low, especially as it is usually rather straightforward to evaluate whether a cross-system solution is satisfying contractual requirements.

The implementation of cross-system solutions is additionally affected by further barriers, especially the CAPEX bias in national regulatory frameworks for remuneration of network operators, the lack of appropriate and clear regulation for enabling and promoting alternative solutions, and technical or organisational aspects, as networks would typically be operated closer to their technical limits, requiring greater resources and knowledge from network operators. Network operators can be incentivised by benefit sharing mechanisms to implement such solutions. The study commissioned by ACER provides a

[1] In this report, costs of transactions related to the implementation of alternative solutions have been grouped into 3 categories: search and information costs, bargaining and decision costs, and policing and enforcement costs. This is the most common method to categorise transaction costs, while other methods also exist.

regulatory scheme that promotes more efficient and innovative solutions to address electricity network needs.[2]

Table 1 Cross-system solutions transaction summary

Cross-system solution	Stakeholders involved	Most relevant transactions	Impact of transaction costs on solution uptake
Digitalisation	• Device suppliers and manufacturers • Asset owners/operators • TSOs/DSOs • Flexibility service providers (FSPs)	• (Building and home energy management systems) operation • (Distributed energy resource management systems) dispatch and control of distributed energy resources	Low
Local flexibility and EU balancing platforms	• Platform/market operators • FSPs • TSOs/DSOs	• Platform qualification • Platform entry (for network operators and FSPs)	Low
Demand side flexibility and storage assets	• Asset owners/operators • FSPs • TSOs/DSOs • Platform/market operators	• Market exchange (tendering and trading) • Dispatch and control	Low-moderate
TSO/DSO cooperation	• TSOs/DSOs • National regulatory authorities (NRAs) • FSPs • Platform/market operators	• (Data exchange) data sharing authorisation • (Data exchange) data hub management • (Joint system operation) qualification	Moderate
Temporal/locational network tariffs	• TSOs/DSOs • NRAs • Grid users • Energy suppliers	• Transmitting signals to grid users • Reaction of grid users to tariffs	Low-high
Microgrids	• DSOs • Asset owners/operators • Microgrid owner/operator • Grid users	• Dispatch and control • Independent management contract with network operator (optional; in case microgrid operator is different)	Moderate-High
Flexible network access	• TSOs/DSOs • NRAs • Grid users	• Grid connection agreements	High

A number of examples of actual applications of cross-system solutions in the European Union (EU) and elsewhere are identified. We highlight two classes of solutions which are particularly recommended for consideration by regulators and network operators:

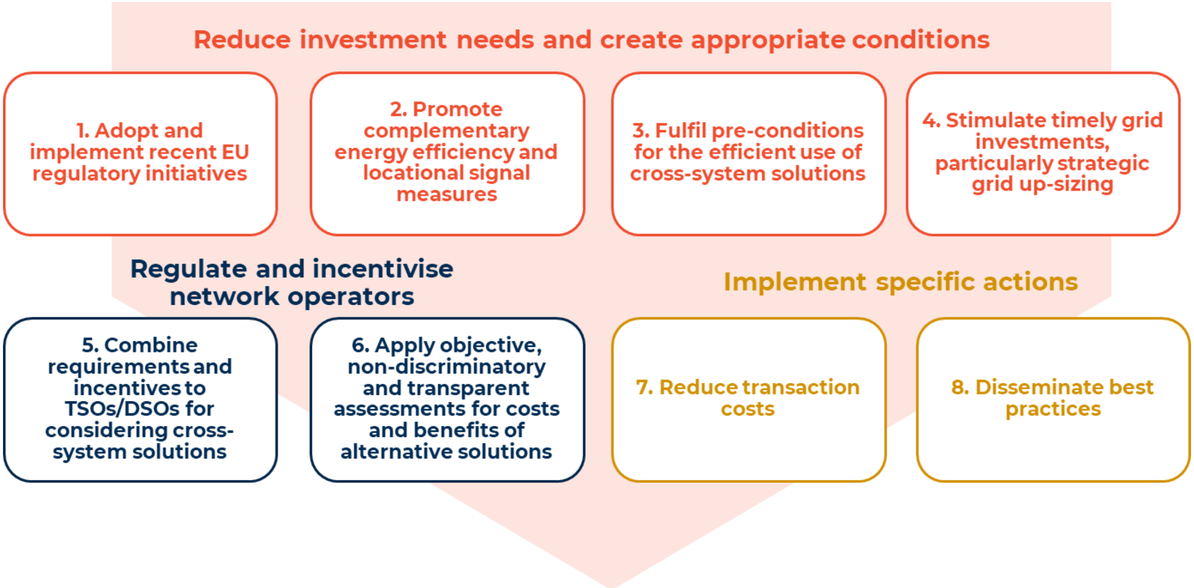
- **Low-hanging fruit**, namely solutions with a relatively fast implementation timeline, low CAPEX and low transaction costs, while providing substantial benefits ;
- **Enabling solutions related to digitalisation**, such as local flexibility platforms, advanced distribution management systems, distributed energy resource management systems or TSO/DSO cooperation related to data warehousing and exchange.

[2] ACER (2024), Benefit-based remuneration of efficient infrastructure investments.

Policy and regulatory recommendations

Chapter 5 details our recommendations for policymakers, regulators and network operators advancing the use of alternative solutions in general, as well as indicates specific considerations to be taken into account for the implementation of individual cross-system solutions. The recommendations are grouped in three main categories, as presented below.

Figure 4 Main recommendations of the study



Reduce investment needs and create appropriate conditions

1. **Adopt (where applicable) and implement recent EU regulatory initiatives**
   Authorities, network operators and relevant actors should properly implement the recent reform of the electricity market design, the upcoming rules on demand response and the requirements of the Energy Efficiency Directive for network operators, among others, which are expected to already significantly facilitate and accelerate the uptake of cross-system solutions in the EU.
   The dedicated ACER monitoring of barriers to demand response and other DERs as well as the new provision agreed in the electricity market reform requiring network operators to report on barriers to flexibility as part of the broader national flexibility assessments are welcome steps.

2. **Promote complementary energy efficiency and locational signal measures**
   NRAs could exchange information on regulatory practices used to incentivise TSOs/DSOs to reduce their grid losses and use this information to update their national regulation where appropriate. Policymakers could cooperate with the network operators when developing new policies to identify and promote measures which have the largest impact on reducing peak loads.
   Specific approaches for providing locational signals to grid users can be considered. Robust bidding zone reviews should take place according to existing regulation, but also locational connection tariffs, locational criteria in renewable energy or capacity mechanism auctions, and researching other ways to increase the spatial granularity of wholesale market price signals can be considered.

3. **Fulfil pre-conditions for the efficient use of cross-system solutions**
Policymakers and regulators should ensure pre-conditions are met to efficiently make use of the potential of cross-system solutions, particularly the development of enabling digitalisation-related solutions by mandating and properly remunerating network operators (or regulated third parties, e.g. those implementing and managing data hubs) to implement them. Moreover, some national authorities should reassess their decision not to opt for a large-scale roll out of low-voltage electricity smart meters. Member States that decided for a large-scale roll-out should closely monitor the actual progress and the efficient use of smart meters.

4. **Stimulate anticipatory grid investments, particularly strategic grid up-sizing**
The electricity market design reform requires tariff methodologies to reflect anticipatory investments[3] and to allow appropriate cost recovery. Approvals and permitting for anticipatory investments should be fast-tracked and streamlined to secure projects' go-ahead in advance of confirmed needs to enable demand's electrification and the timely connection of renewable electricity generation assets. For some Member States already facing significant structural congestion, this may be relevant to address forecasted network use growth towards 2040, while for other Member States with less severe congestion issues at the moment, anticipatory investments could help to connect additional assets in the shorter term.

Regulate and incentivise network operators

5. **Combine requirements and incentives to TSOs/DSOs for considering cross-system solutions**
National regulatory frameworks should (in line with the EU electricity market design) require the consideration of alternative options and authorise the recovery of the associated costs. Moreover, NRAs should consider various approaches (and if applicable their combination) to stimulate implementation of cross-system solutions, including TOTEX-based remuneration, benefit-sharing schemes, OPEX adders or bonus/malus-systems based on specific targets (congestion costs, curtailment costs, connection or construction times can be considered), among others.
NRAs also need to achieve a balance in the flexibility of the regulatory framework, avoiding overly prescriptive rules. A wide range of (sub-)solutions should thus be eligible, for example by employing functional specifications (rather than prescribing eligible solutions), enabling the implementation of both network-centric (such as GETs) and cross-system solutions.

6. **Apply objective, non-discriminatory and transparent assessments for costs and benefits of alternative solutions**
TSOs/DSOs should compare the costs and benefits of solutions and NRAs should critically review the proposed solutions. To avoid non-consistent approaches and underpin decisions with robust results, NRAs should establish objective and non-discriminatory methodologies to be used by DSOs/TSOs to undertake cost-benefit

[3] Anticipatory investments reinforce the grid based on anticipated potential future needs, which go beyond confirmed generation and demand needs

analyses (CBAs) for alternative solutions. NRAs could establish a minimum list of alternative solutions to be considered by the TSOs.

NRAs should develop rules regarding the disclosure of the results of CBAs for cross-system solutions and of the implemented projects' impacts. This concerns but is not limited to the procurement of flexibility through market-based or other approaches, but also the procedures for deciding on digitalisation, TSO/DSO cooperation, flexible connection agreements and other mechanisms

Implement specific actions

7. Reduce transaction costs

Policymakers and regulators should search for approaches to reduce transaction costs through the standardisation of products and processes, and digitalisation. Particular attention is required at the distribution level, where transaction costs can be higher due to the smaller size and greater number of assets deployed. NRAs can consider streamlined processes for authorising and remunerating distributed alternative solutions based on representative or standardised projects.

Transaction costs in the implementation of GETs (apart from appropriate oversight by NRAs) are limited. These transactions have very limited involvement with third-parties (such as grid users), greatly reducing transaction complexities and consequently transaction costs. Aside from these costs, the CAPEX and OPEX costs are in general outweighed by the benefits they provide to the system. TSOs and DSOs should hence be mandated by NRAs to implement GETs where appropriate and NRAs should establish adequate incentive mechanisms for technology adoption.

8. Disseminate good practices

While policy and regulatory measures will need to be tailored to the specific regulatory frameworks, compiling good practices and harmonising procedures could be highly useful. Such a repository could include information on criteria and processes for network operators' identification and CBA of alternative solutions as well as examples (with quantitative data) of implemented projects. The repository could also compile relevant studies on the topic.

To complement the compilation of good practices, regulators could commission the development of a handbook for promoting alternative solutions. The US-focused non-wires solutions implementation playbook[4] could serve as an example that should be adapted to the EU context.

[4] RMI (2018) The Non-wires Solutions Implementation Playbook - a Practical Guide for Regulators, Utilities, and Developers

1. Introduction

The European electricity system faces new challenges due to several ongoing developments. Electricity system operators need to deliver additional network capacity (domestic as well as cross-zonal), while managing volatility due to the increasing deployment of intermittent RES which increasingly require balancing and congestion management measures.

Transmission and distribution network reinforcements and extensions have constituted the classical approach to address many of these challenges. New grid investments are necessary to enable the energy transition and ensure affordable energy supply throughout Europe. With foreseen accelerated grid expansion, the current length of the European transmission network might see an increase 20% to 50% by 2040, for which the speed of TSO network buildout could increase by a factor of 11 to 27. On the distribution level, the increase in line length could be 20% to ~65%, by 2040, with a corresponding acceleration of network build-out by a factor of 1.4 to 4.6.[5]

However, given the long lead times and high investment required for upgrading and expanding the electricity network infrastructure, actors are paying increasing attention to alternative solutions like grid-enhancing technologies (GETs) and cross-system solutions. These aim to reduce the overall system costs and/or shorten implementation time to connect new grid users, either as temporary or permanent solutions.

Given the scale of the challenges, a comprehensive strategy, involving all available solutions is necessary (network expansion and reinforcement, GETs and cross-system solutions). This should allow to develop new network assets, optimise their utilisation, as well as leverage existing and future generation, storage and consumption/prosumption assets. The challenges at hand have already been highlighted by multiple ACER reports on the subject matter, including the 2023 Market Monitoring Report, as well as the Agency's 2023 Report on Investment Evaluation, Risk Assessment and Regulatory Incentives for Energy Network Projects.

However, there are still a lack of understanding regarding the costs, benefits as well as implementation scale and speed of the different alternative solutions than can be considered to address network challenges, and countries still struggle to achieve optimal use of existing assets despite the availability of mature solutions like GETs. Additionally, large-scale deployment of cross-system solutions remains limited due to the perceived deployment and often high transaction costs, as well as due to other barriers (for example of regulatory and technical nature). Understanding how certain actors have overcome these challenges can provide valuable insights that can help Member States to efficiently implement cross-system solutions.

1.1. Objectives, scope and approach of the study

The **objective of the study is to provide a better understanding on the solutions available within different sub-systems other than the network sub-system** to maximise the efficiency and effectiveness of investments and operations in electricity networks.. The focus is on characterising cross-system solutions (outside of the network sub-system)

[5] Compass Lexecon, CurrENT (2024): Prospects for innovative power grid technologies

addressing the lack of sufficient network capacity and the need for procurement of flexibility services, identifying barriers and good practices to their upscaling (particularly related to high transaction costs), and proposing associated recommendations to stimulate their deployment.

The **scope of the study** includes alternative solutions from the different electricity subsystems (i.e., generation, storage, and consumption/prosumption), while also, to a limited extent, considering solutions that can be provided by associated energy systems, such as the methane, heat and hydrogen systems. The study focuses on the electricity system in the EU, and also includes information on relevant solutions in other liberalised electricity markets such as Norway, the UK, the US, Australia and Switzerland.

In this study we inherently take the perspective of the electricity system when looking at other energy vectors. For this reason, the **study considers flexibility from other systems implicitly** (such as the gas/hydrogen or heat ones) in the selected solutions which interface with those systems. From this perspective, energy vectors other than electricity are relevant mainly via their impact on the electricity grid, for example through demand response solutions (which provide an interface between the electricity and other systems through e.g. hybrid heat pumps or flexible operation of electrolysers). Flexibility provision from (combined heat-and-)power generation based on renewable and low-carbon gases is another example of cross-system solutions interfacing with the gas/hydrogen system. Developing clean gas/hydrogen and heat systems would also reduce the electricity investment needs in the first place, but this is out of scope of the present study.

The **study's approach** is as follows:

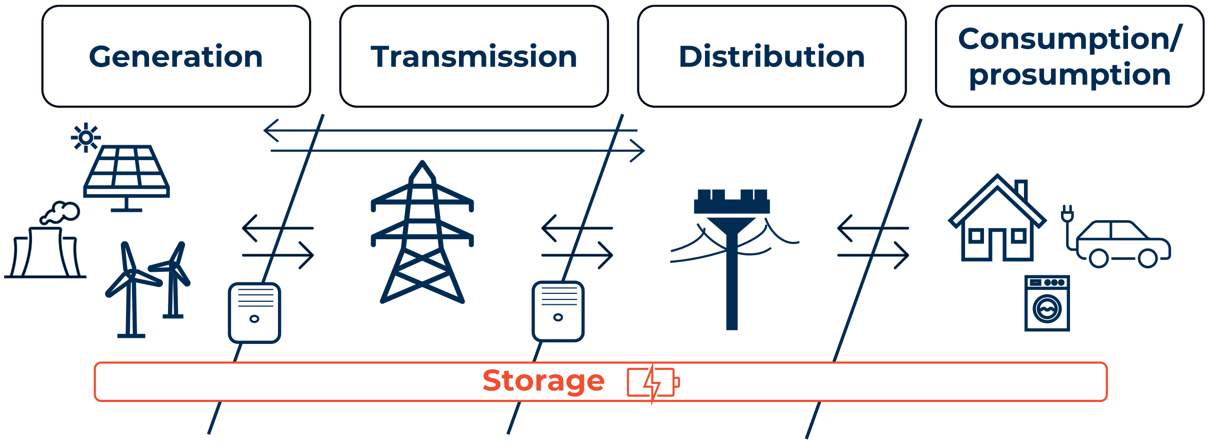
1. First, we define a short-list of challenges and associated solutions for unlocking the full potential of the electricity system of systems, based on literature review and consultations with ACER;
2. Secondly, we draft an overview of possible transactions and related costs for each solution, and assess the barriers (mainly focusing on transaction costs) that hinder large-scale implementation of alternative (or "new") solutions, with stakeholder consultations conducted on a per-need basis. In parallel, we also analyse the impact of SOs and NRAs on transactions and related costs;
3. Third, we review options for reducing transaction costs and for improving the effectiveness of alternative solutions for addressing challenges in the electricity networks. and identify some frontrunners in reducing transaction costs, in different geographies.

The project further verified the draft results of the analysis in a workshop with stakeholders, who provided valuable feedback on the study results which were incorporated in this final report.

1.2. Solution terminology employed in this study

To understand the different needs of the electricity system and the complex socio-technical challenges described in this study, distinguishing between sub-systems is useful to identify challenges and solutions within each of them. Figure 5 presents the electricity sub-systems. The electricity sub-systems in the figure corresponds to the generation, transmission, distribution, storage and end-use stages of the electricity value chain.

Figure 5 The electricity system and its sub-systems



The literature does not provide a term which fully captures the cross-system solutions covered in this study. Various interrelated terms are employed:

- The term "Non-wire alternatives or solutions" is frequently used, and refers to solutions other than network expansion. However, some experts consider non-wire solutions to comprise only distributed energy resources, DERs (which is sometimes considered to comprise also energy efficiency measures).[6] ACER employs a broader definition in its 2023 Market Monitoring Report on demand response and other DERs[7], indicating non-wire alternatives include "market-based re-dispatching, non-firm connection agreements or interruptible tariffs, dynamic line rating, among others".[8]
- "Smart options" is a term used by the Swiss Federal Office of Energy, and includes smart grid solutions managed by DSOs (including curtailment of distributed generation), and smart market solutions such as procurement of services against financial payment.[9]
- "Non-conventional grid expansion" is employed by the EUniversal project, and includes grid-enhancing solutions developed by network operators as well as cross-system solutions.[10]
- Grid-enhancing technologies (GETs), which constitute another important subset of alternative solutions to network expansion, are defined by the US Department of Energy as solutions that maximize the transmission or distribution of electricity across the existing system through a family of technologies that include sensors, power flow control devices, and analytical tools.

GETs are frequently considered together with cross-system solutions. There are a number of reasons for this:

- Grid-enhancing technologies and cross-systems solutions frequently face similar regulatory barriers for their deployment, particularly those related to the insufficient

[6] RMI (2018) The Non-wires Solutions Implementation Playbook - a Practical Guide for Regulators, Utilities, and Developers
[7] In this study DERs include demand response, storage and generation assets connected at the distribution level. See ACER (2023) Demand response and other distributed energy resources: what barriers are holding them back? 2023 Market Monitoring Report
[8] ACER (2023) Market Monitoring Report 2023 - Demand response and other distributed energy resources: what barriers are holding them back?
[9] Swiss Federal Office of Energy (2017) Smart Planning - Optimal Planning of Future Distribution Grids Under Consideration of Smart Grids and Smart Markets
[10] EUniversal (2021) Deliverable: D1.3 Challenges and opportunities for electricity grids and markets

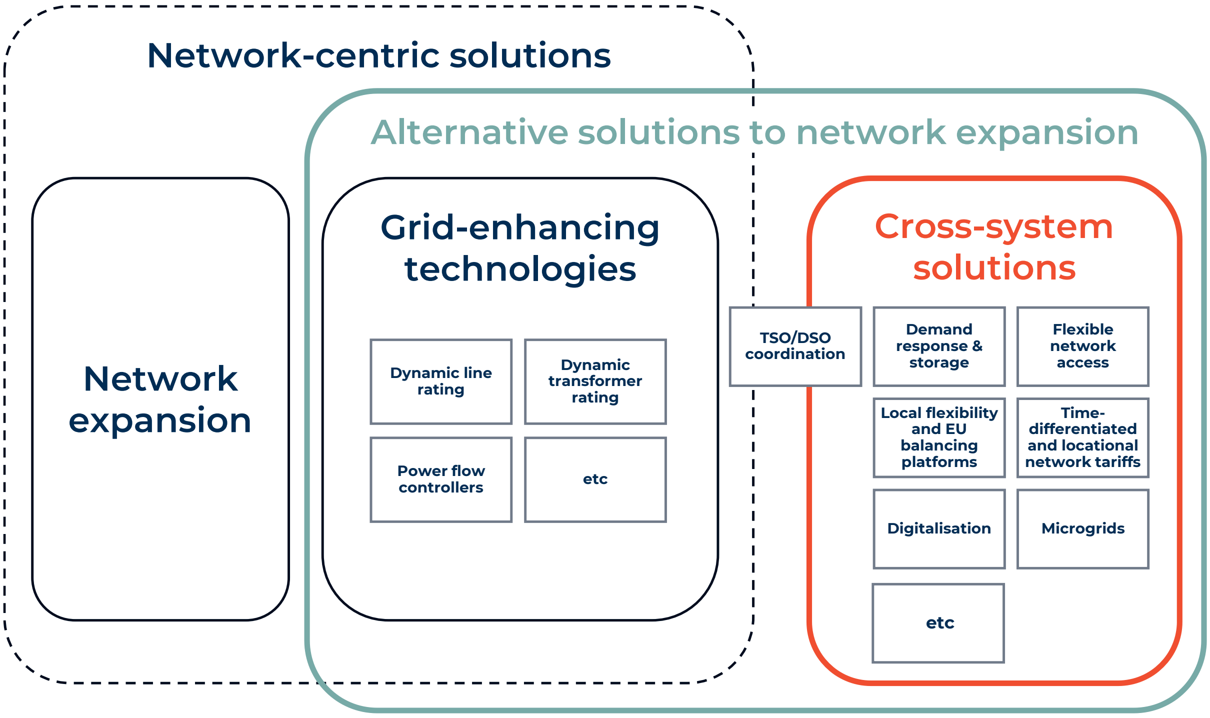
consideration of alternative solutions by network operators due to e.g. CAPEX-biased remuneration frameworks;

- Grid-enhancing technologies and cross-systems solutions can often be employed (and combined) to address similar network challenges. Network planning and system operation should choose the least-cost solutions which adequately address the identified system challenges and allow to meet quality requirements. Hence, ideally GETs and cross-system solutions should be considered (and incentivised) equally.

The focus of this report is on cross-system solutions within the electricity sector (with interactions with other energy systems being considered through the relevant interfaces). Cross-system solutions are interpreted in this context as solutions that can be deployed or interact with stages of the electricity value chain other than transmission and distribution to address challenges faced by TSOs and/or DSOs. This includes flexible assets, or technologies and services that enable collecting and monitoring data, communication technologies such as smart meters, sensors, advanced control systems and market mechanisms, as well as structures that govern electricity transactions, such as pricing, trading, and market operations. Solutions which are deployed within the transmission or distribution sub-systems are called network-centric solutions, and include both network expansion as well as GETs.

Figure 6 illustrates how network-centric and alternative solutions are interrelated. The figure includes examples of GETs and cross-system solutions discussed in this study – however, there are many other examples of alternative solutions which are deployed on a commercial basis or are currently under development. The cross-system solutions we identify and GETs are all grouped as alternative solutions to network expansion.

Figure 6 Network-centric and cross-system solutions to address network challenges

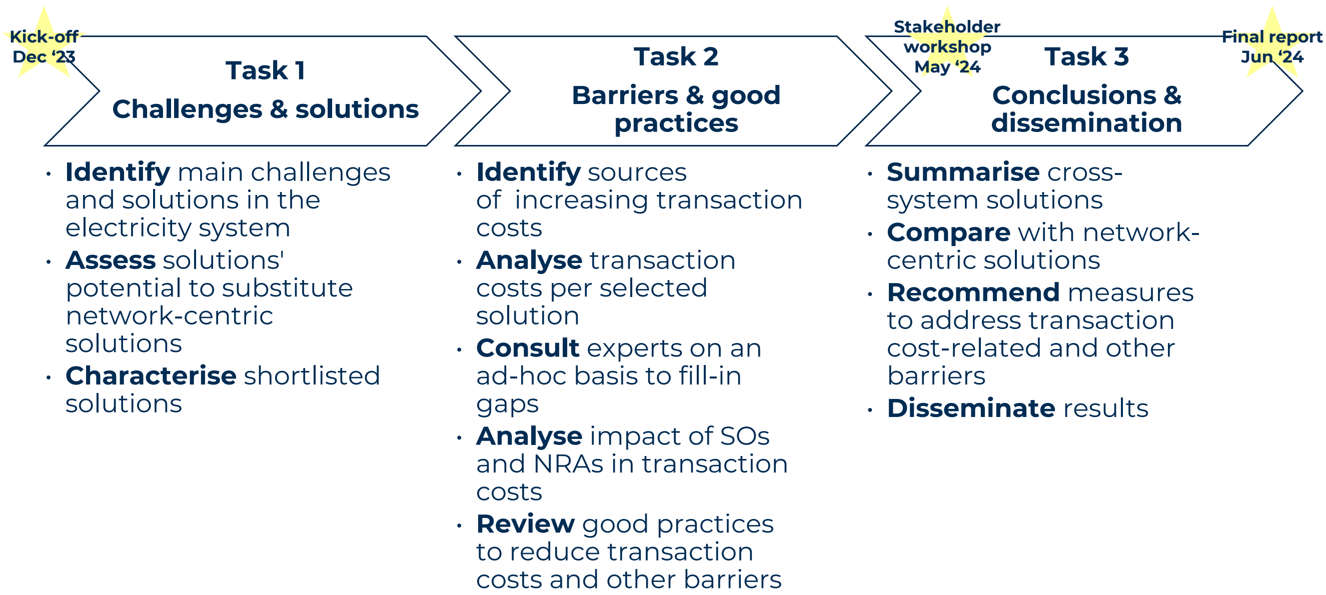


1.3. Methodology of the study

Figure 7 summarises the methodology for this study, which was broken down in three main tasks: 1) characterising the network challenges and the associated cross-system solutions, 2) studying the barriers (including transaction costs) and good practices for developing the solutions, and 3) summarising the analysis, providing recommendations and disseminating the study results.

The study main source of information is the literature, which was complemented by requests for information to the Member States' NRAs and discussions with stakeholders (bilaterally and through a stakeholder workshop organised in May 2024.

Figure 7 Methodology for this study



1.4. Limitations of this study

The below aspects are considered as limitations of this study:

Quantitative data gaps on costs and benefits:

There is a lack of sufficient quantitative data regarding the actual costs and benefits of cross-system solutions, mainly because of the infancy of the topic from a system perspective, the resulting lack of studies carried out so far, the incipient level of deployment by many system operators, and insufficient transparency of conducted cost-benefit assessments. Without robust data, it is difficult to evaluate the economic feasibility and effectiveness of different approaches. The comparison and ranking of various solutions' suitability to address the different network challenges is also impacted by the lack of data.

Number of cross-system solutions selected

After an initial screening of a longlist of existing cross-system solutions, the project team has in agreement with ACER shortlisted a final set of seven solutions that were analysed in the study. This selection is not exhaustive - there are other solutions that are not included in this shortlist, because of the resources available for the study, overlaps with the shortlisted solutions, or the lack of data on their actual implementation and benefits.

1.5. Structure of this report

The remainder of this report is structured as follows:

- **Chapter 2 presents the network challenges** which can be addressed by cross-system solutions, indicating to which level they apply (e.g. transmission and/or distribution networks) and the challenges' impact;
- **Chapter 3, characterises the cross-system solutions, their contributions and costs and benefits**. This chapter also presents the main network-centric solutions (particularly network expansion and GETs), which constitute the basis for comparison with cross-system solutions;
- **Chapter 4 assesses the identified cross-system solutions' transaction costs and scalability, and identifies other barriers** for their uptake, such as regulatory, financial, technical, organisational and social barriers, as well as discusses the role of NRAs and system operators;
- **Chapter 5 provides an overview of the considered cross-system solutions**, highlights interesting use cases and good practices, and provides policy and regulatory recommendations;
- **Annex I (chapter 6) presents cross-system solution fiches** characterising each considered solution in detail, including with examples of application and data on costs and benefits (when available).

2. Challenges faced by electricity networks arising from the clean energy transition

This chapter details the main challenges for network operators (as summarized in Table 2). The evolution of Europe's electricity sector is characterised by a major shift from dispatchable centralized power generation and manageable demand growth to mainly variable decentralized renewable energy-based electricity production, accelerated demand growth and changing demand profiles.

This transition presents huge challenges for network operators, such as the need for modernization and expansion of their grid to accommodate this growing demand and timely connect new power generation assets. Network operators have also to cope with increased grid congestion and require more ancillary services for their balancing and other operational activities. Significant grid investments are needed but cannot be timely realised, notwithstanding the different initiatives taken by EU authorities to facilitate grid investments.[11]

Table 2 Characteristics and impact of electricity network challenges

Category	Challenge	Level	Impact
System needs	Identification of the energy system needs	Transmission and distribution level	Hinders the accurate reinforcement of the grids and optimal use of available resources
Investment needs	Significant investment needs to reinforce the network	Predominately at distribution level; also at transmission level	Slows down the deployment of DERs and uptake of EVs
	Limited availability of private and public funding	Predominately at distribution level; also at transmission level	Slows down investments, increases cost of capital
Grid capacity	Limited grid connection capacity	Domestic transmission & distribution grid elements	Impedes the connection of new users or increased offtake/injection of existing users
	Limited cross-zonal capacity & low utilisation	Cross-zonal and domestic transmission network elements	Impedes cross-border trade or requires costly CM measures
	Increasing congestion in networks	Cross-zonal and domestic transmission or distribution network elements	Requires costly post-market clearing management measures
Balancing and non-frequency ancillary services	Increasing penetration of intermittent RES and electrification of end-uses	Transmission level	Increases need for residual balancing by network operators
	Ramp-up/down limitations of dispatchable RES-based electricity generation	Distribution level	Jeopardizes grid stability
	Complex coordination between actors	Transmission and distribution level	Impedes the timely activation of DERs in balancing and wholesale markets

This overview does not include other important challenges that are not directly related to the design of electricity markets and the regulation of network operators, such as the shortage of skilled labour, supply chain bottlenecks for network components, and complex permitting procedures for grid investments. These issues are currently being tackled through policy measures at the EU and national levels.

[11] European Commission (2023) Grids, the missing link - An EU Action Plan for Grids

Electricity system adequacy challenges are also not specifically discussed, as ensuring resource adequacy is primarily a policymaker's responsibility, although network operators play a role in resource adequacy assessments and sometimes the implementation of capacity mechanisms.

Higher complexity to identify the electricity system needs

Properly identifying and monitoring the energy system needs at national and EU level constitutes the first important challenge. Considering the uncertainty regarding non-dispatchable renewable electricity generation and demand growth, as well as the aging grid infrastructure, this has proven to be a difficult exercise, but investment planning processes for both electricity transmission and distribution networks are advancing significantly. Various studies are conducted to identify the capacity needs and the areas that require reinforcement of the grids, notably ENTSO-E's identification of system needs assessment, undertaken as part of the 2024 Ten Year Network Development Plan (TYNDP) cycle,[12] and the DSO network development plans which are now required for all DSOs.[13] Additionally, several grid capacity maps have recently been developed at national or regional level offering valuable insights about the need for additional domestic and interconnection capacity.[14,15]

Significant investment needs in electricity networks

Significant investments in cross-border transmission capacity are currently being realised and planned by electricity TSOs, with additional investment needs identified.[16] Significant investments are also required to reinforce and extend domestic electricity networks (at the transmission and distribution levels) to accommodate the further growth foreseen in the deployment of distributed wind and solar PV-based electricity generation, as well as the uptake of heat pumps, EVs and other power appliances and equipment.

Distribution grids represent a considerable share of the overall investment needs. The European Commission estimates that between 2020 and 2030, in total €584 billion will be needed in electricity grid investments in order to achieve the goals of the REPowerEU Plan[17]; 65-72% of these investments would serve to enhance distribution grids specifically. The impact assessment supporting the European Commission's proposed 90% target for greenhouse gases emission reduction by 2040[18] also points to significant investment needs. More specifically it estimates that upscaling and upgrading the transmission and distribution networks would require average annual investments in the power grid of €85 billion for the period 2031 to 2050.

The massive investment needs in electricity networks will require additional financing sources. Historically, grid operators could to a large extent finance their investments by using tariff revenues. The significantly larger investment volumes means network operators will to an increasing extent have to attract additional financial resources such as equity capital, private loans (including green bonds), and public (soft) loans or grants. The solutions considered in this study can to some extent reduce the investment and related

[12] ENTSO-E (2023) System Needs: Study Opportunities for a more efficient European power system in 2030 and 2040
[13] With the possibility for Member States exempting smaller DSOs or those operating isolated systems.
[14] https://www.elia.be/en/customers/connection/grid-hosting-capacity
[15] https://netztransparenz.tennet.eu/electricity-market/connecting-to-the-dutch-high-voltage-grid/grid-capacity-map/
[16] ENTSO-E (2023) System Needs: Study Opportunities for a more efficient European power system in 2030 and 2040
[17] Commission Staff Working Document (2022). Implementing the REPowerEU Action Plan: Investment Needs, Hydrogen Accelerator and Achieving the Bio-methane Targets.
[18] European Commission (2024) Europe's 2040 climate target and path to climate neutrality by 2050 building a sustainable, just and prosperous society

funding needs. It is also noted that grid operators' high investment challenges are compounded by high inflation rates and rising equipment and construction costs.[19]

Increasing grid congestion and insufficient grid capacity for new connections

The accelerated deployment of decentralised renewable energy sources, mainly connected to distribution grids, has led to increasing capacity constraints on electricity grids. DSOs are facing higher congestion due to the rising need to connect distributed energy resources (DERs) and the gradual deployment of heat pumps and electric vehicles,[20] with the limited grid capacity and long lead times for expansion force DSOs to prioritize or reject connection requests.[21]

In 2022, the amount of congestion income reported in the EU has increased by over a factor of three compared to the previous year. The need for costly congestion management measures is on the rise too. There has been a steady increase in the activation of corrective measures involving renewable electricity curtailment, with their proportion compared to the total renewable energy generation growing from 3.3% in 2020 to 7.5% in 2021 and further to 17.1% in 2022, marking a significant escalation compared to previous years.[22] Thie need for redispatch is expected to increase significantly in the future, even in scenarios of significant network expansion.[23]

Furthermore, while a high availability of existing interconnection capacity for market purposes between bidding zones would alleviate the pressure in the grids and provide further flexibility, the latest ACER report[24] finds that the effectively available cross-zonal transmission capacity remains in most EU borders below the 70% target. This limited exchange capacity made available to the market exacerbates domestic congestion, hindering the efficient integration of renewable energy based electricity and overall competition in and affordability of the EU electricity system.

It is important to understand the differences between the various congestion-related specific challenges. They can differentiated according to the following aspects:

- The "limited grid connection capacity" challenge is driven by structural congestion (present or forecasted) of the domestic transmission (within a price zone) or of a distribution system. This challenge primarily impedes the connection of new grid users or increased offtake/injection of existing users.
- The "limited cross-zonal capacity & low utilisation" challenge is driven by the limited capacity of cross-zonal interconnectors or the structural congestion of critical network elements (cross-border or domestic) which limits the cross-zonal capacity which can be made available to the market, for example due to loop flows. This challenge primarily impedes cross-zonal trade (including of resources to meet ancillary service needs), or requires costly congestion management measures
- The "increasing congestion in networks" challenge is of course related to all congestion-related challenges. But here specifically it refers to congestion (structural or not) which increasingly requires (costly) post-market clearing

[19] Scope Ratings (2023) Europe's grid operators brace for capex surge Rising regulated tariffs on enlarged RAB and countermeasures provide longer-term relief
[20] DSO Entity (2023) DSOs Fit for 55 Challenges, practices and lessons learnt on connecting renewables to the grid
[21] Ibid.
[22] ACER (2023) Progress of EU electricity wholesale market integration - 2023 MMR
[23] JRC (2024) Redispatch and Congestion Management
[24] ACER (2023) Cross-zonal capacities and the 70% margin available for cross-zonal electricity trade (MACZT) - 2023 Market Monitoring Report

congestion management measures in order to make dispatch schedules feasible, such as curative redispatch.

Increasing needs for balancing and non-frequency ancillary services

With the growing penetration of intermittent renewable power generation facilities, balancing responsible parties (BRPs, for their portfolios) and TSOs (for residual system imbalances) are facing specific challenges. As solar and wind energy exhibit generation profiles which cannot be fully predicted in the day-ahead timeframe, deviations must be monitored closer to real-time and appropriate measures have to be taken to ensure the balancing of the BRP portfolios and the overall system, at the intra-day and balancing timeframes.

The fact that current dispatchable renewable energy based electricity generation (e.g. hydropower and biomass-based power plants) has in general lower ramp-up/down capabilities than fossil-based power plants, enhances the balancing challenges faced by BRPs and TSOs, although power generation based on renewable and low-carbon gases could help address this issue. Furthermore, as most DER assets are connected to DSO grids, DSOs must increasingly also intervene to prevent and solve other local issues in order to ensure a reliable and stable grid functioning, such as in the case of voltage control.

Another challenge identified is the increased complexity and need for coordination between different actors. As BRPs now manage a more diverse portfolio of assets, encompassing both dispatchable and non-dispatchable generation plants, storage capacity and increasingly also demand response, they need to interact with system operators and with other market parties (including aggregators). TSOs are responsible for system-wide balancing, congestion management and voltage control at transmission level as well as for coordination with power exchanges, while DSOs are responsible for congestion management and voltage control within their grids. Hence, TSOs must coordinate with DSOs when resources such as DERs are activated in balancing and wholesale markets.[25] In this context, two specific challenges that are encountered and identified across literature are i) the aggregation of small-size DERs (and demand response) by independent service providers and ii) cost reduction of the ancillary services markets.[26]

[25] Florence School of Regulation (2022) Distributed energy resources and electricity balancing: visions for future organisation
[26] Falabretti D, Gulotta F, Spinelli L. Participation of Aggregated DERs to the Ancillary Services Market: A Monte Carlo Simulation-Based Heuristic Greedy-Indexing Model. Energies. 2022; 15(3):1037. https://doi.org/10.3390/en15031037

3. Cross-system solutions to address network challenges

This chapter aims to characterise the cross-system solutions regarding their potential contribution to address network challenges at the transmission and/or distribution level, their implementation timeline and CAPEX and OPEX levels. Quantitative data on costs and benefits is presented where identified. Network expansion is also discussed as it constitutes the counterfactual for assessing the costs and benefits of cross-system solutions, and grid-enhancing technologies are also presented given they also constitute an appropriate alternative to network expansion. The chapter is organised as follows:

- Section 3.1 presents the network expansion, GET and standard solutions to the network challenges;
- Section 3.2 introduces the cross-system solutions;
- Section 3.3 analyses the cross-system solutions and GET contributions to address network challenges;
- Section 3.4 presents data on costs and benefits of cross-system solutions as well as qualitatively assess their potential speed of implementation, CAPEX, OPEX and benefit levels.

3.1. Network-centric network solutions

This section characterizes the classical solutions deployed by network operators for addressing the network challenges identified in the previous chapter. The characterization of these solutions aims to provide a baseline for the comparison with the alternative, cross-system solutions, which are discussed in section 3.2.

The reference network solutions considered in this analysis are network expansion (and the use of grid-enhancing technologies (GETs).

3.1.1. Network expansion investment costs

Network expansion involves investments in various assets, including overhead, underground and submarine lines (AC and DC), substations (onshore and offshore), and transformers and HVDC converters, as well as supporting equipment and ICT systems. It includes new lines/transformers as well as reinforcements of existing line infrastructure. Given the different categories of assets, the fact that costs are specific to each project, and that there are multiple ways for comparing network expansion investment costs (i.e. relative to line capacity and length, or the additional renewable energy capacity or peak load it allows to integrate), it is not straightforward to define a comparison metric. We present next average necessary investment per line length, and per MW of distributed renewable power integrated.

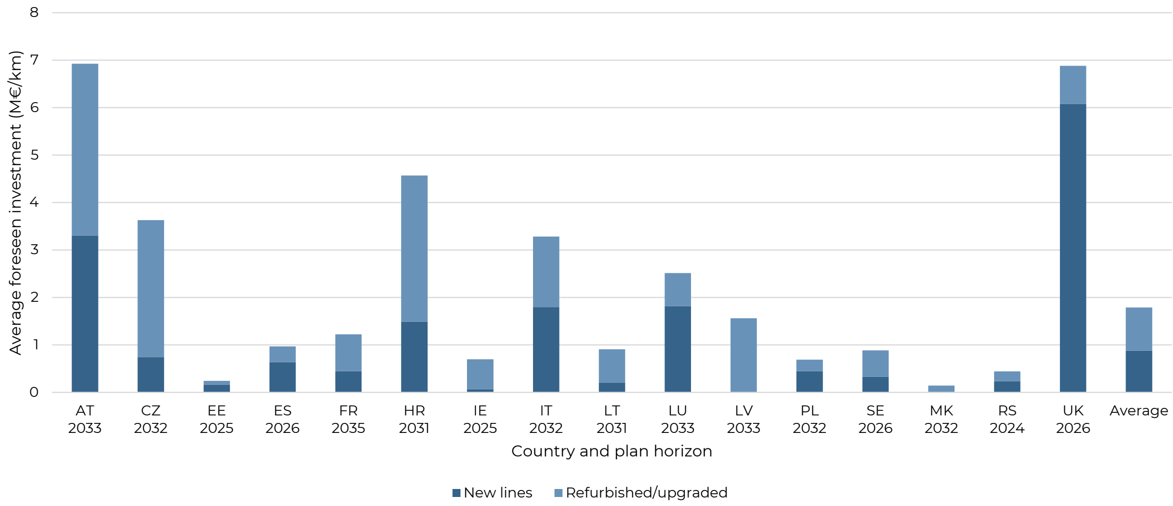
In a recent report on grid investments, Ember indicates[27] that TSOs in the EU, UK, CH, NO and Western Balkans plan to spend 30 B€ annually in the coming years on transmission grid investments. This is close to current expenditure levels - 28 B€ for transmission and 35 B€ for distribution investments in 2022 (although it must be noted that this is higher than

[27] https://ember-climate.org/insights/research/putting-the-mission-in-transmission-grids-for-europes-energy-transition/#supporting-material

historical levels already). According to the TSOs, approximately 30 000km of existing grid lines should be modernised, along with the building of 34 100km of new lines (see Figure 8)[28]. Ember estimates that the total length of transmission lines[29] will grow by 3.8% between 2023-2026, and by further 8.1% between 2027-2030. Ember's evaluation of grid investments planned by the TSOs against the latest renewable energy targets and recent solar and wind energy projects outlooks concludes that the planned transmission grid developments are in several countries insufficient to accommodate the RES uptake that is necessary to achieve the policy targets.

Still, **the data suggests an average investment of 1.8 M€/km for the countries where data was available** (EU and other European countries), as shown in the figure below. However, there is significant variation between average investment levels in M€/km between countries, these investment values also include investments in substations and other investment items, and the considered period is not the same for all countries.

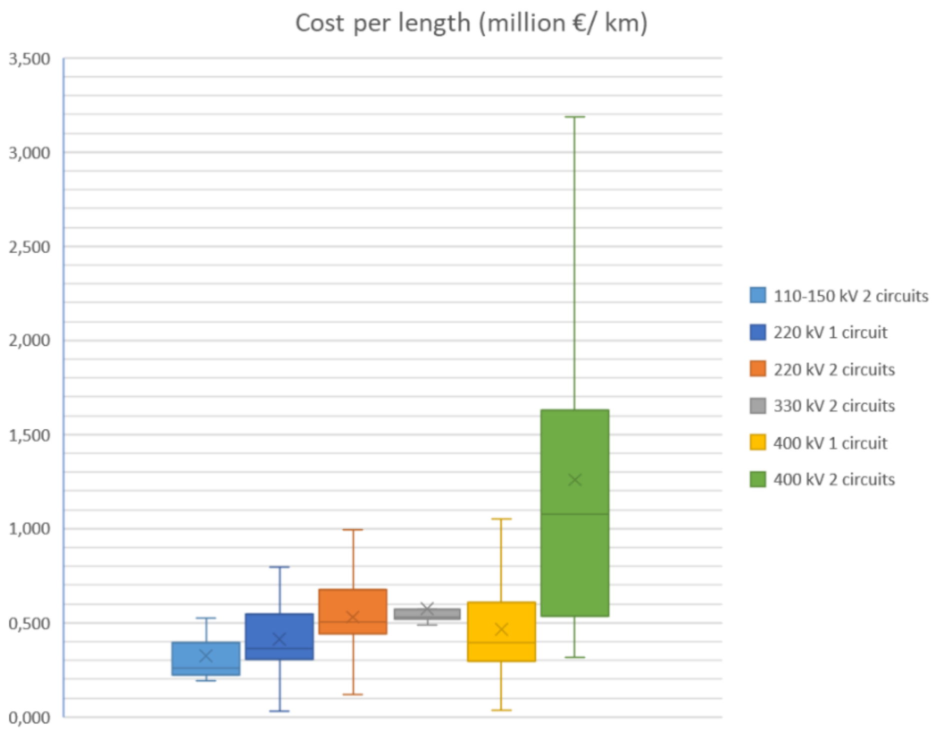
Figure 8 Average unit investments foreseen in TSO plans (own elaboration based on Ember data)



In a study for ACER, PwC[30] provides an overview of reference unit costs for the main electricity transmission infrastructure assets. While many categories are assessed, the costs for overhead lines provide a relevant reference for electricity transmission costs in general. As can be seen from the figure below, there is significant variation in unit costs depending on voltage levels and number of circuits, **with overhead lines' unit investment costs (within the standard deviation) varying from under 0.3 M€/km to over 1.5 M€/km.**

[28] From the grid plans examined in the Ember study which indicate the proportion of newly build vs. modernized networks
[29] Based on the 25 plans with sufficient data reviewed
[30] PwC (2023) Unit Investment Cost Indicators – Project Support to ACER

Figure 9 Unit investment costs for overhead lines[31]

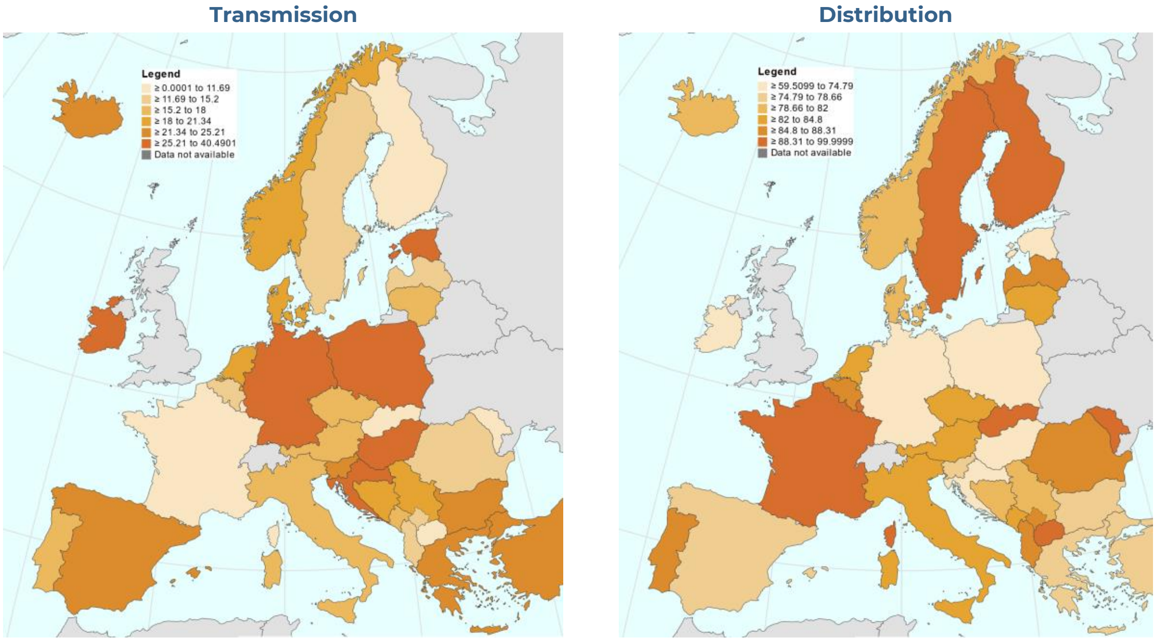


A study commissioned by Eurelectric in 2021 estimates that the EU27+UK's distribution grids will need 375-425 B€ in investments until 2030 to accommodate digital, decarbonised and decentralised energy solutions, representing 34-39 B€ annually.[32] 95-115 B€ of this would be for directly enabling end-use electrification. 85-95 B€ would be required for the integration of 360 GW of distributed renewables, or **0.25 M€ per MW of distributed renewables on average.**

Network expansion might further increase network tariffs, and thereby impact household electricity prices as well as industrial competitiveness. In several Member States, network costs are already strongly increasing, due to higher investment depreciation levels: for example in the Netherlands, grid tariffs for residential consumers has risen from 85€/MWh in 2023 to 105 €/MWh in 2024[33], with increases alike observed for small and large professional consumer profiles too. Similar tariff increases have occurred in Belgium and Germany. For transmission tariffs, the increases are even much higher. This is clear from Eurostat data[34] for 2023, where the share of network costs (transmission and distribution) for electricity in the EU27 shows (see Figure 10) that for households, the cost of network use is very high in some countries, particularly in Hungary, Ireland, Estonia and Germany (ranging between 32 and 40% of the overall electricity bill). For non-household users this share can increase to 52-59% (Ireland, Italy).

[31] PwC (2023) Unit Investment Cost Indicators – Project Support to ACER
[32] Eurelectric (2021) Connecting the dots: Distribution grid investment to power the energy transition
[33] Pages 22-26 of PwC for CREG (2024) - F20240515EN.pdf (creg.be)
[34] Eurostat - Share for transmission and distribution in the network cost for gas and electricity - annual data nrg_pc_206

Figure 10 Share (%) of transmission and distribution in the electricity cost of households, 2023[35]



3.1.2. Grid-enhancing technologies (GETs) as alternative network-centric solution

Grid-enhancing technologies allow to "maximize the transmission or distribution of electricity across the existing system through a family of technologies that include sensors, power flow control devices, and analytical tools".[36] The main benefits of GETs are threefold[37]:

1. They allow for a better use of existing grid infrastructure;
2. They allow for faster deployment of grid capacity at system level, accelerating grid expansion at both the transmission and distribution level;
3. They reduce the need for grid investments.

Main examples of GETs comprise:

- **Dynamic and ambient line rating (DLR/ALR)**: DLR comprises hardware and software used to monitor line conditions and calculate thermal limits based on monitored data and weather forecasts in order to operate lines closer to real thermal limits, which can often be significantly higher than nominal limits . ALR is a simpler and cheaper alternative to DLR, where adjusted ratings (based on temperature and other weather conditions) allow more power to flow over power lines than static/seasonal line ratings,[38] but without the real-time monitoring of line conditions which characterises DLR;
- **Dynamic transformer rating**: similar to DLR, dynamic transformer rating comprises hardware and software used to calculate thermal limits of transformers based on monitored data in order to operate the transformer closer to actual limits, maintaining a balance between higher utilisation and the impacts on the asset lifetime;

[35] https://ec.europa.eu/eurostat/databrowser/view/nrg_pc_206/default/bar?lang=en&category=nrg.nrg_price.nrg_pc
[36] US Department of Energy (2022) Grid-Enhancing Technologies: A Case Study on Ratepayer Impact
[37] CurrENT and Compass Lexecon (2024): Prospects for innovative grid technologies
[38] https://www.utilitydive.com/news/ferc-line-ratings-transmission-gas-pipelines/611716/

- **Power flow controllers (PFCs)**: hardware such as phase shifting transformers or software such as topology control, used to reroute power away from lines which are congested or close to congestion, in order to increase the overall utilisation of the system.[39]
- **High-temperature superconductor (HTS) cables:** cables made from special materials which can carry five times the current of conventional cables. They are cooled down to extremely low temperatures, thereby activating the 'superconductivity phenomenon'.[40]
- **Digital Twin (DT) platforms:** digital representations of physical energy assets (e.g. transformer station or other grid technology) via modelling, mirroring and capturing the performance and operational behaviours of the modelled asset.[41]

Some solutions and applications can be considered 'low regret' options as they have modular attributions, or are moveable or can be flexibly deployed, like modular power flow control devices. The various technological solutions at the disposal of TSOs are presented in ENTSO-E's Technopedia; this overview may however not reflect the latest technological developments.

The reasons for deploying GETs can be similar to those for implementing cross-system solutions: **GETs and cross-system solutions can often be commissioned more quickly than new line investments, and entail much lower cost levels.** Another major difference is that GETs can be deployed unilaterally by individual network operators, and thus require much less coordination with stakeholders, while cross-system solutions are either deployed by market parties or at least involve the cooperation of multiple network operators, making their implementation more complex.

While GETs are simpler to implement due to their shorter lead time and lower cost than network expansion projects, **GETs typically involve larger operational costs by network operators** (e.g. larger headcount) compared to traditional network expansion and the benefits of individual GET projects are smaller - hence multiple projects are generally needed to reach the total societal benefits of a new transmission line. Furthermore, a study commissioned by CurrENT in 2021[42] concluded that these technologies bring complementary benefits to investments in grid expansion, rather than being substitutive to each other. This study and the accompanying scenario demonstrate that utilizing GETs can decrease congestion and redispatching expenses by over 90%, as well as reduce congestion-related curtailment of renewable energy injection by 3 TWh in 2030.

A new study on the topic further estimates that installing innovative grid technologies could result in a 20% to 40% overall capacity improvement for the wider network, and reduce the need for network buildout by approximately 35% by 2040 (corresponding to overall gross savings of 700 B€ in Europe that would be otherwise spent on conventional expansion costs). The costs of deployment of these technologies (which are OPEX-heavy) are however not considered in this figure[43].

[39] US Department of Energy (2022) Grid-Enhancing Technologies: A Case Study on Ratepayer Impact
[40] ENTSO-E. High Temperature Superconductor (HTS) Cables
[41] ENTSO-E. Digital Twin
[42] The Benefits of Innovative Grid Technologies (currenteurope.eu). The study has focused on Central Western Europe.
[43] CurrENT and Compass Lexecon (2024): Prospects for innovative grid technologies

While GETS are mainly associated with transmission networks, they **can also be deployed for distribution networks**, for example DLR[44], power flow controllers and digital twins. In some cases, distribution networks may even offer a greater potential for deployment of GETs, such as in the case of topology control software. Based on real-world deployment issues of DSOs, CurrENT put together a guiding document[45] with recommendations to support DSOs in applying these GETs, including those listed above, given limited DSO resources to consider the specificities of GETs. Many of these GETs are promising for managing system needs in distribution grids, but specific tendering and procurement practices need to be in place for their deployment.

The report also emphasizes that when conducting CBAs for different technologies, it is very important to consider the lead time for deploying the solutions and the construction and finance costs, in order to ensure that the net present value (NPV) calculations properly reflect the solutions' actual costs and benefits. Incorrect assumptions of overnight costs for calculating NPVs can affect GETs and other solutions disadvantageously, even though they could be implemented in the short term.

A great number of case studies[46] have been presented in a 2022 study based on the deployment and simulation of GETs (DLR and PFCs), to determine their outcomes and costs, where comparable, with traditional investments. One of them concluded that the combined implementation of GETs would allow for an increase of 2,670 MW of integrated RES without additional transmission line upgrades, and would lower curtailment needs of existing wind energy generation by 76,000 MWh/yr in Kansas and Oklahoma. The annual savings on electricity production costs in this case were estimated at $175 million (EUR 163 million). Another deployment case has allowed to avoid EUR 24 million compared to the replacement of a line. [47]

More recent case studies presented by CurrENT[48] state that grid technologies including DLR, advanced power flow controls and superconductors can increase the capacity on a certain line by up to 170%. In the US, GETs are expected to enable the doubling of the amount of renewables fed in into the electricity network in the next five years[49]. Ambient line ratings, for example, are already used by US utilities, to account for near-term changes in temperature and solar heating values, and to measure capacity on transmission lines[50], along with DLR solutions.

According to a 2022 assessment by SmartEN[51], despite their benefits being recognised by the regulatory and TSO community in the EU, hardly any GETs are mentioned in Member States' Action Plans (required by the Electricity Regulation to fulfil the 70% cross-zonal transmission capacity criterium), except to a limited extent in the plans of Germany, Austria, the Netherlands and Hungary. While the full toolbox of GETs might take time for TSOs to get acquainted with, concerning DLR specifically, there have been several pilots launched

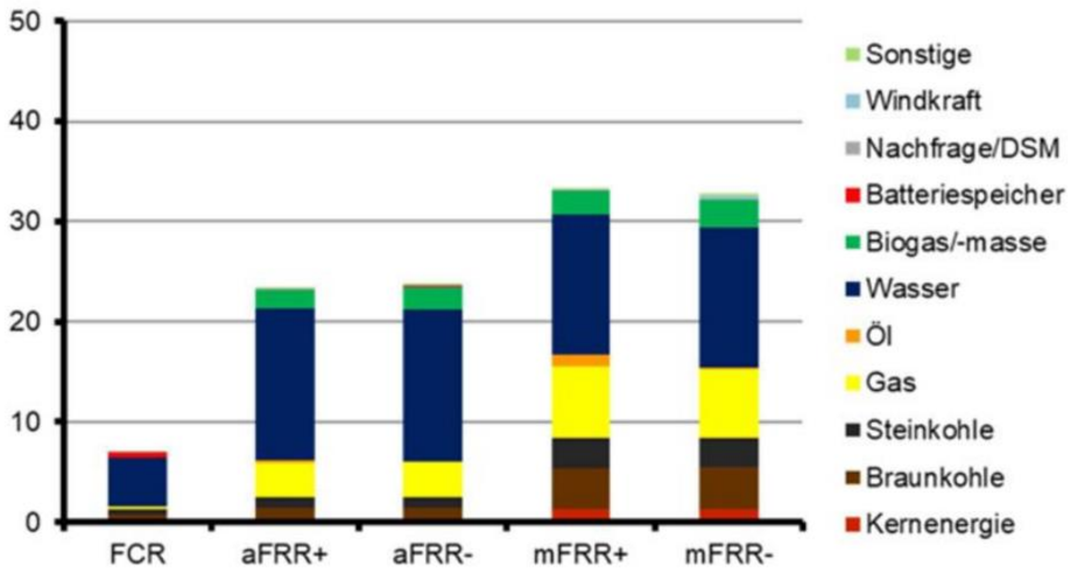
[44] IRENA (2020) Dynamic Line Rating – Innovation Landscape Brief
[45] CurrENT (2024) Recommendations for the deployment of DSO projects
[46] Mainly from North America and Europe
[47] A-Guide-to-Case-Studies-for-Grid-Enhancing-Technologies.pdf (inl.gov)
[48] For the UK, US, Germany and Belgium
[49] Conclusions | Massive Renewables uptake through enhanced grids. A transatlantic perspective - currENT (currenteurope.eu)
[50] FERC approves CAISO, NYISO, utility plans for ambient line ratings to boost transmission capacity | Utility Dive
[51] 220530_currENT-policy-paper-Grid-Enhancing-Technologies-to-support-TSOs-achieve-the-70-target-1.pdf (currenteurope.eu)

in Europe already[52] and the technology is, for example, applied since 2008 on congested lines by the frontrunner in this domain, Belgium's Elia[53].

3.1.3. Standard technologies to provide system services

Network expansion and grid-enhancing technologies do not fully address some challenges faced by network operators. In particular, they cannot address all balancing needs. There are various solutions however which network operators may adopt to address these needs. TSOs and DSOs have a toolbox at hand for balancing and congestion management, but how these tools are deployed depends on the regulatory framework in the country, the amount of distributed flexibility resources available, the desired timeframe and the local situation at hand.[54] The below graph shows the types of prequalified balancing capacities in Germany in 2022, where balancing capacities are offered especially by hydropower and gas-powered power plants (mainly OCGTs), but also biogas/biomass-based power plants, and increasingly other resources such as wind energy and solar PV generators or demand-side flexibility.

Figure 11 Prequalified balancing capacity (in GW) in Germany differentiated by primary energy source and balancing product[55]



3.2. Cross-system solutions to address network challenges

Cross-system solutions to address network challenges are assessed in this study based on the following criteria:

- Contributions to address the identified network challenges
- Replicability/scaling potential
- Costs
- Implementation timeline
- The novelty of the solution.

[52] Dynamic Line Rating: Innovation Landscape Brief (irena.org)
[53] Dynamic Line Rating (elia.be)
[54] TSO–DSO REPORT – An integrated Approach to Active System Managament (edsoforsmartgrids.eu)
[55] Source: Beschreibung von Konzepten des Systemausgleichs und der Regelreservemärkte in Deutschland (regelleistung.net)

The final set of cross-system solutions selected for characterisation in the study based on these criteria comprises the following options:

- **Demand side flexibility and storage assets**
- **Digitalisation**
- **Local flexibility and EU balancing platforms**
- **TSO/DSO cooperation**
- **Innovations in flexible network access**
- **Time-differentiated and locational network tariffs**
- **Microgrids**

Figure 12 briefly describes grid-enhancing technologies presented in the previous section as well as the cross-system solutions selected for analysis. The main solutions (both GETs and cross-system) can be further broken down in sub-solutions. The wide range of solutions is a particular challenge of this study, which requires some selection to make the analysis feasible. The detailed analysis of the cross-system solutions can be found in the fiches of Annex I, and forms the basis for the comparative analysis of the main body of this study.

Figure 12 GET and selected cross-system solutions discussed in the study

Solution	Description	Examples of sub-solutions
Network-focused solutions		
Grid-enhancing technologies	Maximize the available transmission or distribution capacity across the existing system	Dynamic line rating
		Dynamic transformer rating
		Power flow controllers
Cross-system solutions		
Demand side flexibility and storage assets	Assets which can modify their off-take and/or injection patterns based on commodity or grid tariff (price) signals or explicit financial incentives	Electric vehicles
		Stationary batteries
		Building and process heating systems
Digitalisation	Investments in and optimal use of various digital assets that enable and improve both network management and energy management by grid users	Home energy management systems
		Building energy management systems
		Energy resource management systems
Local flexibility and EU balancing platforms	Platforms which facilitate or coordinate transactions for requesting, offering, trade, dispatch and/or settlement of energy or system services between T/DSOs and DER/other flexibility providers[56]	Local flexibility platforms / markets
		EU balancing platforms
TSO/DSO cooperation	Cooperation between the two network operator types in data exchange, joint system operation or connection-related activities	Data exchange
		Joint system coordination
		Connection-related activities
Innovations in flexible network access	Connection options that free up capacity for additional injection or offtake, where firm connection agreements are not possible due to lack of grid capacity	Flexible (interruptible) connection agreements Time- or load-dependent network access
		Changes in network codes
Time and location-differentiated grid tariff	Dynamically or pre-set electricity network tariffs based on time-of-use or location-specific grid conditions,	Pre-set time-of-use network tariffs
		Dynamic network tariffs
		Pre-set locational network tariffs
Microgrids	Localised power systems that can operate independently of the main electricity grid	AC microgrids
		DC Microgrids

Differentiating the selected solutions

The selected solutions differ greatly in their nature (physical assets, data management, market-based measures, cooperation initiatives etc.), but they can all deliver benefits to

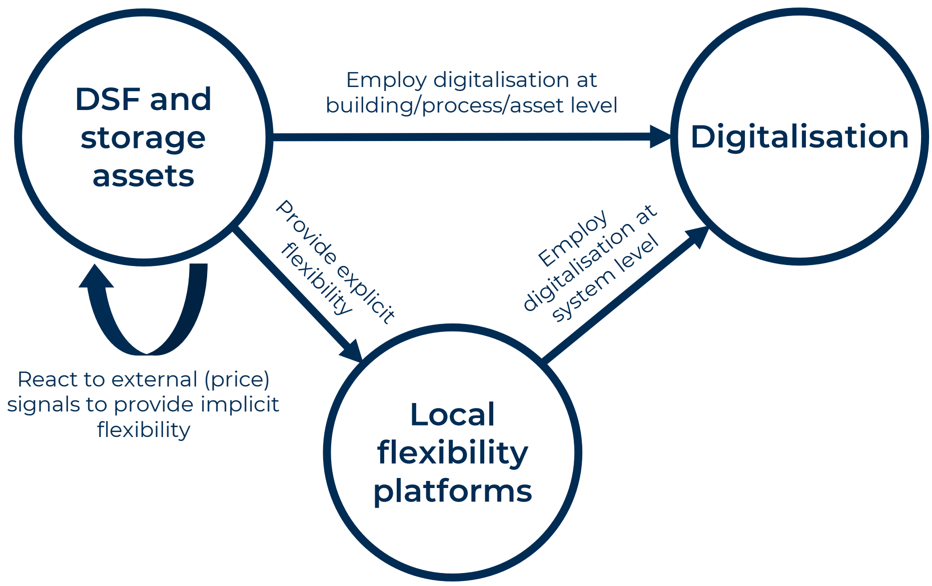
[56] ENTSO-E and Frontier Economics (2021) Review of flexibility platforms

network operators and market participants by reducing the need for network expansion and increasing the available flexibility. Some act as enablers (like digitalisation), some are direct providers of flexibility (like DSF assets), resulting in a diverse toolbox of solutions. Time-differentiated and locational tariffs, for example, are a very different solution to DSF assets, but due to their role in guiding investments and incentivising optimal grid use patterns, they can contribute to the same goal.

At the same time, there is some overlap between certain solution categories, which represents another challenge. This concerns particularly the overlap between DSF and storage, digitalisation, and local flexibility platforms. The following characteristics serve to differentiate DSF and storage assets, digitalisation, and local flexibility platforms:

- **DSF and storage assets:** this solution refers to the physical grid connected assets which can adjust their off-take and/or injection in response to price/tariff signals or payments for the provision of flexibility services. However, their deployment often needs to be combined with other solutions, which can be seen as enablers to leveraging DSF and storage assets. These enabling solutions comprise particularly digitalisation (smart meters), flexibility platforms and aggregators;
- **Digitalisation** comprises investments in and optimal use of various digital technologies that can enable and improve both network management and energy management by grid users. As such, digitalisation solutions can be deployed at the network or building/process level (but are broader solutions than the individual assets providing flexibility) or can be deployed at a much broader scale;
- **Local flexibility platforms** facilitate transactions for requesting, offering, trade, dispatch and/or settlement of energy or system services. As such, they require the deployment of digitalisation solutions to leverage flexibility provision by DSF and storage assets – but also involve regulatory aspects such as the definition of market rules and products.

Figure 13 Interrelations between DSF and storage assets, digitalisation and flexibility platforms



Energy efficiency measures to address network challenges

In addition to the selected cross-system solutions indicated above, **energy efficiency can have a direct impact on the peak load, thereby helping address the challenges** of insufficient connection capacity and bottlenecks due to congestion. While energy efficiency measures are not analysed in detail in the remainder of this report,[57] we discuss this topic briefly in this section, given the energy efficiency first principle and their potential contributions to deferral of grid expansions.

Non-wire alternative solutions are often considered to include energy efficiency measures (given their potential to decrease peak load). In fact, while recent public data is not available, energy efficiency measures constituted (at least in the past) a majority of non-wire alternative projects in the US.[58] This is in line with the energy efficiency first principle and the fact that energy efficiency measures provide a number of complementary benefits in addition to deferral of grid expansion.

Energy efficiency measures which contribute to addressing network challenges and have an involvement of network operators can be separated in two categories:

- **Measures to increase energy efficiency of network users**, particularly consumers, where network operators might have a role in, for example promoting campaigns to reduce energy consumption;
- **Measures to reduce network losses** adopted by network operators themselves.

Article 9 of the Energy Efficiency Directive II allows Member States to fulfil their energy savings obligations by implementing energy efficiency obligation schemes, which can be administered, among other entities, by electricity TSOs or DSOs. However, in most Member States that have chosen to implement obligations, the managing authority is most frequently a ministry or energy agency, and in a few cases the NRA (such as in Poland).[59] End-use energy efficiency is in the EU seen rather as a responsibility of policy makers, energy agencies and retailers. Hence, no public data was identified compiling EU network operators' initiatives to increase the energy efficiency of network users, although specific programs can exist. The EU literature is more focused on the reduction of network losses, which is detailed next.

Article 27 of the Energy Efficiency Directive II establishes requirements for Member States, NRAs and network operators aiming to increase the energy efficiency of electricity (and gas) transmission and distribution networks. Relevant provisions include:

- MS should ensure network operators apply the energy efficiency first principle in network planning, network development and investment decisions
- NRAs (or another designated authority) "shall verify that methodologies used by transmission system operators and distribution system operators assess alternatives in the cost-benefit analysis and take into account the wider benefits of energy efficiency solutions"
- NRAs "may provide methodologies and guidance on how to assess alternatives in the cost-benefit analysis"
- MSs "shall ensure that transmission and distribution system operators monitor and quantify the overall volume of network losses and, where it is technically and financially feasible, optimise networks and improve network efficiency"

[57] In this report, energy efficiency measures refer to measures which permanently reduce electricity consumption, and should not be confused with demand-side flexibility measures which, among others, can momentarily reduce energy consumption but not permanently reduce it. .
[58] GreenTech Media (2018) Divining the Data on the US Non-Wires Alternatives Market
[59] ENSMOV (2020) Snapshot of Energy Efficiency Obligation Schemes in Europe (as of end 2019)

- MSs "shall encourage transmission and distribution system operators to develop innovative solutions to improve the energy efficiency of existing and future systems through incentive-based regulations"

EU Member States have very different incentives for TSOs and DSOs to reduce network losses,[60] for example including the cost of losses as part of the revenue cap, incentives on the volume or price of losses, specific bonus incentives, or yardstick competition measures.[61]

3.3. Network challenges addressed by cross-system solutions

This section assesses the capacity of the selected cross-system solutions to address the network challenges described in chapter 2. This is based on a review of studies and other sources covering broader cross-system solutions, the cross-system solutions fiches presented in Annex I (which is based on solution-specific literature) as well as additional quantitative information on benefits of the solutions presented in section 3.4. As the actual capacity of individual solutions to address network challenges will strongly depend on the specific case, this section rather aims to discuss the *potential of the solutions to address network challenges*.

Table 3 presents the potential of each (sub)solution to address specific grid challenges, for each network level (transmission or distribution). The following main considerations can be derived from the table.

The capacity of a cross-system solution to address a challenge is different depending on the solution's underlying assets' connection level and the nature of the challenge. Assets connected to the transmission network can address TSO challenges, while assets connected to the distribution network can address DSO but also some TSO challenges. However, DERs require aggregation in order to have a significant impact on transmission-related challenges, and therefore are better able to address challenges impacting the whole system (such as balancing needs) than transmission challenges with a locational component (such as transmission-level congestion).

Most solutions do not address the challenge of higher complexity to identify system needs. On the contrary, the availability of a higher variety of solutions to address network challenges contributes to this complexity. The only category of solutions which addresses this challenge is TSO/DSO cooperation, which is related to the fact that identification of system needs is intrinsically a task of network operators (which should however equally consider all solutions, within or outside of the network system, and implement the most suitable option from an economic and technical perspective).

Many cross-system solutions exist to address congestion and frequency-related challenges. This is related to the fact that several solutions provide or enable upward or more frequently downward regulation, which can be used for congestion management and/or balancing purposes. However, fewer solutions are able to address grid connection capacity challenges to a high degree, as this requires addressing structural congestion by consistently limiting the peak loading of the relevant network elements, which cannot be achieved with curative congestion management only.

[60] CEER (2024) Report on Regulatory Frameworks for European Energy Networks 2023
[61] JRC (2020) Improving Energy Efficiency in Electricity Networks

The availability of solutions to address non-frequency ancillary services is relatively more limited. Some solutions can be technically suitable and even commercially mature for the provision of such services, but there is less experience in e.g. the use of DERs for voltage control. For example, while a few local flexibility platforms are operating commercially, very few platforms aim to facilitate voltage control.[62]

Table 3 Potential contributions of GETs and cross-system solutions to address network challenges

Solution	Examples of sub-solutions	Higher complexity to identify system needs		Limited grid connection capacity		Limited cross-zonal capacity & low utilisation		Increasing congestion in networks		Increasing balancing needs		Non-frequency ancillary service needs	
Grid-enhancing technologies	Dynamic line rating	H	H	H	H	H		H	H			M	M
	Dynamic transformer rating	H	H	H	H	H		H	H			M	M
	Power flow controllers	H	H	H	H	H		H	H			M	M
Demand side flexibility and storage assets	Electric vehicles				M			H	H	H			U
	Stationary batteries				M			H	H	H			U
	Load shifting				M			H	H	H			
Digitalisation	Home energy management system				M			H	H	H			
	Building energy management system			M	M			H	H	H		M	M
	DERMS			H	H			H	H	H		H	H
Local flexibility and EU balancing platforms	Local flexibility platforms / markets			M	M	H		H	H	H		M	M
	EU balancing platforms					H				H			
TSO/DSO cooperation	Data exchange	H		H	H			M		M		H	
	Joint system coordination					M		M	M	M		M	M
	Connection-related activities	H	H	H	H								
Innovations in flexible network access	Flexible connection agreements			M	M			M	M				
	Time-dependent network access			M	M			M	M				
	Changes in network codes			M	M			M	M			H	H
Time-of-use and locational network tariffs	Time-of-use network tariffs			H	H			M	M				
	Locational network tariffs			H				H					
Microgrids	AC/DC microgrids				H				H	H			U

: Transmission; : Distribution; **H**igh / **M**edium / **U**ntested potential to address challenge

[62] ENTSO-E and Frontier Economics (2021) Review of flexibility platforms

3.4. Costs and benefits of cross-system solutions

This section assesses the costs and benefits of cross-system solutions. It complements the analysis above by 1) compiling available quantitative data available in the literature and 2) comparing the costs and benefits for the different solutions.

Table 4 presents data available in the literature on costs & benefits of different cross-system solutions, for different sub-solutions and geographies. CAPEX, OPEX and (network-related) benefits are mentioned where available, but these figures are not fully comparable, for the reasons indicated in the table.

Table 5 presents a qualitative assessment of the implementation timeline, costs and network-related benefits of network-centric and cross-system solutions. The assessment is based on the quantitative data collected, the solution fiches presented in the Annex I as well as expert judgement. As it is impossible to provide a precise assessment of the costs and benefits of each solution, the table aims to give a qualitative indication for each solution.

Factors influencing the comparison of the solutions

It is challenging to categorise and rank the solutions according to their potential net benefits. Each solution comprises multiple sub-solutions, which have specific characteristics and vary in their costs & network benefits. As all solutions can either directly regulate active power or indirectly enable this regulation, they can all contribute to a relevant extent to congestion management and balancing. The capacity of some solutions (such as digitalisation and TSO/DSO cooperation) to provide or enable the provision of non-frequency ancillary services can be lower, but there is also less experience with such applications. Furthermore, there is no common categorisation of the benefits, meaning the available CBAs can differ regarding whether benefits to market parties are also considered (or only benefits to network operators), whether gross (excluding costs) or net benefits (discounting costs) are presented, and how benefits are presented (total value in a given year, throughout the lifetime of the project, or calculated as the net present value). Other issues such as whether benefits (and costs) are indexed also impact comparability, particularly given higher inflation in the last years.

Table 4 Identified quantitative costs & benefits of cross-system solutions

Solution	Sub-solution	Case	Region	CAPEX	OPEX	Benefit type	Benefits
Demand-side flexibility and storage	Demand-side flexibility and storage[63]	Home appliance load shifting for grid investment deferral	CIGRE MV distribution grid benchmark	N/A	350 €/d	DSO avoided CAPEX Avoided generation OPEX	12 k€ (net, 55 congested days) Up to 32.5 k€ (1 congested day)
Demand-side flexibility and storage	Demand-side flexibility and storage[64]	Extrapolation of DSF grid deferral benefits from DE estimate	EU-27	N/A	N/A	TSO+DSO avoided CAPEX	11.1 – 29.1 B€/y
		Various DSF solutions for provision of balancing services	EU-27	N/A	N/A	Balancing savings	262-690 M€/y
Demand-side flexibility and storage	Storage, demand response + classical expansion[65]	Storage and DR for grid investment deferral	BeNeLux	87.5 M€	N/A[66]	Avoided load+ generation curtailment costs	>41 B€
			Nordic countries	269.9 M€			>18 B€
Demand-side flexibility and storage[67]	Demand-side flexibility and storage	EV smart charging for various grid benefits	US Midwest	0.9 M€	N/A	Avoided generation CAPEX & OPEX TSO+DSO avoided CAPEX	1.6 M€
		Solar PV + behind-the-meter storage flexibility for various grid benefits	US Western region	7.1 M€	1.2 M€	Avoided generation CAPEX & OPEX Avoided GHG emissions TSO+DSO avoided CAPEX	12 M€
Digitalisation	DERMS[68]	DERMS for freeing up more grid capacity	UK	N/A	N/A	Balancing savings Voltage control savings	290 M€
Local flexibility and EU balancing platforms	TERRE (RR) platform	Development of EU balancing platforms for cross-border sharing of balancing reserves or energy	CH, CZ, ES, FR, IT, PL, PT	11.35 M€	1.58 M€/y	Balancing savings	810 M€/y
	MARI (mFRR) platform		EU-27, CH, NO	17.91 M€	0.12 M€/y	Balancing savings	n.a
	PICASSO (aFRR) platform		EU-27, CH, NO	5.85 M€	0.49 M€/y	Balancing savings	200 M€
	IGCC (IN) platform		EU-27, CH	0.2 M€	0.04 M€/y	Balancing savings	>750 M€/y
	FCR cooperation platform		AT, BE, CH, DE, DK, FR, NL, SI	N/A	N/A	Balancing savings	67 M€/y
TSO/DSO cooperation	Data exchange[69]	Various cooperation approaches, including data exchange between generators and ISO/DSOs	UK DSO (WPD) network	N/A	N/A	Balancing savings	35-52 M€/y
TSO/DSO cooperation	Joint system operation[70]	Joint procurement of congestion management services under various configurations	IT, ES	84-148	17-30	Balancing savings CM savings	10-37 M€
Innovations in flexible network access	Flexible connection agreement[71]	FCAs for connection of distributed wind, solar and CHP generators	UK Scenario 3	4.6-4.8 M€	N/A	DSO avoided CAPEX Reduced generation curtailment	26.3 – 21.6 M€

[63] Bødal et al. (2022) Demand flexibility modelling for long term optimal distribution grid planning
[64] DNV (2023) 2030 Demand side flexibility: quantification of benefits in the EU
[65] FlexPlan (2023) D5.2 Grid development results of the regional studies
[66] OPEX results of FlexPlan D5.2 include storage electricity costs for charging and are hence not presented here.
[67] NESP (2022) Benefit-Cost Analysis Case Studies - Examples of Distributed Energy Resource Use Cases
[68] Smarter Grid Solutions (2021) Smarter Grid Solutions appointed as Active Network Management partner for innovative project set to save networks £250 million
[69] WPD et al. (2021) Technical & Cost Benefit Analysis of the Nominated Test Cases and Respective Solutions
[70] Rossi et al. (2020) TSO-DSO coordination to acquire services from distribution grids: Simulations, cost-benefit analysis and regulatory conclusions from the SmartNet project
[71] Anaya and Pollitt (2013) Finding the Optimal Approach for Allocating and Realising Distribution System Capacity: Deciding between Interruptible Connections and Firm DG Connections

It is also difficult to assess and compare the costs of the solutions. This constrains the usefulness of compiling such data in the present study – but attempting to do so can still provide insights into the factors influencing the costs and benefits of the solutions. Determining the standard cost for providing network and system services is a complex calculation involving technical, financial, and regulatory considerations. Precise modelling and thorough analysis are needed to make informed decisions and ensure technically suitable and cost-efficient service provision. Calculations should also consider factors that extend beyond the straightforward capital expenditures (CAPEX) and operational expenditures (OPEX) associated with the asset, such as:

- **Solution type**: the cost calculation hinges on the nature of the network solution. Each network-centric approach and cross-system solution has different implications. Network-centric solutions may address specific network challenges more effectively but their implementation could lead to higher costs or be hindered by delays or constraints in the supply chain;
- **Scope of costs**: the literature sources use significantly different definitions of the costs (as for benefits), for example whether electricity purchase costs for charging of storage is included in OPEX or not. Also how investment costs are considered (as overnight costs or whether the construction period duration and associated financing costs are taken into account) influences the results – not only for alternative solutions, but also for traditional network expansion, given its long lead time.[72]
- **Asset lifetime**: the lifespan of the asset plays an important role. A short-lived asset leads to higher annual depreciation charges compared to a longer-lived asset (if capital expenditures are the same), while a longer lifespan allows for spreading depreciation charges over a longer time period;
- **Cost of capital**: the financing structure and interest rates significantly impact cost. High capital costs can inflate the overall expenditure, mainly affecting the cost of the standard solution (network expansion);
- **Revenue regulation:** regulatory frameworks influence cost determination and recovery. Parameters set by regulators—such as allowed returns on equity or RAB—directly impact the financial viability of investment projects undertaken by DSOs/TSOs versus their procurement of alternative solutions from market parties;
- **Specific characteristics**: specific characteristics related to the injection and withdrawal profiles of grid users, and specific conditions under which the network solution is deployed affect the cost structure of electricity grids. These characteristics include load and consumption patterns, geography (urban vs. rural grids, remote locations), voltage levels, network usage intensity (industry vs. residential consumers) and the prevailing metering and billing systems (wide-spread smart meter deployment allow for better load management).

[72] CurrENT (2024) Recommendations for the deployment of DSO projects

Table 5 Rating of costs & benefits of network-centric and cross-system solutions

Solution	Implementation timeline	CAPEX	OPEX	Network-related benefits
Network expansion	Long-term: >5 years	High	Low - Medium	Grid investment deferral Congestion management
Grid-enhancing technologies	Short-term: 1-3 years	Medium	Medium	Identification of system needs Grid investment deferral Congestion management Non-frequency AS
Demand side flexibility and storage assets	Short-term: 1-3 years	Medium	Low	Grid investment deferral Congestion management Balancing Non-frequency AS
Digitalisation	Short/Medium-term: 1-5 years	Medium	Medium	Grid investment deferral Congestion management Balancing Non-frequency AS
Local flexibility and EU balancing platforms	Medium-term: 3-5 years	Medium	Medium	Congestion management Balancing Non-frequency AS
TSO/DSO cooperation	Short/medium-term: 1-5 years	Low- medium	Low -Medium	Identification of system needs Congestion management Balancing Non-frequency AS
Innovations in flexible network access	Short-term: 1-3 years	Low	Low	Grid investment deferral Congestion management Balancing
Time-of-use and locational network tariffs	Short-term: 1-3 years	Low	Low	Grid investment deferral Congestion management
Microgrids	Short/medium-term: 1-5 years	Medium	Medium	Grid investment deferral Congestion management Balancing

Aspects influencing the costs and benefits of the solutions

A number of relevant insights can be drawn from the data and comparison of the solutions. The costs and total benefits of GETs and alternative cross-system solutions as well as their overall suitability to address specific challenges of a given network operator will depend on a number of aspects, including:

- **Frequency of activation**: solutions with high fixed costs (whether CAPEX or fixed OPEX) will have comparatively higher net benefits when activation is more frequent – for example to address structural congestion. Conversely, situations where activation is less frequent will favour the use of low fixed costs solutions;
- **Predictability of the network challenge**, as solutions with a shorter activation time (such as assets providing demand response) might perform better to address challenges with high uncertainty, while solutions such as time-of-use network tariffs can be less suitable to address for example non-recurrent congestion;
- **The network level of the challenge,** given distribution challenges can only be addressed by assets deployed at the distribution levels, while transmission/system challenges can be addressed by assets at the transmission level as well as under certain conditions by (often aggregated) assets at the distribution level. This is particularly important given that distribution networks might be a more important driver than transmission of overall congestion costs in the future;[73]

[73] FlexPlan (2023) Grid development results of the regional studies

- **Co-benefits provided by the solution's participation in other electricity markets** such as wholesale, capacity or other markets. Many solutions will depend on additional revenues perceived from participating in especially wholesale markets (as detailed below). This improves the business case of the solution (and thus overall deployment) but is affected by the ability of the solution to stack revenues streams;
- **Other utility perceived by asset owners.** Most assets are primarily deployed to offer other utility to their owners than the revenues obtained in flexibility or wholesale markets, particularly in case of demand-side flexibility assets. EVs provide mobility services and heat pumps provide space and water heating for example. This utility is critical for the overall deployment levels, as well as one of the reasons that many demand-side flexibility assets are assessed to have low CAPEX – EVs are still quite expensive, but the investment costs are not allocated to the flexibility service provision;
- **Whether only new assets or also existing assets (at no or limited CAPEX) can be leveraged to address network challenges**. In many cases only new assets can address the specific network challenge. For example, already-deployed EVs and/or charging stations might not be capable of bi-directional charging, and new grid connection agreements will typically only apply to new network users;
- **Total solutions' potential available.** High deployment levels can be necessary in order to adequately meet network operator needs, and solutions with a limited potential might not be worth the effort (unless they can be combined with other solutions). For example, as the number of EVs, heat pumps, HEMS/BEMS or microgrids deployed varies significantly depending on the market (although they are expected to increase across all EU markets), their potential contribution is still quite limited in most markets. However, increasing deployment will lead to economies of scale, since solutions typically have fixed costs which do not scale proportionally to deployment – particularly costs of ICT systems;
- **Other characteristics of the network challenge and solutions.** For example, demand response will be limited by behavioural preferences, storage's total activation duration is limited by its capacity and need to recharge, and PV capacity to provide downward regulation depends on the weather conditions;
- **Assumptions on the counterfactual to assess net benefits.** There is no standardised approach to conduct a cost-benefit analysis for the deployment of cross-system solutions. Depending on the assumptions, benefits can vary significantly. This is compounded by the fact that many solutions assessed are enablers, facilitating the deployment of other solutions such as demand-side flexibility.

As indicated above, **cross-system solutions also provide benefits from participation in not only ancillary but also wholesale and capacity markets (which is not a focus of this study).** An important benefit of cross-system solutions is avoided generation costs, which can be the most important benefit and single-handedly justify the deployment of cross-system solutions in certain cases.[74] In EU Member States and elsewhere, avoided generation costs are an important part of cross-system solution benefits. In vertically-unbundled electricity markets the benefits constitute additional wholesale or capacity market revenues perceived by the owners of the assets. Thus, despite the focus of the

[74] RMI (2018) The Non-wires Solutions Implementation Playbook - a Practical Guide for Regulators, Utilities, and Developers

present analysis being on the contributions of the solutions to network challenges, benefits realised in wholesale markets remain important in order to ensure a viable business case for some solutions. Generation curtailment costs can also be reduced by the deployment of cross-system solutions. As such costs can have an impact on the net revenues of system operators, they fall in the scope of this study.

Moreover, solutions are not mutually exclusive – on the contrary, there are many synergies. Digitalisation, local flexibility platforms and TSO/DSO cooperation are seen as enablers of demand-side flexibility and storage assets. There are also synergies between GETs and cross-system solutions, as well as between classical network expansion and cross-system solutions – in the regional grid development studies of the FlexPlan study, the expansion planning optimisation frequently identifies the deployment of new lines and transformers as well as storage and/or flexible loads as the optimal solution to relieve congestion in the six European regions analysed.[75]

Increased competition can favour the deployment of cross-system solutions. If multiple competing solutions are available, this might reduce the potential revenues received by the concerned operators but facilitate the adoption of market-based mechanisms for network operators procuring ancillary and congestion management services, which in the long-run could benefit the deployment of cross-system solutions and reduce the overall system costs.

Most GETs and cross-system solutions identified can be deployed in the short-term. Solutions which require the implementation of complex IT solutions may need over 3 years for their deployment, and thus are considered in most cases to be medium-term (taking 3 to 5 years for implementation). This is still relatively fast compared to standard wire-based solutions to address network challenges: ACER's latest report on the progress of Projects of Common Interest indicates the "average (actual or expected) duration of the electricity transmission PCIs' implementation … is 10 years",[76] while the EU Action Plan for Grids indicates that "waiting time for permits for grid reinforcements are between 4-10 years, and 8-10 years for high voltage lines".[77]

No solution identified on its own fully addresses the network challenges. Given the expected significant increase in distributed energy resources and electrification of end-uses, solutions which address congestion/connection capacity challenges do not obliviate the need for network expansion, and it is likely that in many cases they do not even defer investment needs. Rather, given the significant lag between necessary and realised grid expansion investments caused by permitting and public acceptance issues as well as technical constraints (e.g. lack of skilled personnel), GETs and alternative cross-system solutions bring total investment needs closer to feasible levels. For ancillary service-related challenges (frequency and non-frequency), it is possible that solutions identified will account for a significant share of the flexibility needs of TSOs. However, no single solution is able to cover the specific TSO needs across all balancing product types and areas. Hence, the efficient mix of solutions for balancing services' provision will combine a range of solutions, including a number of new non-fossil based technologies as the traditional fossil-based balancing service providers will gradually reduce their participation.

[75] FlexPlan (2023) Grid development results of the regional studies
[76] ACER (2022) Consolidated report on the progress of electricity and gas Projects of Common Interest
[77] European Commission (2023) Grids, the missing link - An EU Action Plan for Grids

Solutions with a very short implementation timeline or low total costs should always be considered. For example, innovations in flexible network access and time-of-use or locational network tariffs have both low CAPEX and OPEX, and can be implemented in the short-term. Even if in some cases the net benefits can be limited, these solutions can still present an attractive benefit-to-cost ratio due to their low costs, and constitute a pro-active approach to minimise network challenges.

4. Transaction costs and other barriers for implementation of cross-system solutions

In this chapter, we review the barriers to the implementation of the selected cross-system solutions. These barriers primarily consist of (high) transaction costs (with multiple subcategories). We will also consider other barriers, such as the network operators' bias towards non-investment solutions, and regulatory barriers that make specific cross-system (sub)solutions less feasible.

The remainder of the chapter is structured as follows:

- Section 4.1 describes our approach to analysing transaction costs
- Section 4.2 details the approach to analyse other barriers
- Section 4.3 analyses transaction costs for each cross-system solution
- Section 4.4 analyses other main barriers identified for each cross-system solution as well as the role of NRAs and network operators

4.1. Approach to transaction costs

A main barrier that hinders large-scale implementation of specific cross-system solutions is higher transaction costs. Transaction costs refer to any costs related to making transactions for an economic system involving different actors. This concept was first introduced in 1931 in the institutional economics field, where transactions of a firm are considered as the unit of analysis (versus output in neoclassical economic theory).[78] The analysis was later extended outside of institutional economics, and of firms, to study more widely the impact of transaction costs on production and other economic activities.[79]

The relevance of transaction costs in an economic system depends on four factors[80]:

- Persistent uncertainty in the field of analysis.
- The number and amount of transactions are generally limited, by a combination of few assets available for trade, low frequency of exchange, and limited entities offering alternatives for a given transaction.
- Transacting entities are limited in the information they can acquire and process related to transactions (i.e. information asymmetries can occur). Thus, they rely on bounded rationality.
- Transacting entities can have preferences that conflict with each other, leading to the need for enforcement.

All four factors are seen in the challenges connected to the electricity system, particularly for grid operation:

- Uncertainty about electricity supply and demand levels and patterns in the future, leading to (among others) uncertainty about network investment needs.

[78] John R. Commons (1931), Institutional Economics, American Economic Review, Vol.21.
[79] Oliver E. Williamson (1979), Transaction-cost Economics: the governance of contractual relations; Journal of Law and Economics, 22, 2.
[80] https://www.britannica.com/money/transaction-cost

- Low number of network development projects (i.e. projects within the electricity system grid operation, as compared with the rest of the electricity system), with few alternatives for any given grid investment need.
- Relatively high information asymmetries, for reasons including protection of trade secrets and security.
- Long-term conflicts in preferences of different actors (regulators, network operators, end-users, generators, etc.) who are involved in transactions related to cross-system solutions. For example, regulators may seek to maximise social welfare, while network operators may aim to maximise their returns, and these goals are not expected to change in the short term.

The combination of these factors makes transactions difficult and costly. Often, the solution for reducing transaction costs in such markets is vertical integration. However, the ongoing efforts towards energy markets' liberalisation have moved the electricity system in the opposite direction, and have increased the number of transactions between different actors. The decentralisation of the energy system, whereby the power generation system is transiting from large-scale facilities to smaller local generation units, also contributes to this trend. Overall, the transaction costs in the electricity system are increasing due to multiple factors.

Analyses of transaction costs have been undertaken for other energy policy domains. For example, a prior analysis of the barriers to energy efficiency improvements focuses on the role of transaction costs in slowing down the adoption of the expected improvements.[81] Another study reports on transaction costs for energy efficiency improvements, renewable energy deployment, and carbon markets.[82]

Transaction costs are generally categorised into:

- **Search and information costs**. These costs relate to determining the availability (including quantity, timeliness, etc.) and quality (i.e. how well the product/service satisfies the need) of products/services on the market.
- **Bargaining and decision costs**: These are costs required for agreeing on and contracting the procurement of a product/service.
- **Policing and enforcement costs**: These two costs become relevant following a contract's entry into force. Policing costs refer to verifying that each party respects the terms set out in the contract. Enforcement costs are relevant when one contracting party does not follow these terms, and relates to costs incurred to enforce that it does so (e.g., litigation costs) and/or to penalise it otherwise.

Transaction costs inherently depend on the transacting parties. In this study, we focus on transactions between the following parties: TSOs/DSOs, NRAs, nominated electricity market operators (NEMOs), energy suppliers, generation and storage asset operators, end-users, and other more novel actors (such as independent aggregators and e-mobility service providers).[83] Transactions with parties outside of the electricity system are not considered in this study. For example, the purchasing of HEMS systems often involves just the building owner and the HEMS retailer/OEM. While the building owner can be considered a party in the energy system, it is more difficult to consider retailers of off-the-

[81] Huenecke et al (2019), What role do transaction costs play in energy efficiency improvements and how can they be reduced?
[82] Mundaca et al (2013), Transaction costs analysis of low-carbon technologies; Climate Policy, 13:4.
[83] Parties may also be referred to as BRPs or FSPs, depending on context.

shelf HEMS devices as such. These transactions are less influenced by parties in the energy system, such as NRAs and SOs, when compared with other transactions in the energy system (such as activation of assets connected to HEMS). Thus, their transaction costs are considered out of scope.

Identifying the relevant transactions and estimating the related costs, even qualitatively, is challenging. Cross-system solutions can have varying actors, transactions, contracting aspects, and legal frameworks, which inhibits a rigorous comparison of transaction costs across the solutions. We aim to underpin this comparison by using multiple indicators, which relate to differences in transaction costs:

- **Characteristics of transactions**
  - Transaction nature: long-term contract (binding), agreement (non-binding), over-the-counter trade, trade in organised market
  - Frequency of transaction (one-off, continuous, daily, annual, etc.)
  - Functionality of platforms or markets[84] for transactions (liquidity, competitiveness, market concentration, etc.)
  - Regulation over transactions (e.g., requirements for specific procurement procedures)
- **Transacting parties**
  - Type and number of parties involved
  - Information asymmetry between parties

Some additional aspects can also impact the costs of a transaction. For example, regulation over specific transacting parties can impact some or all transactions in which that party is involved. The complexity of internal processes for transacting parties can also impact the costs of any transaction that requires internal actions. We will also reflect on specific aspects related to each cross-system solution where deemed relevant.

In the next sections, we will also identify specific case studies that illustrate good approaches to reducing transaction costs. These cases are described in textboxes highlighting the main transaction costs, and the main actions taken to reduce them, along with a summary of the background context of the case.

4.2. Approach to other barriers

Next to high transactions costs, other barriers that may hinder the uptake of alternative cross-system solutions are legal/regulatory, organisational, social, financial, and technical barriers (among others). These barriers will not be considered comprehensively, rather those barriers (other than transaction costs) will be highlighted for each cross-system solution when deemed to be significantly hindering its adoption/deployment.

Regulatory barriers are still a hurdle for several alternative solutions. Developments in various EU legislations, including the Electricity Regulation, the Electricity Directive, the Renewable Energy Directive, the Alternative Fuel Infrastructure Regulation, and various Network Codes, have greatly facilitated the possibility for deploying alternative solutions. However, the lack of adequate implementation (and transposition) and limited

[84] Note that we use the term "market" here in a broad economic sense; some transactions will take place via bilateral agreements, hence not via a liquid and/or competitive trading platform.

enforcement of these rules has led to remaining regulatory barriers for some cross-system solutions.

The identification of the regulatory barriers that hinder the deployment of alternative solutions, is amongst others based on ACER's analyses and monitoring activities on regulatory aspects across the EU. The main regulatory barrier to consider for alternative solutions relates to how grid investments are remunerated. Specific choices regarding the revenue regulation of network operators can create specific biases in their investment and operational decisions.

The main bias not considered within transaction costs is CAPEX bias, which relates to how regulated entities are remunerated and can recover their costs. Three cases can encourage TSOs/DSOs to favour CAPEX-heavy (and OPEX-light) options[85]:

- When the regulated rate of return is higher than the actual cost of capital.
- Asymmetric regulation of CAPEX and OPEX returns. For example, regulations can allow a markup on the recovery of CAPEX, while OPEX are recovered on a per-cost basis.
- Disadvantaging OPEX, by for example not capturing OPEX risk in the regulated return (for example by transferring OPEX on a per-cost basis).[86]

In such cases, the main revenue growth factor for regulated entities (specifically in this context network operators) is increasing CAPEX levels, and not OPEX levels, as the former is the only source of additional returns. Thus, system operators face incentives that are biased towards choosing solutions based on grid investments that are owned by the SO, rather than implementing options than require more OPEX and/or procuring services and/or investments owned by market parties. This can stimulate network operators to undertake grid investments that are inefficient (suboptimal) from a macro-economic and overall electricity system perspective. In addition, they may choose to overinvest. These two issues (preferring CAPEX-heavy investments over OPEX-based solutions and risks for overinvesting in grid assets) are the main barriers for deployment of cross-system solutions.

CAPEX bias is a well-established issue with regulating network goods. This bias was first described by Averch and Johnson in 1962 for publicly-regulated entities.[87] More recently, it has received growing attention not just for energy[88], but also for other public goods.[89] In the context of this study, CAPEX bias is seen as a main issue that affects the approach of grid operators towards solving network challenges.[90] We further consider this bias in the following analysis, but also include other regulatory barriers that relate to specific alternative solutions.

4.3. Analysis of transaction costs of cross-system solutions

Based on the descriptions in Annex I, we reviewed the transaction costs and other barriers for the selected cross-system solutions. As discussed in the previous chapter, many transaction costs in the electricity system are a consequence of the market liberalisation

[85] Smith et al (2019), CAPEX bias and adverse incentive in incentive regulation, OECD Working Papers.
[86] Brunekreeft, G. and Rammerstorfer, M. (2021). OPEX-risk as a source of CAPEX-bias in monopoly regulation, Competition and Regulation in Network Industries, 22(1), 20-34
[87] Averch and Johnson (1962), Behavior of the firm under regulatory constraint, American Economic Review, 52:5.
[88] Alvarez et al (2022), Alternative ratemaking in the US: A prerequisite for grid modernization or an unwarranted shift of risk to customers?; Electricity Journal, 35:9.
[89] Smith et al (2019), CAPEX bias and adverse incentive in incentive regulation, OECD Working Papers.
[90] ACER (2023), Report on Investment Evaluation, Risk Assessment and Regulatory Incentives for Energy Network Projects.

policies and the increasing decentralisation of the system. While the unbundling and other rules such as regulated third-party access have greatly improved social welfare, enhanced competition and facilitated active participation of independent generators and consumers/prosumers in the electricity market, they have led to more transactions and high related costs for several (cross-system and classical) solutions. The transaction costs of cross-system solutions can, in many cases, be connected directly to market liberalisation policies. Examples include various aspects of TSO/DSO cooperation, ownership structures for storage and other flexibility assets, and market operations for balancing platforms.

We focus this analysis on transactions that are connected to and create costs within the energy system. Other transactions, such as those between relevant energy system parties and external actors (such as equipment manufacturers or installers), and transactions where costs were perceived to be negligible, were not considered. Some transactions were also aggregated to avoid repetition (such as "market exchange" for DSF). As the number and cost of transactions can vary greatly between different regions, we refer to only the typical numbers here.

Cross-system solutions differ greatly in the number of relevant transactions; Flexible network access, for example, contains only 2 transactions, while TSO/DSO cooperation consists of 13 transactions across 3 sub-solutions. Transactions that are usually conducted together or related to similar markets and contracts are combined into one transaction, such as the procurement and licensing of DERMS devices (digitalisation solution). Table 6 presents the most relevant transactions (from a transaction cost perspective) for each cross-system solution.

Transactions vary significantly in many characteristics. In terms of frequency of interaction, transactions range from one-off interactions to frequently occurring interactions with many exchanges per day (such as data management activities). More frequent interactions will inevitably lead to more transaction costs, unless specific actions are taken to reduce the costs for each transaction, such as through the automation of processes or the establishment of organised market platforms.

Most transactions related to cross-system solutions are long-term contracts or binding agreements. We identify long-term contracts as those that require a significant financial component (either as an initial or ongoing payment, or as a penalty for breaching contract), while binding agreements are mainly formal agreements with little or no financial requirements. In a few cases, organised market platforms are used to facilitate transactions, and only rarely there are non-binding agreements.

Transactions for cross-system solutions have varying numbers of parties. Some transactions are small interactions between two parties, such as distributed energy resource management systems (DERMS) procurement activities between a system provider and a DSO. Others, such as market exchanges for DSF, can involve many different parties involved at different levels. Transactions that involve multiple parties, with conflicting expectations, incentives, and goals, lead in general to higher transaction costs.

Information asymmetry between parties involved in cross-system solutions is in general not substantially high. Thus, this aspect does not drive transaction costs to the same degree as in other economic sectors. Most transactions connected to cross-system solutions are characterised by a medium or low information asymmetry, and in these cases transaction costs are driven by other factors. Low information asymmetries in this context appear to be due to multiple transparency rules set at both EU and national levels to improve market functionality and limit risks for potential abuse by natural monopoly holders in various areas.

Table 6 Cross-system solutions transaction summary, ordered based on impact of transaction costs on solution uptake

Cross-system solution	Stakeholders involved	Most relevant transactions	Impact of transaction costs on solution uptake
Digitalisation	• Device suppliers/OEMs • Asset owners/operators • TSOs/DSOs • FSPs	• (B/HEMS) operation • (DERMS) dispatch and control of DER	Low
Local flexibility and EU balancing platforms	• Platform/market operators • FSPs • TSOs/DSOs	• Platform entry (for network operators and FSPs)	Low
Demand side flexibility and storage assets	• Asset owners/operators • FSPs • TSOs/DSOs • Platform/market operators	• Market exchange (tendering and trading) • Dispatch and control	Low-moderate
TSO/DSO cooperation	• TSOs/DSOs • NRAs • FSPs • Platform/market operators	• (Data exchange) data sharing authorisation • (Data exchange) data hub management • (Joint system operation) qualification	Moderate
Temporal/ locational network tariffs	• TSOs/DSOs • NRAs • Grid users • Energy suppliers	• Transmitting signals to grid users • Reaction of grid users to tariffs	Low-high
Microgrids	• DSOs • Asset owners/operators • Microgrid owner/operator • Grid users	• Dispatch and control • Independent management contract with network operator (optional; in case microgrid operator is different)	Moderate-High
Flexible network access	• TSOs/DSOs • NRAs • Grid users	• Grid connection agreements	High

The regulation level may be a leading factor in creating transaction costs for the deployment of cross-system solutions. The electricity sector generally has a high level of regulation, which is necessary for the functionality of critical infrastructure. On the other hand, more regulation can also lead to higher transaction costs. The cross-system solutions considered in this study mostly have a high or medium level of regulation over the relevant transactions. This regulation can be considered as a main driving factor for high transaction costs for many solutions. For example, strict data privacy and security considerations (while valid for various social and economic reasons) can greatly increase the costs of transactions related to data management, such as those of data sharing and data hub management in TSO/DSO cooperation. These impacts can appear throughout all categories of transaction costs, i.e. S&I, B&D, and P&E costs.

Different typical transactions for each solution have different levels of costs: the transaction costs of a solution may be driven by only one or two transactions. Transactions which are frequently occurring but for which there is not (yet) an organised market platform (and hence require individual negotiations, which are highly regulated and involve many parties), are leading to the highest transaction costs.

In comparison, network expansion and implementation of GETs have in general low transaction costs. TSOs/DSOs and NRAs have relevant experience with network planning and operation involving these classical solutions. Often, the main stakeholders involved work efficiently under a well-defined regulatory scheme. S&I costs for defining investment projects are in general rather low, as network operators can identify the needs and possible projects efficiently, while following established network planning rules. Nonetheless, there remain some information asymmetries on network development needs and on investment needs between NRAs and network operators, leading to some B&D transaction costs.

The deployment of cross-system solutions is impacted differently by transaction costs. Some solutions actually present low transaction costs. In these cases, transactions often exhibit lower information asymmetry and regulation over the transaction. For example, local flexibility platforms have multiple transactions with various factors that reduce transaction costs. The development of digital platforms for trading flexibility is primarily intended to lower information asymmetries and automate trading and settlement functions (including market actions by participants, market clearing and settlement, and accounting and billing). This is done through design choices in these markets, including the standardisation of data storage and communication protocols. Many of these factors can be identified in the example in the case study box further below. However, solutions which exhibit low transaction costs still often face difficulties related to other barriers (which are discussed in the next section).

Textbox 1 GOPACS and NODES Local flexibility platforms

GOPACS

The Grid Operators Platform for Congestion Solutions (GOPACS) is set up by the Dutch TSO TenneT and four DSOs and acts as a market intermediary platform. Its purpose is to support the coordinated market-based procurement of congestion management services by energy market operators participating in the intra-day markets.[91] GOPACS does not have strict pre-qualification requirements and validation processes, while there are no extra costs that market participants should pay besides the costs of participating in the ETPA market platform. Up to January 2024, 530 GWh of flexibility has been procured through the platform by TenneT (TSO) and almost 200 MWh by Liander (a major Dutch DSO).[92]

[91] ENTSO-E and Frontier Economics (2021) Review of flexibility platforms

[92] Data from GOPACS expenses report

NODES
NODES is an independent market operator launched in 2018 with several projects in Norway, Germany, and the UK. It provides a marketplace to trade local flexibility, enables DSOs to manage congestion and allows the coupling of the TSOs balancing markets to the local flexibility markets.[93] NODES has relatively flexible regulatory, commercial and capacity requirements for the FSPs.[94]

For reference, the English DSO Western Power Distribution (WPD) procured from the Intra-flex project 116 MWh of flexibility in August 2021[95]. According to the available data for 2023, the Norwegian electricity provider Agder Energi Nett procured 278 MWh of flexibility from the NorFlex project in the first 12 weeks of 2023.

- These platforms were designed to greatly improve available services for network operators, and to facilitate these transactions by standardising their trade. In addition to boosting liquidity in these markets, standardised transactions and accessible market information reduce information asymmetries between participants transaction costs.

For most cross-system solutions the transaction costs have at least a moderate impact on their overall uptake (see summary in Table 6). In most cases, various aspects of transactions create significant barriers to the uptake of cross-system solutions. The most prominent example are flexible connection agreements, where high transaction costs represent the main barrier. This is mainly due to the difficulties with developing and monitoring adherence to agreements for flexible connections, leading to high S&I and P&E costs. In the below box, we describe how the Danish NRA and energy industry addressed various issues to reduce the S&I costs within its development of a flexible connection agreement programme.

Textbox 2 Flexible connection agreements in Denmark

FCAs applied by the Danish DSOs[96]
Denmark has developed a FCA scheme at the DSO level. Following initial pilot cases between 2012-2014, in 2015 the Danish energy industry association *Green Power Denmark* developed, together with the NRA *Forsyningstilsynet*, a standardised approach to FCAs. In the latest version[97], the scheme has expanded to include both generation and demand assets. Some limitations on size exist: demand assets exclude households, due to high transaction costs along with limited benefits, and generation assets exclude assets below 1 MW capacity.

FCAs are allowed in both congested and non-congested areas. In return for a flexible connection, grid users receive discounts on the grid connection charge. The following design choices in this FCA scheme lead to reductions in transaction costs:

[93] https://nodesmarket.com/flexibility/
[94] European Commission, Joint Research Centre, Chondrogiannis, S., Vasiljevska, J., Marinopoulos, A. et al., Local electricity flexibility markets in Europe, Publications Office of the European Union, 2022, https://data.europa.eu/doi/10.2760/9977
[95] https://nodesmarket.com/intraflex/
[96] Thema Consulting Group (2022), Conditional connection agreements - A literature review.
[97] Green Power Denmark. (2022). Vilkår og betingelser for tilslutning med begrænset netadgang for produktionsanlæg

- Grid users are allowed to switch to a firm connection agreement if needed, based on an agreement with the DSO (i.e. dependent on costs and timeline)
- FCAs should not trigger additional network development, upstream of the individual connection and associated digital infrastructure. Moreover, in cases where this is needed, the grid user must switch to a firm connection agreement first.
- The DSO has some (non-binding) requirements for FCAs:
    - The DSO is expected to provide an estimate of the number of hours with curtailment throughout a year.
    - The FCA is expected to contain a thorough assessment and details on the uncertainties surrounding the grid access following the connection.
- For generation assets, the DSO must be able to control injection with its existing SCADA system.
- Grid users with FCAs can participate in TSO flexibility markets, but not in DSO flexibility markets. They also have full access to wholesale and balancing markets.

Across the cross-system solutions, there are differences in the significance of the different types of transaction costs.

Overall, **search and information (S&I) costs** are rather significant for most solutions; this is related to the fact that the specific benefits and costs for each party are usually not easy to establish, as compared to network-centric solutions for the same challenges. For example, this is especially the case for flexible connection agreements. On the network operator side, the short term changes in network usage cannot easily be connected to the long-term benefits of deferrals in network expansion. Thus, it can be hard to quantify the benefits of specific flexible connection agreements (and thus offer associated benefits to the concerned grid users, such as discounts on grid connection or access charges). On the grid user's side, the impacts and related costs associated with flexible connections are hard to estimate. Depending on the grid user, there may be difficulties in understanding how business operations (or in general, user utility in the economic sense) will be impacted by potential connection interruptions. Moreover, some flexible connection agreements are offered as a temporary alternative solution to a firm connection at a future date; this future date may not be fixed, which may give additional unclarity to the grid user. Thus, both network operators and grid users face significant difficulties in identifying and quantifying their respective benefits and costs from flexible connection agreements. Similar difficulties in CBA-like activities for other solutions lead to high S&I transaction costs.

Bargaining and decision (B&D) costs of cross-system solutions are in general also rather high, as contracting is often more novel than for network-centric solutions. A good example illustrating this issue is TSO/DSO cooperation, which faces high B&D costs across multiple transactions (data hub management, joint system operation, and definition of grid connection requirements, among others). Based on national and EU rules, network operators are generally required to cooperate on various topics. Nonetheless, varying and strict regulations on network operation, data privacy and security concerns, and non-harmonised requirements for grid management lead to network operators facing high B&D transaction costs for cooperating on various topics. The box below details a case whereby transaction costs for TSO/DSO cooperation were reduced.

Textbox 3 TSO/DSO cooperation: flexibility registers

Flexibility registers and the Belgium FlexHub initiative[98]

Flexibility registers are seen as an important tool in facilitating the procurement of flexibility services by multiple actors, including TSOs and DSOs. According to the OneNet project, flexibility registers "facilitate information exchange related to the overall flexibility market framework and conducts processes related to asset information management and flexibility verification and settlement.".

In essence, any flexibility market will require functionalities common with flexibility registers. Data hubs are another category of initiatives related to flexibility registers. However, according to OneNet only the Belgium FlexHub initiative managed by Synergrid meets all the requirements to be considered a flexibility register, including qualification and management of parties, access management and data sharing, and other features.

FlexHub is a joint initiative of Belgium TSO and DSOs, used to procure balancing as well as congestion management services. The operator of the platform manages contact details from market parties as well as the completeness and integrity of all data in the platform, provides the necessary data for the market parties, and aggregates provided flexibility volumes at the required level.

The **policing and enforcement (P&E) costs** are in general rather low for most cross-system solutions. This is related to two reasons: first, it is usually rather straightforward to evaluate whether a cross-system solution is satisfying the contractual requirements, as most solutions rely on digitalised and automated data flows and can be monitored, as long as relevant tools (such as smart meters) are available. Second, some cross-system solutions are rather novel, and the outcomes of enforcement actions (and/or the need for penalties) may not have become clear yet from existing evidence. This is especially the case for microgrids, where it is not clear yet whether a need for penalties exists, and in what form. Moreover, in the case of independent management of microgrids (i.e. by a party other than the network operator), the specific P&E activities of the network operator may not be clear.

4.4. Analysis of other barriers to the uptake of cross-system solutions

Within the scope of the barriers considered here, we find some common barriers across cross-system solutions. The impact of these barriers on the implementation of each cross-system solution is summarised in Table 7.

The first common barrier is **CAPEX bias** in some national regulatory frameworks for the recovery of network operator costs through regulated tariffs. The deployment of most alternative (GETs or cross-system) solutions can significantly be hindered by this issue, as this deployment either increases the OPEX share in the SO's costs (compared to classical solutions), and/or reduces the CAPEX investment needs and related remuneration for network operators. For example, flexibility procurement translates in an OPEX for network operators and may hence be discouraged over conventional network reinforcement for

[98] OneNet (2023) Flexibility register description and implementation D7.2

solving congestion issues.[99] A re-design of the concerned regulatory schemes for network operators' remuneration would be appropriate to resolve the CAPEX bias issue, such as moving towards TOTEX-based regulation.[100] Moreover, in the absence of appropriate incentives to reduce costs, network operators might prefer conventional solutions due to their higher total costs as it would lead to higher revenues, regardless of whether those are CAPEX or OPEX.

Table 7 Summary of other barriers for implementation of cross-system solutions

Cross-system solution	CAPEX bias	Other regulatory barriers	Financial barriers	Technical barriers	Social / Organisation al barriers
Digitalisation	High	Low	Very high	High	Medium
Demand side flexibility and storage assets	High	High	Medium	Medium	None/Low
Local flexibility and EU balancing platforms	Medium	Medium	None/Low	Medium	Low
TSO/DSO cooperation	None/Low	High	Medium	High	Low
Flexible network access	Medium	Medium	None/Low	Low	None/Low
Temporal/locational network tariffs	Medium	Low	None/Low	High	None/Low
Microgrids	High	High	High	Medium	High

A **second common barrier is related to technical or organisational aspects**. With the use of innovative alternative cross-system solutions, grids tend to be operated closer to their physical limits (which also applies for GETs). Network operators generally would then need to implement more monitoring and control activities, which represents an organisational/technical barrier towards the implementation of some alternative solutions.[101]

Other common barriers impact the deployment of cross-system solutions, including **unclear and nascent regulatory frameworks**. For less mature solutions, such as microgrids, the lack of a clear regulatory framework to support various aspects, such as contracting and agreeing on the roles of microgrid owners/operators, BRPs, NRAs, and network operators, can hamper the use of this solution. For some solutions, the lack of an enabling regulatory framework may hamper specific sub-solutions, while others are mature enough with clear and supportive regulatory frameworks. For example, large-scale storage faces less difficulty in this respect, while home batteries and EV smart charging still face hurdles for flexibility market access due to restrictive market entry/participation regulations.

Cybersecurity concerns are a common barrier across multiple cross-system solutions. With the increased need for cybersecurity measures in sensitive industries, the electricity grid and other critical electricity system components are under special scrutiny given the

[99] Ruiz et al. (2023) Regulatory Challenges for Energy Infrastructure—Do Electricity Distribution Remuneration Schemes in Europe Promote the Use of Flexibility from Connected Users?
[100] ACER (2023) Report on Investment Evaluation, Risk Assessment and Regulatory Incentives for Energy Network Projects
[101] ACER (2021) Position on incentivising smart investments to improve the efficient use of electricity transmission assets

increasing vulnerability of the electricity system. Cross-system solutions in the electricity system (such as digitalisation solutions) can expose the grid to more security risks or cause market interactions to be more vulnerable (such as with local flexibility platforms). These concerns can discourage network operators and NRAs from choosing cross-system solutions over classical ones.

The **lack of standardisation** is also a common barrier across multiple cross-system solutions. Cross-system solutions are particularly dependent on standards for various aspects, including market product or service designs, data, communication protocols. Standardisation is key to reduce the complexity and costs of transactions related to these solutions.

4.4.1. Role of NRAs and network operators

NRAs and network operators play a central role in the deployment of cross-system solutions including in reducing the level of transaction costs and other barriers for their deployment. The regulatory rules and procedures developed for network expansion have created regulatory frameworks and processes which were developed to be as efficient as possible, including for commissioning studies, planning, authorising and implementing projects, training personnel, and monitoring deployed assets and the overall system operation. **These frameworks can create friction when new cross-system solutions are being considered and/or deployed.**

Network development plans are a significant arena for NRAs and network operators to act in this regard. Within the planning methodologies and procedures, various elements and aspects impact the possibility for cross-system solutions to be considered for addressing grid challenges. For example, the requirement of NRAs on network operators to use deterministic planning models was previously a reasonable approach, but nowadays fails to account for the increasingly dynamic nature of the electricity system. Due to expected changes on the demand side (e.g., electrification of transport, heat and industrial processes), on the supply side (e.g., further deployment of intermittent renewable energy sources, including behind-the-meter) and the development of (small-scale) storage, there is a significant uncertainty in how the future electricity system might look. Deterministic network plans combined with strict (possibly outdated) grid performance criteria are assessed as leading to overly conservative investment plans and unnecessary costs.[102] Moreover, these practices can generally favour traditional over alternative solutions, the latter of which are in many cases highly flexible and responsive, and thus well-suited to address uncertainties.

The analysis of transaction costs reveals that, for all cross-system solutions, **there is a major role for NRAs/network operators to take suitable measures in view of reducing transaction costs,** as specific requirements, regulations, etc. may affect one or more aspects related to cross-system solutions and hence impact their transaction costs. For example, national rules may impact information sharing between different parties (the lack of or unsuitable rules can lead to information asymmetry), the number of parties needed in a transaction, and whether incentives for the different parties are aligned. We highlight

[102] Ruiz et al. (2023) Regulatory Challenges for Energy Infrastructure—Do Electricity Distribution Remuneration Schemes in Europe Promote the Use of Flexibility from Connected Users?

here multiple common threads identified in the previous analysis, and suggest actions that NRAs/network operators can take to reduce transaction costs.

Similarly, other barriers (regulatory, financial, technical, social, etc.) are to some extent resulting from national frameworks. NRAs and network operators should take suitable initiatives to remove or mitigate them in view of facilitating the deployment of cross-system solutions. In many countries, national frameworks still lead to regulatory barriers for most cross-system solutions, especially the CAPEX bias. This specific barrier for non-wire solutions is inherent to the most common revenue model currently employed in the EU for electricity (and gas) network operators. NRAs have the authority to develop new models that reduce or remove this bias. A commonly discussed alternative is TOTEX, where both CAPEX and OPEX costs and risks are considered for rate-of-return regulations. This is discussed further in chapter 5.

The lack of standardisation is also commonly repeated as a barrier and driver for transaction costs. More standardisation of transactions and market actions, such as for DSF, digitalisation, and balancing platforms, can greatly improve the deployment of cross-system solutions. In practice, **standardisation initiatives include rules set by NRAs or network operators** (while developed together with each other and other stakeholders) towards common standards for, among others, data storage and warehousing, communication protocols, and asset attributes.

Network operators have a significant role to play in addressing various technical barriers. These barriers generally relate to operational practices of network operators, which can differ greatly. Examples of operational choices relate to procurement practices for ancillary services (such as prequalification procedures), specific design choices in grid modelling, demand forecasting and optimisation, and grid reliability requirements. For example, probabilistic techniques can be used to mirror the inherent volatility of both load and generation. Thus, network modelling and monitoring can instead of deterministic results present stochastic calculations.[103] Improving the harmonisation of these operational practices is possible, both within national borders (via the NRA) and where appropriate and possibly also within the EU (via ACER, ENTSO-E and the EU DSO association, in cooperation with other organisations).

Lastly, **the joint role of NRAs and network operators in furthering TSO/DSO cooperation needs to be highlighted**. This is discussed in further detail in the section on TSO/DSO cooperation, and covers various aspects of cooperation including joint grid operation, data exchange practices, and cooperation on grid connections. Improving this cooperation also impacts the deployment of other cross-system solutions.

[103] Swiss Federal Office of Energy (2017) Smart Planning - Optimal Planning of Future Distribution Grids Under Consideration of Smart Grids and Smart Markets

5. Overview of and recommendations to enable cross-system solutions

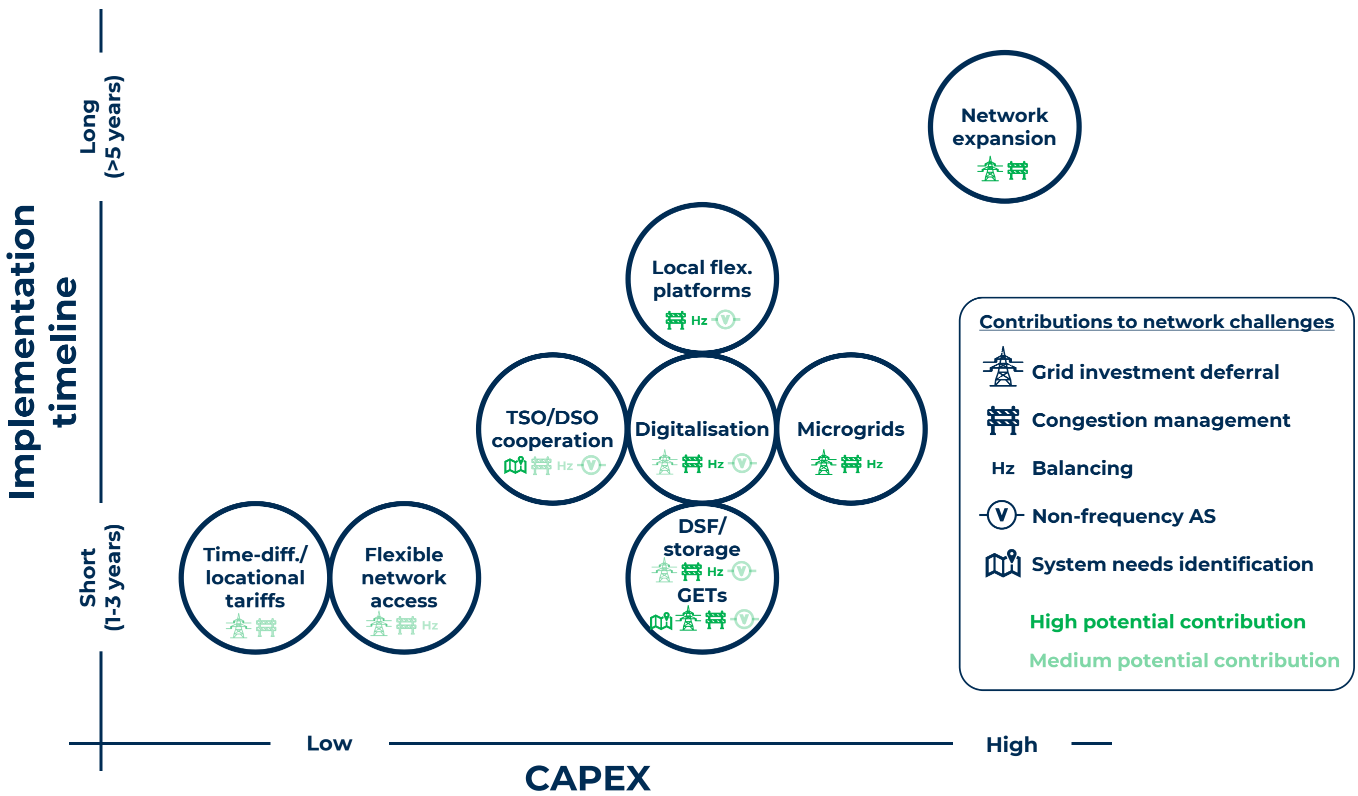
This chapter aims to provide an overview of the analysis on cross-system solutions conducted in the previous chapters as well as draw actionable recommendations to policymakers and regulators, network operators and other relevant actors. The chapter is structured as follows:

- 5.1 Comparative overview of the cross-system solutions
- 5.2 Recommendations on interesting specific solutions and good practices
- 5.3 Relevant regulatory framework
- 5.4 Broader policy and regulatory recommendations

5.1. Overview of cross-system solutions

Figure 14 below compares the implementation timeline, CAPEX and contributions to network challenges of each solution (including network expansion and grid-enhancing technologies). The figure must be considered with care given the challenges in assessing and comparing the solutions on a general level, but it gives an indication of the considered dimensions. The solutions' contributions to the main group of challenges are separated into 1) identification of system needs, 2) grid investment deferral, 3) congestion management, 4) balancing services and 5) non-frequency ancillary services. These contributions are further detailed in chapter 3.

Figure 14 Schematic overview of network expansion versus cross-system solutions



It is apparent that **alternative solutions can provide significant benefits compared to classical network expansion**, given their lower cost to address network challenges and faster implementation timeline. Furthermore, alternative solutions serve to meet network operators' flexibility needs, which network expansion does not address (although it does facilitate the integration of assets which meet those needs). Integrated network components and network operator-owner assets (when allowed by regulation) could be employed to meet some of these needs, but taking into account the unbundling rules, grid operators should mainly use sources from third-parties.

All assessed solutions present a **high potential to address network challenges at low or medium CAPEX with fast implementation timelines** (compared to network expansion). These solutions can be activated across a wide range of networks in the EU, and each can be directed towards at least some of the network challenges. Several solutions have a high potential to address particularly congestion management and balancing challenges, while fewer solutions have a high potential to defer grid investments or providing non-frequency ancillary services The most relevant solutions in this respect are microgrids and GETs, although other solutions such as DSF and storage assets are also able to contribute to network investment deferrals to some extent. Furthermore, an increasing number of solutions could provide non-ancillary services in the future as technologies reach commercial readiness. OPEX levels are not presented in the figure, as they were assessed as medium or low for all cross-system solutions, and in any case the economic advantage of these solutions compared to network expansion is mainly related to lower CAPEX levels (as OPEX levels of network infrastructure is also comparatively modest).

The "system needs identification" challenge is not addressed by most solutions. In order to improve the system needs identification, solutions need to provide network operators with a better understanding of the current state of the system and expected developments. Hence, only TSO/DSO cooperation and GETs are assessed as contributing to this challenge, which is anyhow in the scope of this study considered as a less important challenge. This does not mean that there is no room for market players having a more active role in the identification of system needs, including through better and earlier stakeholder consultation by network operators.

Complementary advantages of cross-system solutions

In addition to lower cost and/or faster implementation timeline, the solutions can present several other advantages, including:

- **Having an ex-ante impact on the challenges**, meaning that in addition to addressing existing challenges they help prevent network issues from appearing or at least increasing. This is because some solutions influence investment decisions of network users, thus having an impact on the drivers behind the network challenges. This is the case for example of innovations in time- or locationally-differentiated network tariffs, and digitalisation;
- **Leveraging of existing assets (at no or limited cost),** since for example time-differentiated network tariffs might incentivise existing users to manage their heating using a relatively cheap smart thermostat or to charge EVs at times of lower network (and energy) tariffs. Other solutions such as those involving the deployment of large-scale ICT solutions (local flexibility platforms, DERMS and

others) or for example bi-directional charging of EVs might utilise only new assets or require non-negligible investments to utilise existing ones;

- **Scalability,** as due to their comparatively low CAPEX per unit deployed and fast implementation timeline many alternative solutions identified (including GETs) can be scaled up across the EU. This is the case of solutions such as DSF and storage, microgrids, digitalisation (HEMS/BEMS) and GETs. Other solutions are rather deployed at a higher level such as local flexibility platforms, DERMS, and time-differentiated or locational network tariffs, and thus scalability is a less applicable concept. However, these latter solutions can present good economies of scale given the high fixed costs, meaning that they do benefit from wide application in each system;
- **Providing co-benefits from participation in wholesale markets,** since for example demand-side flexibility and storage solutions can also participate in these markets and derive a plurality of their total revenues from provision of flexibility to commercial parties (rather than to network operators only). This improves the business case of the solutions and can thus increase the pool of solutions available for addressing network challenges.

Advantages and disadvantages of specific cross-system solutions

Table 8 below summarises the main advantages and disadvantages of the selected cross-system solutions. The potential contributions of each solution to the network challenges are not listed, as they are presented in the figure above.

The solutions identified face a number of important barriers, related to high transaction costs as well as other barriers, as detailed in Chapter 4. **Most cross-system solutions have at least a moderate impact on their overall uptake due to transaction costs**. Overall, search and information efforts are rather significant for several solutions (as benefits and costs of solutions for each party are usually not easy to establish). Bargaining and decision costs are also generally high, given the lack of experience in agreeing contracts for the different novel solutions. In contrast, policing and enforcement costs are generally low, especially as it is usually rather straightforward to evaluate whether a cross-system solution is satisfying the contractual requirements.

The implementation of cross-system solutions is also significantly affected by other barriers, especially the CAPEX bias of many regulatory frameworks for remuneration of network operators, the lack of appropriate and clear regulation for enabling and promoting alternative solutions, and technical or organisational aspects given networks would typically be operated closer to their technical limits and require further monitoring resources and knowledge from network operators.

Table 8 Relevant advantages and disadvantages of cross-system solutions

	Advantages/disadvantages
Demand side flexibility and storage assets	+ Low CAPEX for some flexibility providers as investments are primarily driven by main utility provided by the assets (e.g. EVs) + Can leverage some existing assets such as EVs (for smart charging) and heating equipment + Scalability + Co-benefits to asset owners from participation in wholesale markets − High CAPEX for certain solutions e.g. requiring bi-directional chargers − Not all assets suitable for flexibility provision (e.g. electric trucks and buses due to high utilisation) − Low-voltage and potentially MV-connected assets require aggregation for provision of flexibility − Availability for flexibility provision constrained by user preferences
Digitalisation	+ Guides investment decisions of network users, having ex-ante impact on the challenges + Scalability (for e.g. HEMS/BEMS) + Economies of scale (for DERMS and some extent BEMS) for inclusion of new controllable assets + Increases visibility of the status of (flexible) assets to owners, network operators and other actors − Complex implementation with timelines of up to 5 years and risk of further delays − Direct benefits can be hard to assess given is enabler of multiple other solutions
Local flexibility and EU balancing platforms	+ Economies of scale for inclusion of new flexibility service providers + Co-benefits to asset owners from participation in wholesale markets − Complex implementation with timelines of up to 5 years and risk of delays − Direct benefits can be hard to assess given is enabler of other solutions
TSO/DSO cooperation	+ Economies of scale for expansion of initiatives to include further TSOs/DSOs and/or FSPs + Low transaction costs in case of connection-related activities − High transaction costs in case of data exchange and joint system operation − Complex implementation with timelines of up to 5 years and risk of further delays (for joint system operation) − Direct benefits can be hard to assess given is enabler of other solutions
Innovations in flexible network access	+ Enables connection of new/additional off-take or injection where lack of sufficient network capacity does not allow to offer a firm connection agreement + Low transaction costs in case only network code changes required − High transaction costs in case of individual flexible connection agreements − Can be employed by network operators to skirt on network investment duties in case of lack of adequate oversight by regulators
Time-of-use and locational network tariffs	+ Guides investment decisions of network users, having ex-ante impact on the network challenges + Time-differentiated access tariffs can be considered in combination with locational connection tariffs − High transaction costs if ICT systems necessary for provision of dynamic signals − Can provide conflicting signals to variable commodity prices, and overall signal may be dampened by tax and levy component of total energy prices
Microgrids	+ Scalability + Enables integration of DERs regardless of additional network benefits provided by microgrids + In case of DC microgrids, removes the need for inverters for individual DER assets + Lower power losses − High transaction costs with multiple parties within and outside of microgrid, particularly when DSO is not the operator of the microgrid

5.2. Applied cross-system solutions and good practices for consideration

This section identifies particularly interesting applications of the cross-system solutions and good practices for replication across the Member States. We highlight two particular classes of solutions which should be considered:

- **Low-hanging fruits,** namely solutions with a relatively fast implementation timeline, low CAPEX and low transaction costs, while providing substantial benefits. This category comprises particularly time-differentiated and locational network tariffs, some demand-side flexibility and storage assets, and GETs. Interesting DSF/storage solutions are demand response by MV- and HV-connected users, demand response of flexible e-boilers and heat pumps, and EV smart charging. Flexible network access approaches are also interesting, particularly if they only require changes in the network codes with limited interactions with grid users; otherwise flexible connection agreements can have high transaction costs;

- **Enabling solutions related to digitalisation,** such as local flexibility platforms, advanced distribution management systems, DERMS or TSO/DSO cooperation related to data warehousing and exchange. These solutions do not directly provide assets or infrastructure to address network challenges but are nonetheless crucial components for other solutions to function to their full extent. These enablers are characterised by important economies of scale, with low marginal costs for including additional flexibility providers, and are often a pre-condition to allowing the deployment of demand side flexibility, storage, and other solutions.

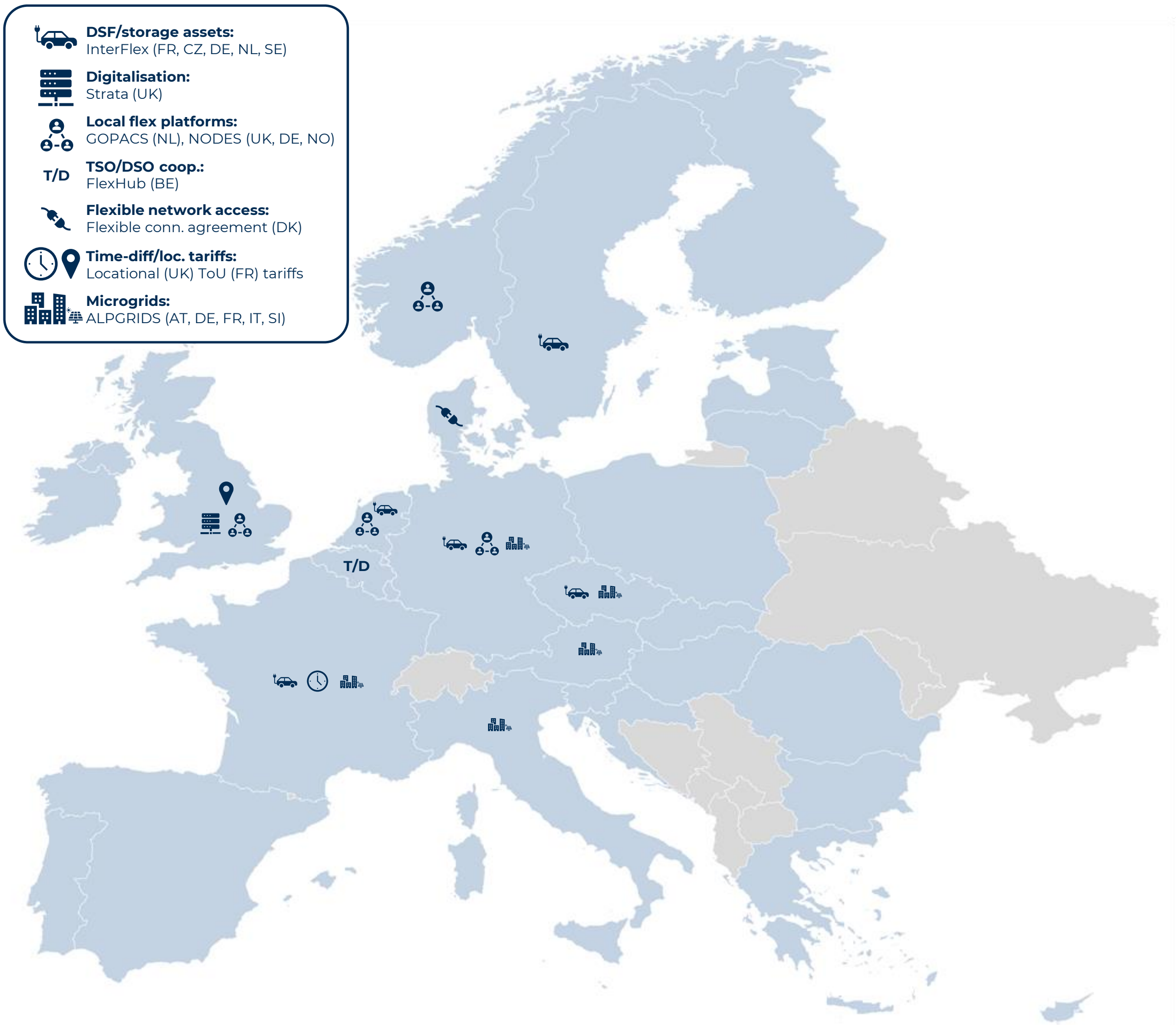
A number of good practices are furthermore identified for each solution – both general good practices as well as examples of application in Europe and elsewhere. Table 9 shows an overview of the main good practices identified for each solution, while Annex I fiches provides further details on each practice). They are concentrated in a few European countries, although this does not mean that interesting practices do not exist in other countries.

Table 9 Good practices identified per solution

Solution	Good practice (countries)	Good practice / relevant elements
DSF/storage	InterFlex (NL, DE, CZ, SE, FR)	Provision of DSF assets in 5 countries that demonstrated significant benefits in terms reduction of grid investment needs, improvement of power quality issues and reduction of peak loads.
Digitalisation	Strata (UK)	DERMS platform with several features which reduce transaction costs, including allowing for the precise control of flexibility assets, dynamic processing of information and system configuration, and automation of interactions with flexibility service providers (FSPs).
Local flexibility platforms	GOPACS, NODES	LFMs which reduce transaction costs and information asymmetries of the flexibility markets, with low entry barriers due to the low pre-qualification requirements and no extra participation costs.
TSO/DSO cooperation	FlexHub (BE)	Joint initiative of TSO and DSOs for the procurement of balancing and congestion management services, which reduces transaction costs by offering a 'complete package' by conducting the qualification and management of parties, managing access to the platform, verifying data completeness and integrity, and sharing data with the relevant actors.
Flexible network access	Flexible connection agreement (DK)	Contains several features which reduce transaction costs, including allowing users to switch to a firm connection based on agreement with DSO, and the communication by DSO of expected curtailment under FCA and of relevant uncertainties for grid access.
Time differentiated/locati on tariffs	Locational (UK) and ToU (FR) tariffs	FR: Clear communication of modalities of tariffs with differentiated approach per voltage level. UK: Locational signals to both generators and consumers, while taking into consideration distributional aspects (i.e. impact on household users connected to remote sections of the networks).
Microgrids	ALPGRIDS	Concrete policy recommendations and a replication package to effectively reduce transaction costs and facilitation of the adoption of microgrids

The UK stands out as a country where several good practices are deployed. The UK initiatives do not only concern pilot projects by network operators but also comprise established practices in how electricity networks are regulated, planned, and operated. While interesting practices could also be identified in other electricity markets, particularly the US, these are not explicitly detailed in the present report, mainly because liberalised US electricity markets can differ from EU ones in many aspects, for example regarding the use of locational marginal prices.

Figure 15 Good practices described in this study



5.3. Relevant EU regulatory framework

Due to the ongoing energy transition and the respective challenges that the electricity networks are facing, the EU has put in place several key regulations that play a crucial role in addressing the barriers identified in this report and support the development of a flexible electricity system. Some of the key provisions are mentioned below.

Electricity Market Design reform

The Electricity Market Design reform[104], officially signed off by the Council on 21 May 2024, focuses on two main pillars: incentivizing long-term contracts on the supply side and promoting flexible solutions on the demand, side particularly storage and demand response. The key elements of the market reform regarding cross-system solutions are:

- **Tariff methodologies**: Tariff methodologies should account for both capital and operational costs, which incentivizes system operators to invest in flexibility services to reduce the operational expenses. Tariff methodologies should support not only the use of flexibility services but also flexible connection agreements.

[104] See the final texts for the revision of the Electricity Directive and Regulation here

- **Report of flexibility needs**: Member States must report every two years on their electricity system's flexibility needs, including potential for demand response and storage, and set relevant goals.
- **Connection capacity transparency**: TSOs and DSOs are required to publish information about available capacity for new connections in their networks, including the possibility for flexible connection agreements in congested areas;
- **Flexibility support schemes**: Member States with capacity mechanisms, should promote non-fossil flexibility (such as demand response and storage). If these mechanisms fall short, additional flexibility support schemes can be introduced.
- **New peak shaving product**: Member States are allowed to implement a mechanism to contract the reduction of electricity demand during peak hours, in order to mitigate the system's stress and lower the costs for consumers.
- **Flexible connection agreements**: Regulatory authorities (or other competent authority) should develop a framework for FCAs, with specific requirements so that FCAs do not compromise network development and the offering of firm connection agreements to network users once congestions are resolved;
- **Decrease of minimum bid sizes**: Minimum bid sizes for day-ahead and intraday market trading will be reduced to 100 kW or less, in order to facilitate the participation of smaller, decentralized assets in all electricity markets.
- **Dedicated measurement devices**: System operators can use data from dedicated measurement devices in order to measure and settle demand response and flexibility services, which will ultimately increase consumer participation.

Energy Efficiency Directive (EED)

The revision of Energy Efficiency Directive (EED)[105] prioritizes energy efficiency in all relevant policy and investments decisions. In particular, Article 27 requires that Members States should ensure that TSOs and DSOS apply energy efficiency principles in network planning and development. Moreover, it requires NRAs to include in their annual reports a specific section on progress on energy efficiency improvements in gas and electricity infrastructure. Furthermore, regulatory authorities should remove incentives in tariffs that hinder energy efficiency and ensure infrastructure efficiency and facilitate demand response.

Network Codes and Guidelines

In addition to the EU electricity Directive and Regulation, several network codes and guidelines[106] have been developed to ensure the efficient operation and development of electricity networks. Relevant to the context of this study are the upcoming rules on demand response, and the Capacity Allocation and Congestion Management (CACM) and Electricity Balancing (EBGL) Guidelines, which facilitate the function of electricity markets, ensuring non-discriminatory access and efficient market operations.

Demand Response Network Code

On 8 May 2024 ENTSO-E and the EU DSO Entity have submitted a joint proposal for a Network Code on Demand Response. The aim of the network code is to further enable the

[105] Directive (EU) 2023/1791 of 13 September 2023 on energy efficiency and amending Regulation (EU) 2023/955 (recast)
[106] https://energy.ec.europa.eu/topics/markets-and-consumers/wholesale-energy-market/electricity-network-codes-and-guidelines_en

development of demand side flexibility in the EU markets, complementing legal provisions in the other regulations discussed in this section. Specifically, the proposed Network Code:

- "Facilitates access to electricity markets for all resources,
- Sets principles for the development of harmonised rules, and
- Defines market-based processes for selecting the most cost-efficient resources."[107]

Capacity allocation and Congestion Management (CACM)

The guideline on Capacity Allocation and Congestion Management (CACM)[108] is in force since 2015 and establishes binding guidelines for the implementation and operation of the EU-wide single market coupling in the day-ahead and intraday timeframes. The main elements of the regulation include:

- **Optimal definition of bidding zones**: TSOs and ACER must regularly analyse and, if necessary, review and propose changes to bidding zone configurations to maximize market efficiency, subject to regulatory approval.
- **Capacity calculation between bidding zones**: TSOs are responsible to calculate cross-zonal capacities for exchanges, using technical network parameters and coordinating within capacity calculation regions.
- **Allocation of cross-zonal capacities with market coupling**: Day-ahead market coupling is conducted via an EU-wide implicit auction, while intraday coupling involves continuous trading as well as daily auctions, both managed by Nominated Electricity Market Operators (NEMOs).
- **Management of residual congestions**: TSOs manage any remaining physical congestions through remedial actions like countertrading or redispatching, coordinating these actions and sharing the associated costs.

Balancing Guideline

The Electricity Balancing Guideline (EBGL) aims to facilitate the efficient exchange of balancing energy across EU borders by creating a unified market for balancing services (mandatory for balancing energy and voluntary for balancing reserves), ensuring harmonized market design and fair trading of balancing energy without market barriers. Consequently, TSOs can procure balancing energy and eventually capacity more efficiently, reliably, and cost-effectively. The main elements of the balancing guideline include:

- The establishment of balancing platforms, namely PICASSO, MARI and TERRE where balancing energy and system services are auctioned, cleared, monitored, and remunerated;
- The introduction of Frequency Containment Reserve (FCR) Cooperation, which is the primary control reserve platform and main cooperation initiative regarding balancing reserves;
- The IGCC as the cross-border imbalance netting platform.

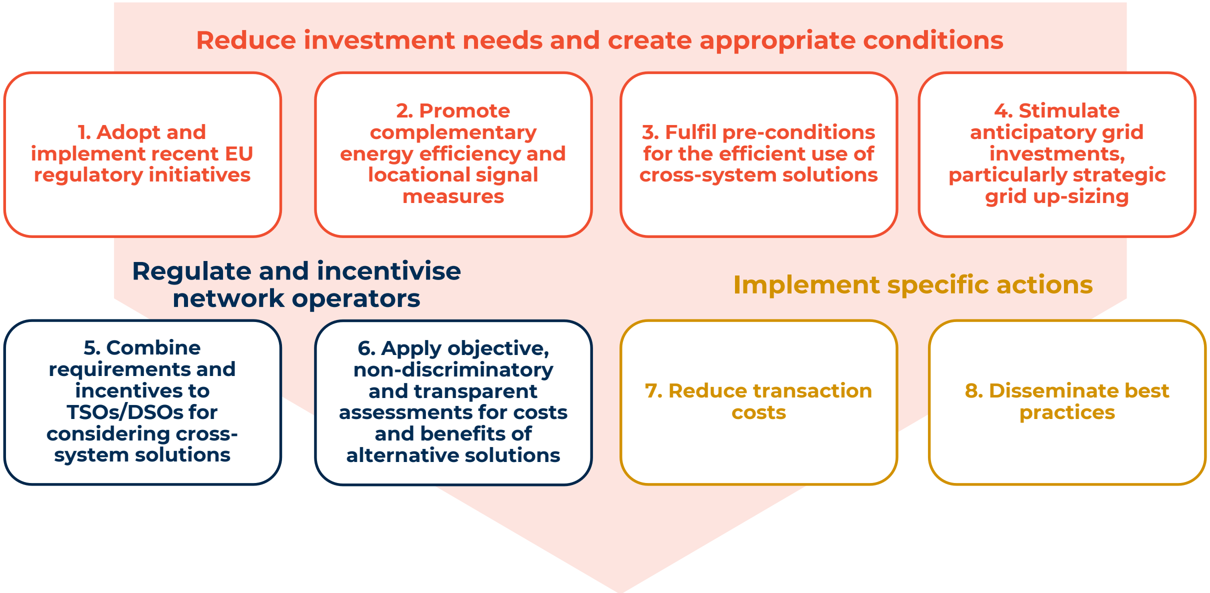
[107] https://www.entsoe.eu/news/2024/05/08/dso-entity-and-entso-e-submit-joint-network-code-on-demand-response/
[108] Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management

5.4. Policy and regulatory recommendations

This study analyses bottlenecks and investment challenges in the electricity grid and identifies and **compares selected alternative solutions within the same or another electricity sub-system** that can be implemented to defer or reduce grid investment needs. Other cross-system solutions could also be interesting, for instance hybrid heat pumps and power-to-X (hydrogen, heat), but these are not analysed here in detail. And even in the cross-system solution categories considered, there are many sub-solutions and specific applications across the EU and beyond which could not be covered in this short study.

This section presents **transversal policy and regulatory recommendations** which address multiple or all alternative solutions, grouped into three main categories, as illustrated in Figure 16.

Figure 16 Main recommendations of the study



Reduce investment needs and create appropriate conditions

1. Adopt (where applicable) and implement recent EU regulatory initiatives

The Clean Energy Package, the Electricity Market Design reform as well as the upcoming network code on demand response comprise several provisions which should significantly facilitate and accelerate the uptake of cross-system solutions in the EU, as indicated in the previous sections. National implementation of this new EU legal framework will require further efforts, and policymakers, ACER, and NRAs should pay close attention to implementing measures that properly address remaining barriers for demand response and other flexibility sources. The dedicated ACER monitoring of barriers to demand response and other DERs[109] as well as the new provision agreed in the electricity market reform requiring network operators to report on barriers to flexibility as part of the broader national flexibility assessments[110] are welcome steps.

[109] ACER (2023) Demand response and other distributed energy resources: what barriers are holding them back? 2023 Market Monitoring Report
[110] https://data.consilium.europa.eu/doc/document/ST-16964-2023-INIT/en/pdf

2. Promote complementary energy efficiency and locational signal measures

While alternative solutions can be an efficient approach to defer grid investments and address the other network challenges, there are complementary approaches which can be considered. As discussed in section 3.2, while energy efficiency is out of the scope of the present report, it nonetheless remains critical for minimising necessary grid investments. This comprises both energy efficiency measures to reduce demand as well as to reduce grid losses.

Network operators are required by the Energy Efficiency Directive to consider measures to reduce the latter, and there are many options available, from the use of high-efficiency conductors and transformers to the use of digitalisation. NRAs could exchange information on regulatory practices used to incentivise TSOs/DSOs to reduce their grid losses and use this information to update their national regulation where appropriate.

Energy efficiency measures targeting demand are not in the remit of the network operators themselves. But policymakers could cooperate with the network operators to identify and promote measures which have the largest impact on reducing peak loads, for example by providing additional financial support for end-users purchasing heat pumps if they are smart.

Concerning the specific challenge of managing rising congestion, there are many potential measures to be considered. Some of these are analysed in this study, specifically locational access tariffs as well as the procurement of congestion management services by network operators through local flexibility platforms. But there are other approaches which are out of scope of this report – for example the bidding zone review process, but also others which are gaining increasing attention, including locational connection tariffs and locational criteria in renewable energy or capacity mechanism auctions (which can be considered by national regulators and policymakers, respectively), and researching ways to increase the spatial granularity of wholesale market price signals (where the European Commission and ACER could play a role in coordinating and conducting the research).[111,112]

3. Fulfil pre-conditions for the efficient use of cross-system solutions

Policymakers and regulators should ensure certain pre-conditions are met to efficiently make use of the potential of cross-system solutions. This regards particularly the development of enabling digitalisation-related solutions by mandating and properly remunerating network operators (or regulated third-parties, e.g. those implementing and managing data hubs) to implement them. The Wired for Tomorrow report indicates that DSOs underutilise flexibility management digital solutions, and identified a number of regulatory barriers for further digitalising DSO investments and operations, including barriers for handling data, remunerating digitalisation expenditures, and having visibility on DSO roles regarding digitalisation.[113]

Moreover, some national authorities should reassess their decision not to opt for a large-scale roll out low-voltage electricity smart meters (if needed based on a new cost-benefit analysis, which also properly takes into account the indirect benefits provided by the participation of small grid users in ancillary services and electricity markets). Member

[111] JRC (2024) Redispatch and Congestion Management
[112] Neuhoff et al. (2024) EU power market reform toward locational pricing: Rewarding flexible consumers for resolving transmission constraints
[113] Accenture and Eurelectric (2024) Wired for Tomorrow

States that decided for a large-scale roll-out should closely monitor the actual progress and the efficient use of smart meters.

4. Stimulate anticipatory grid investments, particularly strategic grid up-sizing

Implementing all intra and cross-system solutions analysed in this study will still not allow to fully address the network challenges, nor eliminate the need for network expansion. Grid investments will remain necessary (often in combination with GETs in order to maximize the utilization of assets and minimize unwanted effects such as loop flows). Furthermore, significant investments in the EU will be required to replace ageing grids. These investments take place in a context of long lead times for development of electricity infrastructure.

Anticipatory grid investments (notably strategic up-sizing) will be necessary to deliver the EU's REPowerEU and Fit for 55 targets and should be facilitated by policy makers and NRAs. The EMD reform requires tariff methodologies to reflect anticipatory investments and to allow appropriate cost recovery. Approvals and permitting for anticipatory investments should be fast-tracked and streamlined to secure projects' go-ahead in advance of confirmed needs to enable demand's electrification and the timely connection of renewable electricity generation assets. For some Member States already facing significant structural congestion, this may be relevant to address forecasted network use growth towards 2040, while for other Member States with less severe congestion issues at the moment, anticipatory investments could help to connect additional assets in the shorter term. Stimulating anticipatory investments is supported by a number of stakeholders, and has been highlighted in the Grids for Speed report.[114]

Regulate and incentivise network operators

5. Combine requirements and incentives to TSOs/DSOs for considering cross-system solutions

National regulatory frameworks should (in line with the EU electricity market design) require the consideration of alternative options and authorise the recovery of the associated costs. As network activities are a (natural) monopoly, appropriate regulation is required, including for procurement of ancillary services, to ensure that non-wire solutions are properly considered as alternative to investments in grid expansion. According to the recent Grids for Speed study, in many Member States national regulatory frameworks still do not provide sufficient allowances for DSOs to realise anticipatory investments nor to contract grid-friendly flexibility[115]

Properly implemented TOTEX-based remuneration of network operators' activities remains one of the main avenues for incentivising the consideration of alternative solutions and should be considered by NRAs which do not yet employ it. To avoid increased complexity of their operations, TSOs/DSOs may at present still favour CAPEX based solutions rather than OPEX based alternative solutions, as investments are included in the RAB which represents a firm basis for their remuneration. As highlighted by ACER, "the options to potentially mitigate such CAPEX-bias, where present, include application of total-expenditure (TOTEX) regulation". But ACER also notes that "as also pointed out by NRAs, the implementation of such approaches faces several complexities, as they may

[114] EY and Eurelectric (2024) Grids for Speed
[115] EY and Eurelectric (2024) Grids for Speed

require larger changes in the regulatory framework to accommodate them."[116] Furthermore, not all TOTEX-based regulatory frameworks are the same, and attention should be paid to details such as the adoption of a fixed CAPEX-OPEX ratio.[117,118]

TOTEX-based remuneration is thus not sufficient to promote alternative solutions nor may be deployed in all jurisdictions. NRAs need to consider a combination of requirements (obligations) and incentives for TSOs/DSOs to implement alternative solutions. Various other approaches than TOTEX-based remuneration can be considered and often combined. Benefit-sharing schemes,[119] OPEX adders or bonus/malus-systems based on specific targets (congestion costs, curtailment costs, connection or construction times can be considered, among others).[120] Applying incentives calculated on the output generated by a TSO/DSO, rather than on its inputs (i.e. costs) could be efficient to stimulate implementation of alternative solutions. Such an output might be available connection capacity for additional offtake or the accommodation of renewable electricity infeed, for example. ACER recently highlighted the importance of incentives, particularly for the distribution level where alternative solutions are less frequently considered.[121]

DSOs and TSOs should quickly implement the new electricity market design provision requiring them to assess and publish the capacity available for new connections.[122] Such analyses are currently being published by grid operators in some Member States[123], and are a useful instrument for potential investors and authorities. These data and maps allow to compare the expected available grid capacity with market needs, define the (anticipatory) grid investment needs and consider intra- or cross-system solutions to cope with (temporary) grid capacity bottlenecks.

Finally, NRAs need to achieve a balance in the flexibility of the regulatory framework – overly prescriptive rules which for example strictly specify the solutions to be considered or the selection process, were shown in the US to be less successful than more flexible ones.[124] Flexible network development plans might also be better suited to handle the uncertainty regarding evolution of generation, storage and loads.[125] Moreover, there are a number of regional, technical and economic reasons for the methodologies for e.g. the distribution network development plans differing between Member States and even DSOs within the same country.[126] A wide range of (sub-)solutions should thus be eligible, for example by employing functional specifications (rather than prescribing eligible solutions), enabling the participation of both network-centric (such as GETs[127]) and cross-system solutions.

[116] ACER (2023) Report on Investment Evaluation, Risk Assessment and Regulatory Incentives for Energy Network Projects
[117] FSR (2024) Benefit-based remuneration of efficient infrastructure investments
[118] von Bebenburg, Carlotta; Brunekreeft, Gert; Burger, Anton (2022) : How to deal with a CAPEX-bias: Fixed-OPEX-CAPEX-share (FOCS), Bremen Energy Working Papers, No. 39, Jacobs University Bremen, Bremen Energy Research (BER), Bremen
[119] FSR (2024) Benefit-based remuneration of efficient infrastructure investments
[120] Brunekreeft (2023) Improving regulatory incentives for electricity grid reinforcement. Study for Autoriteit Consument en Markt
[121] ACER (2023) Demand response and other distributed energy resources: what barriers are holding them back? 2023 Market Monitoring Report
[122] Articles 7 and 10 of the provisional agreement on a reform of the electricty market design.
[123] For instance the Netherlands and Belgium
[124] RMI (2018) The Non-wires Solutions Implementation Playbook - a Practical Guide for Regulators, Utilities, and Developers
[125] Ruiz et al. (2023) Regulatory Challenges for Energy Infrastructure—Do Electricity Distribution Remuneration Schemes in Europe Promote the Use of Flexibility from Connected Users?
[126] CEER (2021) CEER Views on Electricity Distribution Network Development Plans
[127] CurrENT (2024) Recommendations for the deployment of DSO projects

6. Apply objective, non-discriminatory and transparent assessments for costs and benefits of alternative solutions

As the actual net benefits of the different cross-system solutions vary strongly depending on the local situation, TSOs/DSOs should compare the implementation costs and benefits case-by-case, and NRAs should critically review the proposed solutions. To avoid non-consistent approaches and underpin decisions with robust results, NRAs should establish objective and non-discriminatory methodologies to be used by DSOs/TSOs to undertake CBAs for alternative solutions. NRAs could establish a minimum list of alternative solutions to be considered by the TSOs, as is done in the UK.[128] As indicated above, the UK regulatory framework stands out as effectively promoting the adoption of alternative solutions by network operators.

The review of available data for this study has shown that significant limitations exist in the availability of public information on CBAs for alternative solutions. Moreover, even when CBAs are conducted, results are in some cases not publicly available and hence cannot be challenged. While information sharing may be constrained by the confidentiality requirements imposed by the concerned market operators, more transparency would improve comparability of solutions and lead to more cost-effective solutions for the network challenges. Thus, NRAs should develop rules regarding the disclosure of the results of CBAs for cross-system solutions and of the implemented projects' impacts. This concerns but is not limited to the procurement of flexibility through market-based or other approaches,[129] but also the procedures for deciding on digitalisation, TSO/DSO cooperation, flexible connection agreements and other mechanisms. This is in line with the findings of ACER, which indicate that identification at the national level of such investments and operational decisions by TSOs/DSOs and regulatory scrutiny by NRAs could be significantly improved,[130] and is also highlighted in other studies on the promotion of alternative solutions.

Implement specific actions

7. Reduce transaction costs

The transaction costs for implementing cross-system solutions are in general high. Unbundling requirements lead to a higher number of transacting parties and transactions and increased information exchange and asymmetry requiring more complex processes (although to a certain extent such processes still take place internally in vertically-integrated undertakings). As unbundling and TPA rules enhance competition in the energy market and ensure that electricity demand is met at least cost, they should as such not be questioned.

The number of transactions should hence not be reduced by re-bundling certain activities, but appropriate regulation is required to reduce the costs per transaction. Therefore, while furthering EU energy market functionality, policymakers and regulators should search for approaches to reduce transaction costs by standardisation of products and processes and by digitalisation. As most demand or supply related assets can participate in different markets, including local flexibility markets and (cross-border) electricity, capacity and ancillary services markets, harmonisation of products and processes, and mutual

[128] Compass Lexecon, CurrENT (2024): Prospects for innovative power grid technologies
[129] For a detailed discussion on procedures for DSO procurement of flexibility see CEER (2020) CEER Paper on DSO Procedures of Procurement of Flexibility
[130] ACER (2023) Report on Investment Evaluation, Risk Assessment and Regulatory Incentives for Energy Network Projects

recognition of prequalification results, can substantially reduce the transaction costs and enhance market liquidity and competition. Particular attention is required at the distribution level, where transaction costs can be higher due to the smaller size and greater number of assets deployed. Thus, NRAs can consider streamlined processes for authorising and remunerating alternative solutions based on representative or standardised projects.

Grid-enhancing solutions allowing to maximise the transport and distribution capacity of electricity across an existing system through a family of technologies including sensors, power flow control devices, and analytical tools, are in general an interesting solution that should be recommended for wide-scale implementation across the EU. As no third parties are generally involved in their implementation (apart from appropriate oversight by NRAs), the transaction costs are limited and the investment and maintenance costs are in general largely outweighed by the benefits they provide to the system. TSOs and DSOs should hence be mandated by NRAs to implement GETs where appropriate and NRAs should establish adequate incentive mechanisms for technology adoption.

8. Disseminate good practices

The insufficient availability of information on the net benefits of alternative solutions highlights the importance of sharing good practices. While policy and regulatory measures will need to be tailored to the specific regulatory frameworks, compiling good practices and where relevant even harmonising procedures could be highly useful. Such a repository could include information on criteria and processes for network operators' identification and CBA of alternative solutions as well as examples (with quantitative data) of implemented projects. The repository could also compile relevant studies on the topic.

To complement the compilation of good practices, regulators could commission the development of a handbook for promoting alternative solutions. This could use as inspiration the US-focused non-wires solutions implementation playbook,[131] but developing a handbook rather adapted for the EU context (where, in contrast to the US, for example TSOs and large DSOs are vertically unbundled, and different requirements apply to network operators regarding the consideration of alternative solutions).

[131] RMI (2018) The Non-wires Solutions Implementation Playbook - a Practical Guide for Regulators, Utilities, and Developers

5.5. Considerations for specific cross-system solutions

Finally, this study identified several **specific considerations for the implementation of the different cross-system solutions** which should be taken into account by policymakers, regulators and network operators. These considerations are presented in Table 10 below.

Table 10 Policy and regulatory considerations for the implementation of cross-system solutions

	Considerations for implementation
Demand side flexibility and storage assets	• Further revision of national regulatory frameworks and market rules should be stimulated to enable participation of small-scale DSF and storage, including via independent aggregators • Processes and transactions should be standardised and automated in order to reduce transaction costs as far as possible, at the national level and if possible EU level • Services/products procured by TSOs/DSOs should be harmonised/standardised to enhance competition and reduce transaction costs as far as possible
Digitalisation	• Comprises various initiatives, with network operators having greater direct control over DERMs and less so regarding B/HEMS. Implementation of DERMS should be weighed against other alternatives to reserve and activate DERs, such as flexibility markets • National authorities should reassess the decision in certain Member States not to roll out low-voltage electricity smart meters (if needed based on a new cost-benefit analysis) • Member States that already decided for a large-scale roll-out should closely monitor the actual progress and the efficient use of smart meters.
Local flexibility and EU balancing platforms	• Cooperation and participation in voluntary platforms should be stimulated and TSOs/DSOs should be encouraged to join existing platforms, when deemed efficient. Organised platforms can increase the pool of assets available to provide balancing and AS services, and allow transparent and market based price setting. • The operational and implementation (including transaction) costs can be reduced by using standardized products
TSO/DSO cooperation	• Given the variety of areas for coordination, it should be addressed first at a higher level through appropriate mandates to TSOs and DSOs for cooperation as well as establishment of an appropriate coordination platform (working group or other form) between network operators, with participation of regulator(s) • Higher levels of coordination in joint system operation can however lead to increased transaction costs, complexity and thus outweigh potential benefits, requiring a prior CBA assessing costs and benefits of different levels of cooperation • Specific good practices can be considered such as creation of a flexibility resource register, exchange of DER forecasts, and joint training of network operators' staff
Innovations in flexible network access	• Flexible connection agreements can in Member States with high congestion be considered as an appropriate temporary solution for a time period of e.g. 3 to max 7 years. If DSOs/TSOs can prove via a CBA that a specific flexible connection is in the medium to long term a more economic option than a grid expansion (e.g. in remote areas), the solution can be considered as definitive • Grid operators should be legally obliged to undertake the required investments to offer a firm connection agreement within a reasonable time period, unless the investment is not justified from a macro-economic perspective • Network operators should be legally obliged to provide a financial compensation to grid users that accept a flexible connection, at least above a certain level of curtailment • To avoid high transaction costs, the financial compensation could be based on the potentially missed revenue for the grid user, calculated on the basis of the maximum curtailment of load/injection foreseen in the contract
Time-of-use and locational network tariffs	• Member States should evaluate the (wider) use of differentiated grid tariffs to incentivise flexible use of the grid, and to indicate the most attractive zones and/or time periods for additional load or injection. . Such tariffs can be introduced first to some user categories, such as generators, industrial and commercial network users (possibly using an opt-in approach). These tariffs can then be expanded to all grid users (i.e. made obligatory) in subsequent stages depending on a positive evaluation of early results and a CBA for the expansion • Requires an assessment of interaction between temporal and locational tariff signals, as well as interactions with energy and tax & levies component of total energy prices. If flexibility is for instance solely driven by market signals, low electricity prices may trigger high simultaneous additional demand (e.g. from EVs, storage, etc.) leading to local peaks and possibly congestion that requires redispatching and additional grid capacity investments. Automated demand response programs should hence not only be driven by market prices but also by grid signals. • Predetermined time-of-use tariffs can give appropriate signals about the cost of network use depending on the load, such as in peak versus off-peak or winter versus summer periods. Such signals can give clear, and actionable information to grid users for investing in and flexibly utilizing assets. • In large bidding zones with regional demand/supply imbalances, location differentiated network tariffs can provide suitable locational signals for investments in generation or off-take (e.g. energy-intensive industries). Locational signals do not necessarily need to be integrated into network tariffs, but can also be provided by power market prices (e.g. separated bidding zones)
Microgrids	• Requires clear guidance on allowed participation of DSOs in ownership and operation of microgrids, since DSO-operated microgrids are a potential model particularly for rural settings • Microgrids could in some cases be considered as an appropriate option for energy communities and closed distribution systems

6. Annex I: Characterisation of cross-system solutions

In this annex we characterise the selected identified solutions to addressing the network challenges discussed in the report, providing the underlying data for the analysis conducted in the main chapters of the report.

The characterisation for each of the selected solutions comprises the following:

- **Description of the cross-system solution**, including for example which specific technologies and approaches are considered to fit within the broader solution;
- **Challenges addressed by the solutions**, with a focus on the network challenges detailed in chapter 2;
- **Examples of application,** with a focus on mature applications of the solution (i.e. commercial deployment);
- **Costs and benefits of the solution,** presenting quantitative data identified
- **Transaction costs** of the solution;
- **Other barriers** than high transaction costs which affect the deployment of the solutions.

We attempt to quantify the benefits and costs of each solution compared to the classical solutions. Data indicates the costs and benefits at EU, national or project level, as available in the literature. Additional data to the one presented in this annex which was identified at the end of the project was included in Table 4 in chapter 3, which thus presents the most complete overview of quantitative costs and benefits of the selected solutions.

6.1. Demand-side flexibility and storage assets solutions

6.1.1. Description of the solution

Demand-side flexibility asset solutions can modify their off-take and injection patterns based on external commodity or grid tariff (price) signals, or on explicit financial incentives for the provision of flexibility services. Such solutions are typically provided by small or larger electricity installations, which can be voluntarily and rapidly switched off/on or ramped up/down during a specific period of time. In the context of cross-system solutions for physical investments in electricity networks, in this report we refer for example to flexibility provided by electricity demand and storage assets such as **smart and bi-directional EV charging**, which can be integrated in energy systems for additional flexibility, providing a cost-effective power system resource. An additional service worth mentioning is **load-shifting** by end-users who use electricity for **processes and buildings heating**. The deployment of small-scale DSF solutions is relatively recent, especially via aggregators, and has yet to reach its full potential.[132]

Battery electric storage systems (BESS) include both stationary batteries (lead-acid batteries, li-ion batteries, flow batteries, etc.) and mobile batteries integrated in EVs that adjust its consumption pattern through smart charging, or take off electricity from the grid and can provide it back to the grid through vehicle-to-grid technology (V2G). As such, V2G solutions can be modelled as behind-the-meter storage, the charging and discharging of

[132] Trinomics and Artelys (2023): Power System Flexibility in the PENTA region – Current state and Challenges

which is limited by the number of EVs that are connected to the grid. A 2022 study assumes that 30% of EV chargers could be enabled for bi-directional charging in 2030 in the EU[133]. Demand-side flexibility can also be facilitated by thermal storage, which enables electric heating system owners to shift their load based on market or grid tariff price signals.

Local peaks in grid loads, caused by off-take (e.g. extremely low winter temperatures) and/or injection (high simultaneous output of PV and wind energy in summer days with low demand) can be reduced by these DSF solutions, and hence reduce or postpone the need for investments in grid capacity. The resulting flexibility service can be offered to the market (e.g. balancing responsible parties) and/or to grid operators, either individually by end-users and storage operators, or collectively via independent aggregators. This flexibility can also be used for other grid services such as voltage control and grid congestion management. An assessment on the activated flexibility by these sources (for the year 2030)[134] shows that the largest potential flexibility, in both directions, could be provided by residential electric heating, followed by EVs, then CHPs supplying district heating, and V2G.

These solutions are in particular enabled by **digitalisation** (discussed in section 6.2), **independent aggregators** and the **local flexibility platforms which enable aggregation** (discussed in section 6.3). Independent aggregators can offer flexibility to the market or grid operators, sourced from small loads as well as distributed generation and storage assets. Aggregating different electricity supply/demand profiles, including those from DSF and storage can provide high value to the system and dispatch their services in different electricity and ancillary services markets' timeframes if needed.

6.1.2. Challenges addressed by the solution

Solution	Examples of sub-solutions	Higher complexity to identify system needs	Limited grid connection capacity	Limited cross-zonal capacity & low utilisation	Increasing congestion in networks	Increasing balancing needs	Non-frequency ancillary service needs
Demand side flexibility and storage assets	Electric vehicles		D		T/D	T	D
	Stationary batteries		D		T/D	T	D
	Load shifting		D		T/D	T	

T/D: Transmission/distribution
High / medium / untested potential to address challenge

Large investment needs: By reducing peak loads, DSF solutions and storage can reduce investment needs in peak production capacity as well as network capacities and reinforcements to meet those peak loads. Distribution grids are particularly affected by the changing system environment, in which they need to be able to connect large amounts of decentralised RES and new (flexible) loads (including charging stations for EVs).

Limited connection capacity: While EVs are a relevant tool in addressing network challenges, an increasing number of EVs connected to the electricity grid require special attention from operators, as they represent an additional load (potentially leading to congestion) besides being a distributed flexible resource for grid services. The optimal management of the EV charging process as well as leveraging other DSF and storage

[133] SmartEN-DSF-benefits-2030-Report_DIGITAL.pdf
[134] *SmartEN-DSF-benefits-2030-Report_DIGITAL.pdf

assets is essential to overcome this double challenge and facilitate the connection of new assets in a context of congested networks.

Balancing: EVs can contribute to addressing balancing issues by enabling the shift of their charging process from peak demand (evening hours) to off-peak demand or peak supply hours. This time-shift has a significant positive impact on reducing peak network capacity needs. The beneficial effect is in particular enhanced when EVs charge during off-peak demand or peak supply hours and utilize V2G technology to feed energy back into the grid during peak demand hours, or when there is low supply from variable RES sources. The same can be said for stationary, behind-the-meter batteries that allow for shifting of their charging time to non-peak periods.

Thermal storage applications (coupled with e.g. electric heat pumps) allow users to adapt their off-take during a few hours per day, whereby the half-daily load required for electric space or sanitary water heating in buildings would be met, but consumption/off-take hours can shift overtime.

Congestion management: EVs are often the largest individual load in buildings, and due to their characteristics can contribute to alleviating grid congestion by serving as distributed resources that reduce the need for sub-optimal "re-despatching." Widely dispersed across the territory, EVs can provide grid operators with valuable opportunities to effectively address congestions in lines and nodes[135].

The mechanism involves EVs adjusting their charging/discharging profile based on requests from grid operators, possibly facilitated through a specific platform or market service provider. This modulation can occur either in advance, to avoid congestion that could be expected based on nominations submitted by Balancing Responsible Parties (BRPs) in the day-ahead time horizon, or during operation, based on adjusted nominations from BRPs or effectively occurring congestion.

EVs and V2G charging can also help in mitigating overloads on distribution grids by shifting their charging patterns from evening peak demand hours to off-peak demand hours, such as during the night, thereby avoiding additional stress on distribution grids and mitigating electrical and thermal pressures on electricity lines, and secondary substations.

This approach is particularly effective for home charging scenarios, preventing the accumulation of loads when vehicles return home, especially in conjunction with domestic appliances. The positive impact is achieved through either reshaping the vehicle charging curve (ensuring a more gradual power absorption over an extended period), or by entirely postponing charging[136].

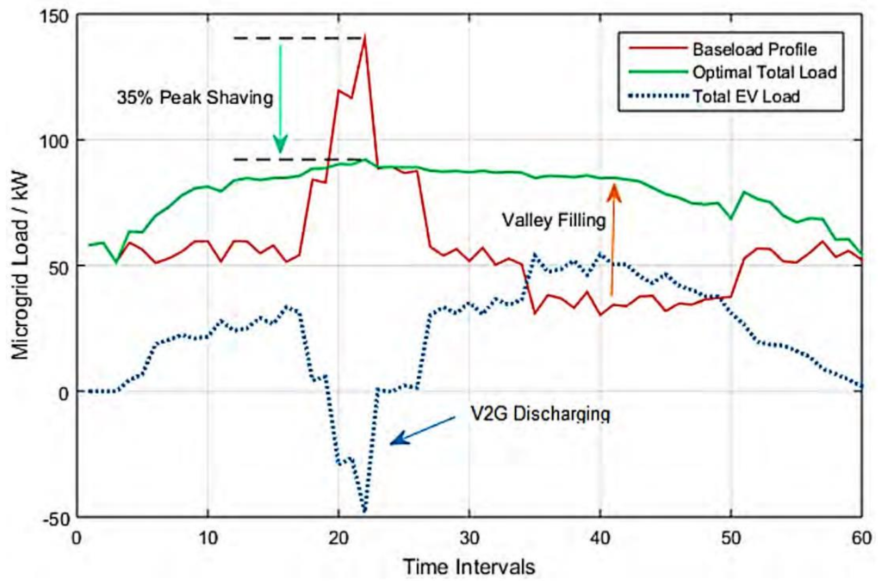
6.1.3. Example(s) of application

To test the **potential of bi-directional charging for congestion management**, a V2G demonstration project was spearheaded by the University of California, which showcased the efficacy of a smart charging algorithm in redistributing peak load by orchestrating power flows among 30 EVs (see Figure 17)[137]. Through the implementation of the smart

[135] ENTSO-E (2021): Position Paper on Electric Vehicle Integration into Power Grids
[136] To encourage this shift, dynamic or Time-of-Use (ToU) tariffs schemes can be introduced which reflect local grid constraints.
[137] Jones et. al (2021): The A-Z of V2G

algorithm and bi-directional charging, the original base load curve was flattened, with the algorithm successfully helped mitigate the peak load, reducing it by approximately 30%.

Figure 17 Peak load shifting and valley-filling by V2B



ENTSO-E's position paper[138] on the impact of EVs on the grid has outlined **several charging approaches/use cases[139]**, which exert varying effects on the power grid, with some network characteristics (urban or rural grids, connected loads, and grid operational features) introducing specific challenges. To assess grid impacts accurately, detailed analyses of specific grid segments are necessary, although certain common elements can offer a general perspective on potential grid issues associated with the different use cases. Three main conclusions can be drawn from this assessment:

1. Diffused EV charging may result in heightened power demand, particularly during peak demand hours with numerous connected loads, creating overloads on secondary substations or LV lines. Smart charging or other management approaches can significantly alleviate this issue.
2. High-power connections may necessitate the installation of new dedicated substations and connection lines, incurring extra costs and time.
3. Charging infrastructure designed for buses and trucks may require several MWs of capacity, potentially leading to the need for new lines or primary substations, emphasizing the importance of coordinated efforts between charging operators and grid operators to identify optimal locations and technical solutions.

Based on the above arguments, **we conclude that high-power connections for EVs (including trucks and buses) should not be considered as part of the solution to defer grid investments**, as they are not sufficiently flexible due to their high utilisation, and might create capacity issues rather than providing alternatives to grid investments.

[138] ENTSO-E (2021): Position Paper on Electric Vehicle Integration into Power Grids
[139] Public/private charging, pooled company vehicle fleets, fast charging, night charging of buses, highway charging for cars and freight transport.

To *expand the evidence base for similar conclusions and be able to attach precise values to DSF solutions, more demonstrations and attempts at estimating the benefits of different solutions are needed. The below textbox described one such approach.*

Textbox 3 pilot project to measure customer and system benefits of deploying residential DSF

In 2021, the California Energy Commission granted a $2 million contract to a company specializing in software systems and smart devices, to support the deployment and connection of 7,000 new and existing household smart energy devices. This initiative, enabling a total of 4 MW flexible capacity, has the potential to establish one of the most extensive distributed energy resource aggregation networks, utilizing residential devices in California. The project aims not only to reduce peak energy demand but also to offer dynamic balancing services and engage in wholesale price arbitrage, thereby contributing to the optimization and efficiency of the state's energy grid[140].

6.1.4. Costs and benefits of the solution

SmartEN and DNV (2023) have attempted to quantify the potential benefits of the full deployment of DSF matching this timeline (by 2030), estimating the adequacy benefit of DSF in this year to €2.7 billion[141]

Few studies so far have quantified DSF's potential in a systematic way, and the challenge partially lies in the absence of a common (EU-wide) methodology for assessing demand-side flexibility potential. This includes the need for an adequate baseline load reference. Due to this, DSF offerings, - especially those on a household level - are currently at risk of being undervalued in policy and economic planning, due insufficient understanding of the full range of its applications[142].

The main benefits of DSF are understood to be created in electricity wholesale markets[143], but there are other significant benefits, as described above, for network congestion, individual BRPs' portfolio and system balancing, and investments in grid infrastructure.

The most obvious **benefits related to the challenges faced by network operators** are:

- **Investment deferral and congestion management benefits** for both TSOs and DSOs, who benefit from the reduced need to reinforce grids, and a better grid operation, incl. reduction of traditional voltage regulators usage (less aging and maintenance costs). Avoided costs include investments into assets like transformers, protection elements, cables, and structures.[144] According to IEA estimates, demand-side flexibility could contribute to avoiding $270 billion (**€ 252 billion**) of investments in new electricity infrastructure at a global scale[145]. For the EU, deferred network investments would save an estimated **€ 11.1 – 29.1 billion** annually in the EU by 2030[146], including distribution grid investments.

[140] Packetized Energy awarded $2 million contract to help solve California grid challenges | Vermont Business Magazine (vermontbiz.com)
[141] Includes other DSF such as industrial DSR, electric heating, district heating etc. DNV (2023) 2030 Demand side flexibility: quantification of benefits in the EU
[142] The joy of flex: Embracing household demand-side flexibility as a power system resource for Europe (raponline.org)
[143] According to DNV (2023) 2030 Demand side flexibility: quantification of benefits in the EU, meaning forward, day-ahead and intraday electricity markets (explicitly excluding balancing markets / ancillary services)
[144] Profitability analysis on demand-side flexibility: A review - ScienceDirect
[145] Digitalization and Energy
[146] using a 'no-DSF' reference scenario assuming no flexibility or price responsiveness by these technologies,, and drivers for DSF being final electricity demand, adoption of EVs and RES capacity.

- **Savings in balancing markets** could mount to **EUR 262-690 million** by 2030 in the EU[147].

Concerned final consumers and EV/storage operators will also gain direct economic advantage if demand and storage flexibility is incentivized by well-designed wholesale markets, ancillary services procurement, and time-of-use or dynamic grid tariff schemes. Benefits to consumers were estimated to amount to **€71 billion per year** by 2030[148], although this must be seen as an upper limit with a full activation of the flexibility potential.

Other benefits include an overall reduction in energy prices, reduced generation capacity needs and a decrease in carbon emissions stemming from the activation of the different flexibility solutions.

Table 11 Benefits of DSF and storage solutions in the literature

Solution[149]	Region / case	Benefits
Smart + Bi-directional charging	EU-27	• Consumer savings and revenues **9.9 M€***
Stationary storage	EU-27	• Consumer savings and revenues **32 M€*** (only behind-the-meter)
Thermal storage/Load shifting	EU-27	• Consumer savings and revenues **76.3 M€*** (space and industrial electric heating)
Various DSF solutions	EU-27	• Avoided balancing costs **262-690 M€*** • Deferred grid investments **11.1-29.1 B€*** • Financial benefits **45 B€/year ****
Various DSF	DE	• Deferred grid investments **2,4 B€/year *****
Various DSF	Alberta, CA	• Cost savings of **7,600-10,000 $/kW******

*****In year 2030 based on SmartEN/DNV study (2023)
****** 2050 time horizon, representing potential benefits if flexibility, disaggregated to implicit and explicit DSF based on ACER (2013) study[150]
******* 2035 time horizon , focusing on distribution level benefits of DSF based on EWI (2021) study[151]
******** referring to the NPV of demand-side management solutions easing the peak electricity load, in different scenarios, incl. energy efficiency, demand response and smart charging, based on EEA (2020) study [152]

6.1.5. Transaction costs

While all transactions related to the planning, procurement, installation, operation and maintenance of flexibility assets have costs, we focus here on those relevant for the electricity system operators and concerned market operators. The nature, cost and complexity of these transactions depend to some extent on the ownership and the size of each asset. As the same transactions apply to various DSF solutions, we grouped them when analysing their transaction costs. The category includes, among others, the following sub-solutions:

- smart and bi-directional EV charging
- stationary storage
- load shifting (enabled by changes in electricity consumption or thermal storage

[147] DNV (2023) 2030 Demand side flexibility: quantification of benefits in the EU
[148] DNV (2023) 2030 Demand side flexibility: quantification of benefits in the EU
[149] Parameters differ by methodology and business case. Please consult the methodologies of the studies .
[150] DSF_Final_Report.pdf (europa.eu)
[151] EWI Kurzstudie | Ökonomische Bewertung des Nutzens lokaler Koordina-tionsmechanismen in der Stromversorgung (uni-koeln.de)
[152] Energy Efficiency Alberta (2020): Non-Wire Alternatives Study

There are multiple transactions within the lifetime of a DSF solution:

- Grid connection and access
- Market exchange (tendering, trading)
- Dispatch and control
- Accounting and billing
- Data management

All transactions involve significant interaction between the different actors in the electricity sector: most frequently the DSO (or TSO), who procures flexibility and decides on the dispatching times of the assets, and the concerned asset owners and/or Flexibility Service providers (FSP). Grid connection and access and activation of the concerned assets involves all these parties. Depending on the operation model, ownership can also impact the "dispatch and control" transaction. For example, if the service is operated by the owner itself and what the asset is used for may also be relevant.

Despite the actual connection costs being high, **grid connection and access** has the lowest transaction costs. Being a heavily regulated service, there is no significant search costs, or bargaining between the TSO/DSO and grid user (asset owner). Processes are fully automated, and costs are regulated. Along with installation and maintenance, the concerned assets are governed by long-term grid access contracts with low information asymmetry between the parties due to the regulatory environment.

The **market exchanges** involve qualification, tendering and trading, which processes are enabled by organised flexibility and marketplace platforms.[153] Procurement practices of TSOs/DSOs are highly regulated and also involve the owner/operator or service provider, as well as the concerned supplier/BRP. Standardised procedures have reduced overhead costs greatly, resulting in low S&I costs in mature markets. For the same reason, time and resources invested in bargaining or decision-making, are generally low, if noticeable at all. However, due to still prevailing complex and discriminatory administrative processes in some markets, especially the long prequalification processes[154], can cause a direct increase of S&I/B&D costs for market exchanges. The traded products can differ by DSF solution. For example, grid users equipped with thermal storage assets can usually only carry out downward regulation/load shifting, while stationary electricity storage or EVs can also provide upward flexibility.

Market functioning for these services can vary between countries, depending on how developed flexibility markets are. There is a medium level of information asymmetry between stakeholders, due to regulatory and market complexity, diverse expertise and unrevealed information on specific characteristics of flexibility assets. For example, players offering flexibility services do not hold information about their competitors, and themselves may not reveal their actual flexibility capabilities.

Dispatch and control require frequent interactions based on short or long-term contracts which govern the capacity provision and/or energy exchange. Similarly to market exchanges, there is generally a medium level of information asymmetry between the different parties in this transaction, particularly due to the dispatching preferences of the

[153] 210957_entso-e_report_neutral_design_flexibility_platforms_04.pdf (azureedge.net)
[154] According to the ACER MMR 2023 nearly half of EU Member States do not regulate the maximum duration of the re-prequalification process, which thus range from 2 weeks to 24 weeks in the EU

flexibility asset owner (or operator) and the needs of the TSO/DSO, which must be communicated to the FSP. S&I and B&D costs are medium, partially due to the complex or discriminatory qualification processes, and because data exchange needs to happen quickly to communicate dispatching schedules, and smart meters are needed for the activation and metering. P&E costs are generally low, as the penalties (in case something hinders delivery and activation, like network disruptions or supply fluctuations) of traditional flex markets are usually clear and well-automated.

Accounting and billing usually happens monthly, and has varying market functionalities depending on the landscape of relevant service providers, but has low transaction costs in general.

Data management of the dispatched flows and diagnostics lies with the TSO/DSO, with inputs required from the FSP or operator, but with low information asymmetry as it is in the interest of each party to have a transparent and robust data sharing system in place. All transaction costs are generally considered low due to fully automated processes.

InterFlex project

Given the infancy of small-scale DSF applications, a lot of use cases are still in the demonstration or pilot phase. The InterFlex project (2017-2019)[155] has investigated the technical and economic impact of selected smart solutions and the contribution of these flexibilities to grid operation, grid development and balancing, by equipping households with **solar PV, storage heaters, EVs, heat pumps, smart meters and connected control devices** in five EU countries[156]. The results of the study show that:

- **CAPEX savings can be realised** thanks to these technologies by postponing grid reinforcements. This was evaluated in the context of constraints caused by high variable RES shares in the electricity system and the wide-spread development of specific uses (e-mobility, electric heating);
- **Grid investments could be cut by almost a half** (46%) with a smart EV charging strategy;
- The German demonstration case showed that **local flexibilities contributed to managing power quality issues** whereby providing an alternative to forced curtailment measures;
- The Dutch demonstration results showed that based on future scenarios of high RES penetration, a typical household equipped with EV and heat pumps had the potential to **reduce its peak load by 58%** thanks to their flexibility potential.

The European Commission sponsored the *bridge* project that has investigated additional case studies on V2G applications that support grid stability and RES integration[157].

[155] Interflex-Summary-report-2017-2019.pdf (interflex-h2020.com)
[156] The Netherlands, Germany, Czech Republic, Sweden and France.
[157] *02 Vehicle to Grid.pdf (europa.eu)

6.1.6. Other barriers

The literature highlights **regulatory and market barriers as the primary impediment** to the widespread adoption of DSF and storage solutions as viable alternatives to traditional system solutions. ACER, in its 2023 MMR[158], had identified key barriers in this regard.

Among these barriers are the already mentions complex, lengthy, and discriminatory administrative and financial requirements for the qualification of DSF. Additionally, there is often an unavailability or lack of incentives, such as price signals or rewards, to provide flexibility. Restrictive requirements for providing balancing and congestion management services, as well as participating in capacity mechanisms and interruptibility schemes, pose further challenges.

Limited competitive pressure in the retail markets and public interventions in retail electricity prices also pose indirect challenges to the adoption of DSF solutions. ACER also points at other frequently occurring barriers in the electricity sector that impact distributed energy resources, such as insufficient electricity transmission capacity made available by TSOs for cross-border trade, or bidding zones' configuration not reflecting structural congestions. The 2023 MMR found that the current limited competitive pressure and/or liquidity in wholesale electricity markets also impacts the participation of smaller entrants, who face difficulties and high costs to find trading counterparts, leading to inefficient price formation. To conclude, these factors create a **complex market landscape that inhibits the widespread and cost-efficient deployment of demand-side flexibility assets.**

For storage solutions specifically, a significant challenge lies in an **inappropriate or inconsistent treatment of energy storage in national legal frameworks**, affecting the business case for storage and creating uncertainties and discrepancies in regulatory practices. This lack of coherence complicates market participation and may undermine the role of energy storage technologies in providing system services. There is an increasing need for improving transparency, cost-reflectivity, and non-discrimination in network tariffs, particularly to address concerns of double taxation and double tariffs imposed on storage and Vehicle-to-Grid (V2G) services. [159]

While considerable efforts have been made at the European level to harmonise regulations and promote the uptake of DSF technologies, **gaps persist in the implementation of EU directives and regulations at the national level**, such as Article 15 of the June 2019 Electricity market directive (EU/2019/944).[160] Next to properly implementing existing EU legislation, various provisions of the electricity market design reform recently adopted by the EU Parliament[161] will contribute to address regulatory inconsistencies across Member States, and contribute to the development of a cohesive and enabling regulatory framework for DSF and storage.

The lack of an enabling regulatory framework for V2G hampers the participation of EVs in bi-directional charging, particularly regarding energy ownership and imbalance issues. Additionally, current technical requirements for market access prove overly demanding for EV fleet participation, limiting the potential for widespread adoption of DSF solutions in the

[158] ACER MMR 2023: Barriers to demand response (europa.eu)
[159] REPORT on a comprehensive European approach to energy storage | A9-0130/2020 | European Parliament (europa.eu)
[160] calling for MSs to ensure that active customers are not subject to any double charges, incl. network charges: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32019L0944
[161] https://www.europarl.europa.eu/news/nl/press-room/20240408IPR20316/parliament-adopts-reform-of-the-eu-electricity-market#:~:text=The%20law%20will%20protect%20consumers,the%20terms%20of%20a%20contract.

transportation sector. Next to the relatively high purchase prices for EVs, this barrier further discourages using EVs for flexibility purposes. There is need for technical standardization and unified protocols to mitigate this barrier. **Data privacy aspects** sometimes add to the challenges of V2G adoption: stringent privacy regulation can limit the efficiency of the operator's user interface between stakeholders (in the case of EVs: the aggregator, charge point operator (CPO) and charging session (CS)). The aggregator needs the permission of the driver to start the charging, and in some cases validating this request is not taken into account when designing user interfaces. [162]

As technical issue, the limited roll-out of smart meters in some EU Member States

Lastly, **inertia in modelling for system purposes** must be considered as a key technical barrier: a SmartEN study from 2021[163] suggests that there is a bias in current modelling practices (pointing at ENTSO-E's TYNDPs and Resource Adequacy studies) resulting in under-valorisation of DSF potential and consumer benefits. The report states that despite the 2022 TYNDP considering more technologies like storage, EVs or heat pumps, these are still evaluated from a narrow perspective and their DSF potential is not sufficiently considered. These biases in modelling methodologies result in an underestimation of the DSF potential and benefits of an increasing engagement from energy consumers and prosumers in flexibility services provision. The same comment may apply for the 2024 TYNDP, based on the 2024 Scenarios storylines[164]. Ember also points out[165] that TSOs often do not use the most forward looking scenarios which would reflect ongoing policy discussions and trends in key technology deployment (like DSF).

Table 12: Barriers for demand side flexibility and storage

Barrier type	DSF and storage
Regulatory	• CAPEX bias favours ownership of assets by network operator, rather than third party • Complex requirements for qualification of DSF • Lack of incentives for TSOs/DSOs to consider non-wire alternatives • Limited competitive pressure in retail markets • Energy storage not adequately and coherently treated in national legal frameworks • Further transparency, cost-reflectivity, and non-discrimination needed in network tariffs – double taxation and tariffs for storage and V2G services • Current regulations still represent a barrier for participation of new (small) actors in flexibility schemes[166] • V2G regulation not clear on energy ownership, imbalance issues • Current technical and dimensional requirements for market access too demanding for EV fleet participation • Bias in current modelling practices resulting in under-valorisation and underestimation of DSF potential and consumer benefits • Bidding zones' configuration not reflecting structural congestions • Data privacy aspects
Financial/economic	• Cost of EVs posing a barrier for widescale adoption of flexibility offered by EV batteries
Technical	• Interoperability issues for EV charging infrastructure due to varying standards and communication protocols

[162] *02 Vehicle to Grid.pdf (europa.eu)
[163] *smartEn-Position-paper-methodologies-FINAL.pdf
[164] TYNDP 2024 Scenarios Storyline Report, July 2023 (entsos-tyndp-scenarios.eu)
[165] *Short_Transmission Grids Report (ember-climate.org)
[166] ENTSO-E (2021) Position Paper on Electric Vehicle Integration into Power Grid

6.2. Digitalisation solutions

6.2.1. Description of Solution

Digitalisation solutions in this context refer to investments in and optimal use of various digital assets that can enable and improve both network management and energy management by grid users (at both supply and demand side). Thus, the distinguishing feature of this category, as compared to DSF and storage, is the enabling role of this digital infrastructure as compared to individual DSF and storage assets.

There are a wide variety of devices that can be considered in the context of digitalisation solutions. To cover the most important ones, we consider the following in the analysis:

- **Home and office digitalisation devices**, including devices for building and home energy management systems (BEMS and HEMS), smart meters, unitary device controls (for devices such as heat pumps). Smart/bi-directional chargers for EVs may also be considered here, but as specific physical infrastructure they are considered in the DSF and storage solution category;
- **Industrial load devices**, particularly digital management of hybrid heating systems and other loads;
- **Energy resource management systems,** which can enable electricity generation, storage, and consumers' assets to be directly controlled by grid operators and flexibility service providers, to manage needs for various grid services. At the TSO level, renewables can be remote-controlled for real-time optimisation of their operation, possibly reducing curtailment needs. For DSOs, Distributed ERMS (DERMS) are integrated into advanced distribution management systems and allow for better management of resources at the edge of distribution grids to ensure grid stability and reliability;
- **Grid monitoring and control devices**, including both existing and more recent advances in supervisory control and data acquisition (SCADA) assets to enable better monitoring and control of distribution and transmission grids. These also include advanced distribution management systems (ADMS), which unify state analysis, switching, outage management, and planning, based on a single as-built model of the distribution system (usually based on a geographic information system).

While each of these solutions connect to different assets and parts of the electricity system, their common attribute is that they enable some form of energy and/or grid management. In the case of the last bullet point, grid monitoring and control devices directly allow for more efficient grid management, allowing to better use the available capacity, and hence reducing the investment needs in grid reinforcements.

However, as is the case for advanced distribution management systems more broadly, while novel advanced grid monitoring and control devices can be implemented unilaterally by network operator (with investments authorised by regulators if applicable) without further involvement of market parties. Hence, such network-focused solutions are not cross-system and not analysed further in the context of this study.

6.2.2. Challenges addressed by the solution

Solution	Examples of sub-solutions	Higher complexity to identify system needs	Limited grid connection capacity	Limited cross-zonal capacity & low utilisation	Increasing congestion in networks	Increasing balancing needs	Non-frequency ancillary service needs
Digitalisation	Home energy management system		D		T/D	T	
	Building energy management system		T/D		T/D	T	T/D
	DERMS		T/D		T/D	T	T/D

T/D: Transmission/distribution
High / medium / untested potential to address challenge

As enablers, digitalisation solutions address a variety of challenges connected to multiple cross-system solutions. These are:

- **Increasing needs for balancing services and non-frequency ancillary services**: enabling the implementation of various flexibility resources at supply and demand side, providing more service offerings for provision of balancing and other ancillary services.
- **Large grid investment needs and long lead times for network reinforcement**: by directly addressing the underlying needs, digitalisation can enable flexibility solutions to overtake (or postpone) the need for grid expansion.
- **Limited grid connection capacity and congestion management**: enabling extra flexibility assets allows for less congestion on the grid, which would in turn increase the availability of grids to take up new and/or enlarged connections.

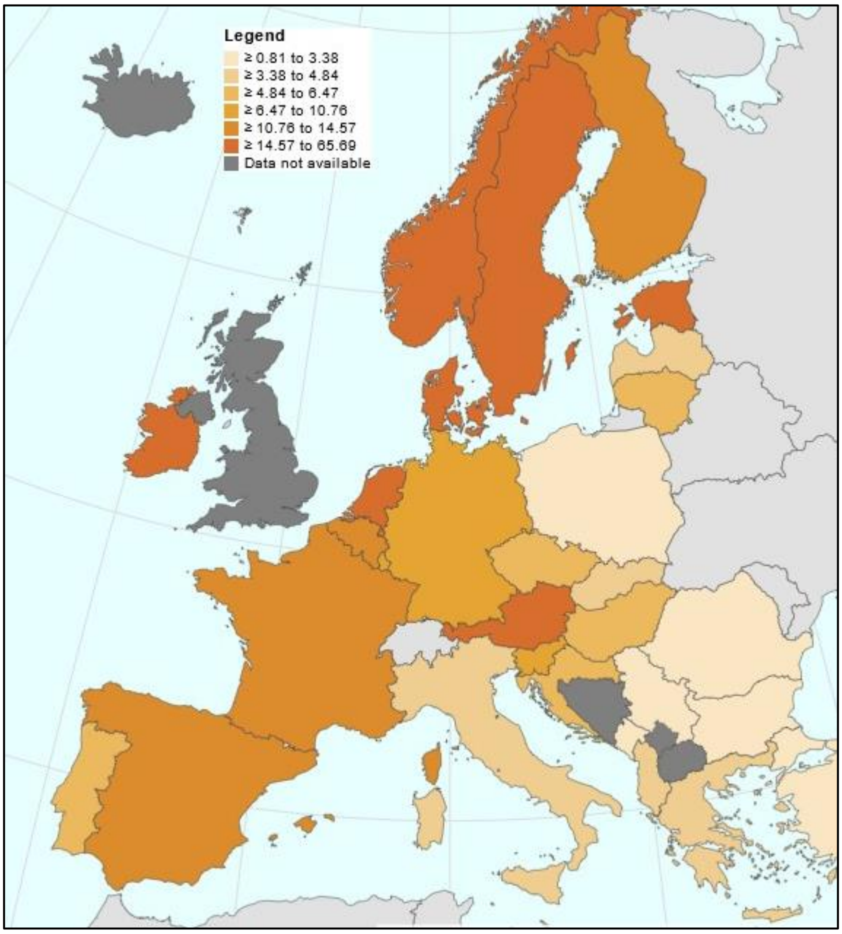
6.2.3. Example(s) of application

BEMS refers to the digital devices used for monitoring and control of a (commercial) building's electrical and mechanical equipment, including heating, ventilation, and air conditioning systems. HEMS refers to similar uses in a residential context, e.g., for residential heat pumps.

HEMS adoption in Europe is increasing. While more advanced systems controlling multiple devices are less widespread, the use of smart thermostats and other energy management devices is high in many Member States. The percentage of households with internet-connected thermostats, energy meters and devices for energy management is exceeding 10% of households in multiple Member States[167], with a maximum of 68% of households in the Netherlands, as shown in the figure below.

[167] BE, DK, EE, IE, ES, FR, LU, NL, AT, FI, SE

Figure 18 Households Internet-connected thermostat, utility meters, lights, plug-ins or other internet-connected solutions for energy management for their home (Eurostat isoc_iiot_use)



6.2.4. Costs of the solution

DERMS

When considering CAPEX and OPEX figures for DERMS, we use information reported in the Digitalisation of Energy Flexibility report from two US utilities who used DERMS. Considering the similarity in suppliers of DERMS equipment, figures are not expected to be significantly different in Europe. These two utilities are the National Grid Rhode Island and the Long Island Power Authority.[168]

Assuming a 15-year lifetime, total annualised CAPEX is about 860-1200 €/MW-year, and total annual OPEX is about 140 €/MW-year, leading to a total annual cost of ownership of 1000-1340 €/MW-year.[169]

BEMS/HEMS

At the higher end, costs for BEMS are set based on installing and operating control boxes at building premises. the Digitalisation of Energy Flexibility study report total cost of ownership for DSO operators of BEMS systems equalling 2230-2650 €/MW-year (depending on extra software need and costs). This range estimate comprises of 84%

[168] McKinsey et al. (2022) Digitalisation of Energy Flexibility
[169] McKinsey et al. (2022) Digitalisation of Energy Flexibility

annualised CAPEX costs, with the remainder from OPEX (which is also dominated by fixed costs).[170]

At the lower end, DSOs may be able to directly control and synchronise activities with BEMS with no need for extra hardware or software. This would lead to expenditures of close to zero.

Costs for HEMS are found to be higher, due to lower economies of scale from building size. Total cost of ownership is calculated as 5200-6200 €/MW-year, impacted by similar factors as with BEMS. 84% of costs are annualised CAPEX costs, with the remainder from OPEX. Similar to BEMS, HEMS may not require any additional hardware or software and costs may actually be close to zero for some installations.[171]

6.2.5. Benefits of the solution

DERMS

Benefits from the utilisation of DERMS are more difficult to measure than costs. There are multiple benefits to the use of DERMS. For grid operators, DERMS (further) enables various forms of active grid management, including Volt/VAR optimisation and control, power quality management, and power flow management. These benefits fit essentially into flexibility services needed by DSOs, such as for voltage regulation. For consumers, DERMS's optimisation of grid operations would lead to better infrastructure efficiency, reducing investment needs and grid costs in the long run.[172] Two estimations of these benefits are:

- Better use of grid capacity and reductions in investment needs. Scotland's Smarter Grid Solutions estimated that using DERMS across all 6 DSOs in the UK can save 250 M£.
- Reductions of voltage violations. These reductions would vary massively depending on grid topography and assets; as an indicative value, PG&E in California, the US, reported on a 95% reduction in costs due to voltage violations when a DERMS was implemented.[173]

BEMS/HEMS

The primary benefit of BEMS/HEMS is enabling the use of HVAC systems towards flexibility uses. Thus, much of the benefits following from BEMS/HEMS fall primarily within the category of DSF and storage solutions. We nonetheless report on these here to illustrate the potential benefit of digitalisation, if the underlying required DSF assets are available.

The Digitalisation of Energy Flexibility study calculates the potential benefits of these systems, finding that up to 38 GW and 40 TWh of flexibility can be provided by 2050 by BEMS, and 8 GW and 26 TWh by HEMS.[174] Capturing these benefits is dependent on also enabling (via legislation) the possibility of aggregators and their non-discriminatory access to flexibility markets. The same study also provides an estimation of revenues if this flexibility was traded on wholesale markets: 7 189 €/MW-year.[175] However, it is worth noting that ramp rates for devices connected to BEMS are usually far better performing that what is required for wholesale market trading - HVAC devices can in many cases ramp up and

[170] McKinsey et al. (2022) Digitalisation of Energy Flexibility
[171] McKinsey et al. (2022) Digitalisation of Energy Flexibility
[172] Guidehouse (2020), Asset Study on Digital Technologies and Use Cases in the Energy Sector
[173] EnTEC (2022), Digitalisation of Energy Flexibility
[174] EnTEC (2022), Digitalisation of Energy Flexibility
[175] EnTEC (2022), Digitalisation of Energy Flexibility

down quickly enough for participation in ancillary services markets or as other higher-value services, which may have higher revenues per MW or MWh of flexibility. Thus, this calculation of benefits can be considered a lower bound.

6.2.6. Transaction costs

BEMS/HEMS

There are multiple transactions within the lifetime of a BEMS or HEMS system:

- Purchase
- Installation
- Operation
- Maintenance and repairs

While all transactions have costs, we consider here those relevant for the electricity system. For B/HEMS, the operation step is the only one with direct involvement of the electricity system's other actors. Namely, operation of BEMS/HEMS involves the building owner, the B/HEMS supplier, the TSO/DSO, and the FSP.

B/HEMS operation involves continuous interactions based on a long-term contracts which govern the interactions. There is generally a medium level of information asymmetry between the different parties in this transaction, particularly between the preferences of the building owner (or operator) and the needs of the TSO/DSO, which must be communicated via the FSP. Due to the involvement of DSF and the actions of network operators, these transactions are somewhat regulated. There are in some markets multiple FSPs that can facilitate the operation stage, but in most markets, there are very limited options, or none at all.

Transaction costs for B/HEMS operation differ, depending on cost category. As mentioned, most regions and markets currently present few options for operation (i.e. FSPs and/or network operators willing to operate assets for flexibility provision), so S&I costs are perceived to be high. We consider B&D costs to be low: where interactions for flexibility provision can exist, they are often standardised to reduce costs (e.g., by the creation of subscription forms by FSPs due to the need for scale for flexibility services). P&E costs are also low: given data provision by the B/HEMS and existing standardisation practices for these devices[176], the operation of the device can be monitored to follow contracted expectations easily and can be automated.

DERMS

Transactions for DERMS systems include:

- Procurement and licensing of DERMS hardware and software
- Installation
- Maintenance and repair activities
- Activation of DERMS assets

All transactions involve significant interaction between actors in the electricity sector and are considered here. These transactions all have on one side the DSO, which utilises DERMS. Procurement practices of DSOs are often highly regulated and involve also the DERMS

[176] SmartEn (2023), Data exchanges for the system integration of consumers: assessment of available standards and protocols.

provider. The activation of DERMS assets also relates to the owners of flexibility assets, the FSP, and sometimes also the TSO.

Procurement and licensing of DERMS from providers can be considered a one-off transaction. While DERMS is rather novel, the European market for DERMS already has a few providers from the traditional power sector technology providers, including Hitachi ABB, Siemens, GE Vernova, and Schneider Electric, and some newer startups, such as Smarter Grid Solutions (UK-based; acquired in 2021 by Mitsubishi Electric). As DERMS and ADMS products are increasingly modular, there is less vendor lock-in for DSOs based on the OEM chosen for ADMS.[177] Most DERMS contracts are developed as a long-term negotiated agreement, with the possible benefits of DERMS being difficult to ascertain in advance (i.e. some information asymmetry). Procurement and licensing practices of network operators are highly regulated. Considering these aspects, both S&I and B&D transaction costs are perceived to be high. P&E costs are however low, as this is a one-off interaction with clear and measurable outcomes.

The installation and maintenance and repair activities for DERMS are generally done also by the DERMS provider. The transaction costs from these activities are not significantly impacting overall transaction costs for DERMS.

Activation of DERMS assets is carried out by the DSO, but also would involve the owner and/or operator of the asset (distributed generation, storage, EV, etc.), along with the FSP and (in some cases) the TSO. There is some information asymmetry between these parties, especially for assets such as EVs and (small) storage. Activations would be continuous throughout the period in which the asset is available to DERMS; depending on the region, a market may facilitate the activation's transaction, or a long-term contract may exist between the asset owner and DSO. With such a market, S&I and B&D costs are low for these transactions. However, P&E costs can be higher, as it may be unclear what penalties should be set for lack of suitable response to activations by DSF assets. It may also be unclear whether a lack of activation is due to the DERMS system or due to the underlying asset.

Smart Grid Solutions and the Strata platform[178]

Smart Grid Solutions is a Scotland-based maker of DERMS, with high uptake in the UK market. Their Strata platform holds multiple benefits for the management of the grid, especially by increasing capacity for new DER generation to be connected to the grid.

There are multiple factors in the Strata platform that contribute to reducing transaction costs, especially for the activation of flexibility resources.[179] These include:

- Allowing for a variety of different assets to be connected to the grid. This is also facilitated by using the OpenADR standard for behind-the-meter demand response assets.
- Giving a much more precise and detailed control of flexibility assets at the edge of the grid, for example by DSOs.
- Including multiple benefits in terms of data management, leading to easier management of system reliability and allowing for value stacking.

[177] McKinsey et al. (2022) Digitalisation of Energy Flexibility
[178] https://www.smartergridsolutions.com/media-center/case-studies
[179] https://essmag.co.uk/smarter-grid-solutions-tackles-flexibility-from-clean-energy-with-launch-of-anm-strata-3-1/

- Allowing for dynamic processing of information and system configuration, which allows for the state of the grid to be updated without interrupting services.
- Automating interactions with FSPs, so that bids and dispatch instructions are seamlessly shared between the FSP and the DSO.

In addition to benefits for transaction costs, Strata has other benefits for the use of digitalisation, such as enhanced cybersecurity features (e.g., secure one-way traffic via VPN connections).

6.2.7. Other barriers

A significant barrier with all digitalisation sub-solutions is cybersecurity concerns. With further digitalisation of the electricity system, the number of points of attack, and possibly the number of vulnerabilities, grows. Concern for cybersecurity has grown among policymakers, so the topic is being addressed with multiple initiatives and rules in the EU, including the Network Code on Cybersecurity.[180]

The value of both DERMS and H/BEMS also depends on the availability of ADMS in the wider grid. Without ADMS communicating and controlling DERMS and H/BEMS assets, little value can be extracted from the connected assets for flexibility services, grid operation and optimisation, or other uses. This problem is less relevant at HV grids, where automation and grid monitoring is already commonplace. However, for LV grids in DSOs, which are highly involved for both DERMS and H/BEMS transactions, there is often very little visibility on the system status.[181]

Likewise, standardisation remains an ongoing discussion for digitalisation solutions. New rules as developed in the upcoming Network Code on Demand Response will be significantly impactful in determining standards and protocols for communication and control of devices, which will be directly relevant for both DERMS and H/BEMS.

For DERMS, CAPEX bias is universally mentioned as the most significant barrier to the uptake of this digital technology. DERMS systems are both CAPEX-heavy and OPEX-heavy, and the heavier OPEX (compared to traditional grid infrastructure expansions) causes this technology to be disfavoured. In addition, the heavy cost of DERMS is usually not justifiable purely on financial grounds: they are simply too expensive. However, they still find many uses cases for their role in the grid integration of (decentralised) renewable energy sources.[182]

For H/BEMS, household and building owners may have difficulty in finding a suitable business case for these devices. While their costs can be readily established via vendors and markets, the benefits of these devices and their potential revenue sources can be far less clear. Especially in areas with less-established markets for relevant services (i.e. grid management and flexibility services), reaching a conclusion about the quantity of benefits and revenues can be very difficult.

[180] More details at https://www.entsoe.eu/network_codes/nccs/
[181] European Smart Grids Task Force Expert Group 3 (2019), Final Report: Demand Side Flexibility; Perceived barriers and proposed recommendations.
[182] Guidehouse Insights (2024), Guidehouse Insights Leaderboard: DERMS Providers.

Lastly, digitalisation efforts at organisations must be part of broad strategic plan. Digital ambitions require a larger cultural shift and a change in how business operations are carried out on a day-to-day and long-term basis. Thus, changing a specific system, e.g., by introducing functionality in DERMS to a DSO, requires a larger change throughout the organisation in how various other operations are carried out. Internal rigidity about processes and culture can thus reduce the real value of digitalisation for the organisation.[183]

Table 13 Barriers for digitalisation solutions

Barrier type	
Financial	• DERMS are too expensive to justify on grounds of costs. Rather, they are considered for boosting the grid integration of renewables. [184]
Social	• For HEMS/BEMS: consumers may be unable to consider the feasibility of these devices. These relate to not knowing of potential revenue sources (e.g., from DSF), the risks and opportunities of these devices, and the complexity of offers.
Technical	• Cybersecurity: increased digitalisation can increase vulnerabilities and points of attack. • The use of DERMS and BEMS/HEMS depend crucially on the existence of ADMS in the grid. The lack of ADMS is more acute at lower voltage grids. • While standardisation already exists for multiple interfaces (e.g., between BEMS and flex devices, between BEMS and FSP/network operators), the use of these standards is still in progress.
Regulatory	• DERMS are OPEX-heavy, so they are heavily disfavoured due to CAPEX bias caused by regulations of network operator cost recovery
Organisational	• Digitalisation efforts at organisations tend to involve a larger cultural shift and a change of operational practices. This requires consideration in strategic planning, and digitalisation ambitions can be tempered by internal resistance.

6.3. Local flexibility and EU balancing platforms

6.3.1. Description of the solution

European balancing platforms have been developed in order to enable the sharing of balancing energy and capacity as well as imbalance netting across Europe. The Electricity Balancing Regulation (EB Regulation)[185] introduced in 2017, mandates the establishment of market platforms to facilitate cross-border trading of **balancing energy**. As part of this obligation, four platforms have been developed:

- **IGCC (IN)**: The International Grid Control Cooperation (IGCC) [186] is the European platform for imbalance netting, which is the process agreed between TSOs of two or more Load Frequency Control (LFC) areas that allows avoiding the simultaneous activation of frequency restoration reserves (FRR) in opposite directions by considering the respective frequency restoration control errors. Imbalance netting contributes to reduced needs of power balancing from TSOs and therefore minimizing the amount of automatic FRR needed. IGCC was introduced in 2010 with 24 countries and 27 TSOs participating to date.
- **PICASSO (aFRR)**: The aFRR Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO)[187] is the European platform for the exchange of balancing energy from aFRR, It also includes implicit imbalance netting of aFRR for participating countries, reducing the

[183] DNV (2024), Energy Industry Insights 2024 Main Report.
[184] McKinsey et al. (2022) Digitalisation of Energy Flexibility
[185] Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing
[186] https://www.entsoe.eu/network_codes/eb/imbalance-netting/
[187] https://www.entsoe.eu/network_codes/eb/picasso/

imbalance netting through the IGCC. [188] The platform went live in June 2022 with 4 countries (AT, CZ, DE, IT) and 7 TSOs participating.[189]

- **MARI (mFRR)**: The Manually Activated Reserves Initiative (MARI) is the European platform for the exchange of balancing energy from mFRR. The platform started operation on October 2022 with Austria, Czechia and Germany participating. Additional TSOs are not expected to participate until the first quarter of 2024.[190]
- **TERRE (RR)**: The Trans European Replacement Reserves Exchange (TERRE) is the European platform for the exchange of balancing energy from Replacement Reserves (RR). TERRE was launched in January 2020, with the TSOs from Czechia, France, Italy, Portugal, Spain, and Switzerland participating in the platform as of January 2021. The Polish TSO is expected to join the platform in Q2 2024.[191]

On the other hand, cross-border trading of balancing capacity is voluntary at this stage, therefore balancing capacity markets remain mostly at a national level. The following platforms have been or are being developed on a voluntary basis for **sharing or exchanging balancing capacity**:

- **Nordic aFRR market**: the Nordic TSOs (from Norway, Sweden, Finland and Denmark) implemented the Nordic aFRR balancing services which has become operational in December 2022. [192] A common Nordic capacity market also for mFRR was expected to be launched in February 2024.[193] A public consultation is currently being organised (from 16 February to 18 March 2024.[194]
- **ALPACA**: ALPACA is a voluntary TSO cooperation between Austria, Germany and Czechia aiming at improving the balancing abilities of the TSOs by improving the access to aFRR and by reducing the aFRR procurement costs by creating a common aFRR balancing capacity market.
- **FCR Cooperation**: The FCR Cooperation is a voluntary cross border exchange platform comprising of 12 TSOs from nine countries (Austria, Belgium, Czechia, Denmark, France, Germany, the Netherlands, Slovenia, and Switzerland) with the aim to establish a common market for the procurement and exchange of FCR capacities. [195]

Furthermore, due to the rapid increase of DERs in the energy system, a need for local flexibility platforms has emerged at TSO and DSO level. Local flexibility platforms allow the participation of flexibility providers in various markets, particularly for the trade of balancing and/or congestion management products.

Frontier Economics (2021) states that local flexibility platforms allow to "facilitate or co-ordinate the trade, dispatch and/or settlement of energy or system services between T/DSOs and DER. This includes platforms that are self-contained marketplaces, as well as platforms that act as intermediaries to established wholesale and balancing markets".[196]

[188] ACER (2023) Progress of EU electricity wholesale market integration 2023 Market Monitoring Report
[189] ACER (2023) Progress of EU electricity wholesale market integration 2023 Market Monitoring Report
[190] ACER (2023) Progress of EU electricity wholesale market integration 2023 Market Monitoring Report
[191] ACER (2023) Progress of EU electricity wholesale market integration 2023 Market Monitoring Report
[192] ACER (2023) Progress of EU electricity wholesale market integration 2023 Market Monitoring Report
[193] https://nordicbalancingmodel.net/the-planned-go-live-date-for-a-norwegian-mfrr-capacity-market-is-set-for-sunday-11-february/
[194] Public Consultation: Trilateral mFRR capacity market between Denmark, Finland and Sweden – nordicbalancingmodel
[195] ACER (2023) Progress of EU electricity wholesale market integration 2023 Market Monitoring Report
[196] ENTSO-E and Frontier Economics (2021) Review of flexibility platforms

Due to increasing congestion on the distribution grid, DSOs are also becoming interested to procure flexibility to prevent/reduce congestion. Via the platforms, both TSOs and DSOs can actively procure ancillary and congestion management services, as seen for example in GOPACS[197] and INTERRFACE[198] platforms. But the platforms can also facilitate trading between market parties. Flexibility markets, such as Piclo Flex[199] and NODES[200], are a subset of local flexibility platforms where the markets are cleared and transactions settled within the platform (while other platforms may act only as intermediaries, allowing small and new actors for example to participate in established markets). Local flexibility platforms are often more focused on localised procurement of congestion management services by DSOs.

6.3.2. Challenges addressed by the solution

Solution	Examples of sub-solutions	Higher complexity to identify system needs	Limited grid connection capacity	Limited cross-zonal capacity & low utilisation	Increasing congestion in networks	Increasing balancing needs	Non-frequency ancillary service needs
Flexibility and EU balancing platforms	Flexibility platforms / markets		**T/D**	**T**	**T/D**	**T**	**T/D**
	EU balancing platforms			**T**		**T**	

T/D: Transmission/distribution
High / medium / untested potential to address challenge

The development and implementation of EU balancing and flexibility platforms address several challenges identified in this study.

- **Reduced need for investments in grid expansion and reinforcement**: EU balancing platforms facilitate cross-border exchange of energy, allowing for better managing imbalances in real time. As a result, they contribute to the efficient utilization of existing cross-border infrastructure although there are specific challenges in calculating and allocating capacity across multiple timeframes. Furthermore, by enabling imbalance netting and efficient utilization of balancing energy considering available transmission capacities, EU balancing platforms can hence help defer investments in grid expansion and upgrade.
- **Unlocking distribution network capacity and improving congestion management**: Local flexibility platforms are facilitating congestion management, freeing up distribution level capacity that can be then used to connect new assets and therefore deferring DSO investments. Balancing platforms minimize geographical constrains by allowing cross border exchange of flexibility between TSOs in different zones. This reduces reliance on local balancing resources, potentially lowering costs and mitigating curtailment issues.
- **Better functioning of balancing markets:** besides providing access to geographically dispersed flexibility, EU balancing platforms improve price signals leading to fair competition and potentially lower prices for balancing services. Local flexibility platforms can in addition facilitate the participation of smaller and decentralised flexibility assets in the EU balancing markets.

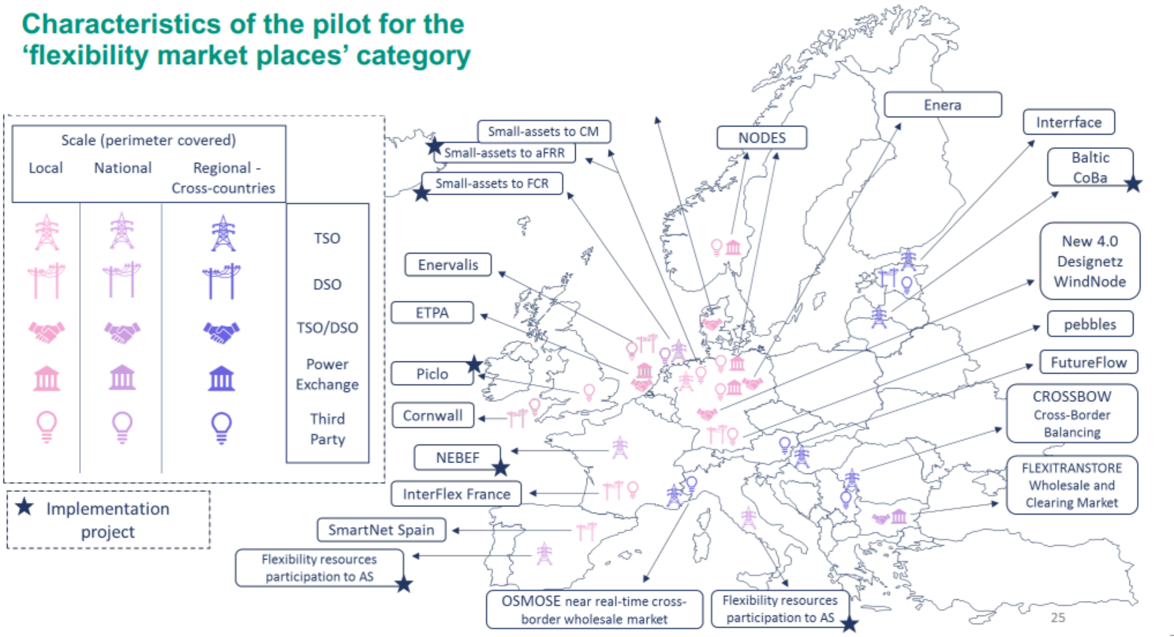
[197] https://www.gopacs.eu/
[198] http://www.interrface.eu/content/single-flexibility-platform
[199] https://picloflex.com/
[200] https://nodesmarket.com/

- **Use of platforms for non-frequency ancillary services**: flexibility platforms can assist in the provision of non-frequency ancillary services, such as voltage control.[201]

6.3.3. Examples of application

There are several emerging platforms across Europe at local, national and regional level and in different stages of development. Figure 19 provides an overview of the main existing platforms, as recorded by ENTSOE in 2019[202], yet several others have appeared in the latest years – however, a more recent map of local flexibility platforms in the EU is not available.

Figure 19 Local flexibility platforms across Europe



Source: ENTSOE (2019)

GOPACS

The Grid Operators Platform for Congestion Solutions (GOPACS) is owned by the Dutch TSO TenneT and four DSOs and acts as a market intermediary platform. The purpose of the platform is to support the coordinated market-based procurement of congestion management services by participating energy market operators in the Netherlands (intra-day markets).[203] Up to January 2024, 530 GWh of flexibility has been procured through the platform by TenneT (TSO) and almost 200 MWh by Liander (one of 3 main Dutch DSOs).[204]

NODES

NODES is an independent market operator launched in 2018 with several projects in Norway, Germany, and the UK. It provides a marketplace to trade local flexibility, enables DSOs to manage congestion and allows the coupling of the TSOs' balancing markets to the local flexibility markets.[205] For reference, the English DSO Western Power Distribution (WPD) procured from the Intra-flex project 116 MWh of flexibility in August 2021[206]. According to the available data for 2023, the Norwegian electricity provider Agder Energi Nett procured 278 MWh of flexibility from the NorFlex project in the first 12 weeks of 2023.

[201] The FlexGrid project can serve as an example project.
[202] ENTSO-E (2019) Flexibility framework and mapping- webinar
[203] ENTSO-E and Frontier Economics (2021) Review of flexibility platforms
[204] Data from GOPACS expenses report
[205] https://nodesmarket.com/flexibility/
[206] https://nodesmarket.com/intraflex/

Pilot project for flexibility services in Portugal

The following regulatory framework and project description is elaborated based on the kind inputs from the Portuguese NRA ERSE.

Regulatory framework

Article 123 of Decree-Law no. 15/2022 foresees the use of flexibility services by system operators as an alternative to new investments in infrastructure, echoing Article 34 of Directive 2019/944. The use of flexibility services is recognized as increasingly crucial for the transition to an electric system with high levels of renewable generation integration.

One key element of the Networks Operation Code (ROR) is the Manual on Procedures for the Technical Management of electricity distribution networks. Article 68 of ROR provides that this Manual will, among other aspects, establish the applicable rules to acquisition, utilization, compliance and settlement of flexibility services. According to ROR, DSOs shall submit a draft proposal of this Manual which ERSE will subsequently approve within the framework of a public consultation. At the moment, ERSE expects a proposal to be submitted by the DSO E-REDES , drawing from the pilot project experience.

FIRMe

FIRMe is a pilot project developed and executed by E-REDES (Portugal's largest electricity DSO) providing a number of flexibility services launched at the end of 2022 by E-REDES, Portugal's biggest electricity DSO[207]. This pilot project was approved by ERSE at the end of 2023, under Article 78 of ROR. The stated objectives of this project are: "to adapt to the flexibility requirements and test the market by raising awareness among the players (flexibility service providers - FSPs) and encouraging them to participate in this new local flexibility market".

Through this project, E-REDES proposed to procure flexibility services from distribution network users. Management of the tendering process and typification of flexibility products was contracted with the Piclo platform[208]. Tender Rules [209] and Standard Contracts [210] for Flexibility Service Providers were developed by the project managers and made publicly available by E-REDES.

The project is now in its initial phase of operations, during which three types of flexibility products were procured:

- **Dynamic**: flexibility service for use during periods of network maintenance, as an alternative to the utilisation of a mobile substation; availability request 1 week ahead and activation with a 15-minute warning; estimated frequency of 1 maintenance event per 2 years;
- **Secure**: flexibility service for the management of consumption peaks; periods of availability of the flexible assets defined in advance; frequent utilisation during the defined periods of availability;
- **Restore**: flexibility service for the restoration of energy supply during sporadic events of interruption of supply and network failure; availability of the asset paid

[207] https://www.e-redes.pt/en/energy-transition/power-grids-future/firme#faq_31506
[208] https://piclo.webflow.io/profiles/e-redes
[209] https://www.e-redes.pt/sites/eredes/files/2023-08/Regulamento_concursos_prestacao_servicos.pdf
[210] https://www.e-redes.pt/sites/eredes/files/2023-08/Contrato_de_servicos_de_flexibilidade.pdf

annually with activation during the interruption event; interruption probability of between 1% and 5% annually.

Assessment of local flexibility offers

Identifying and selecting offers for flexibility services involves an analysis of the flexibility services versus counterfactual solutions appropriate to the service being offered.

In this way, the use of local flexibility services implies significant changes in planning processes, namely: 1) identification and cost-benefit analysis of solutions based on flexibility services and 2) determination of the maximum price for flexibility services that guarantees indifference compared to the conventional solution (called the reserve price).

The characteristics and reserve price of flexibility services are based on the technical-economic analysis of each specific situation and the assessment of technical requirements for implementing the flexibility alternative which are: 1) expected response parameters (power, voltage, response time), 2) forecast of service use (periods, duration), 3) geographic requirements (region of the network where the constraints are located).

The "flexibility value" is given by the investment deferral benefit plus possible unique benefits of the flexibility solution minus the benefits not captured by the flexibility solution, such as the ones resulting from a reduction in technical losses.

The Dynamic flexibility service, which consists of using flexibility in periods of maintenance, brings benefits of reducing financial costs for the electrical system and reduction of environmental costs by reducing emissions associated with not using counter-factual alternative: the mobilization of a mobile substation.

The Secure flexibility service, used to manage peak consumption in certain network points, brings benefits of investment deferral and faster connection of customers. The counter-factual alternative is investment in network reinforcement.

The Restore flexibility service, used to support restoration in the presence of network failures, essentially brings social benefits to the electrical system associated with the reduction of energy not supplied in case of failure. A counter-factual alternative is the interruption of additional customers and consequent increase in energy not supplied (which, for the purposes of investment projects, is valued at €4.5/kWh).

6.3.4. Costs of the solution

According to the ENTSOE Balancing cost report (2023)[211], the cumulative CAPEX for the period 2018-2022 of the balancing energy platforms (TERRE, MARI, PICASSO, IGCC) amounted to €35.3 million, including costs of establishment and amendments, such as IT development, data management, testing etc. (Table 14). The forecasted CAPEX for 2023 is expected to reach €8.8 million, which will then increase the cumulative CAPEX of the platforms to €44 million. The total operating costs (OPEX) for all platforms in 2022 amounted to €2.2 million and are expected to increase to €3.6 million in 2023, with TERRE and MARI recording the highest maintenance costs.

According to the review conducted for TSO/DSO cooperation solution under section 6.4, ICT costs for a platform for a TSO procuring flexibility from decentralised flexibility providers

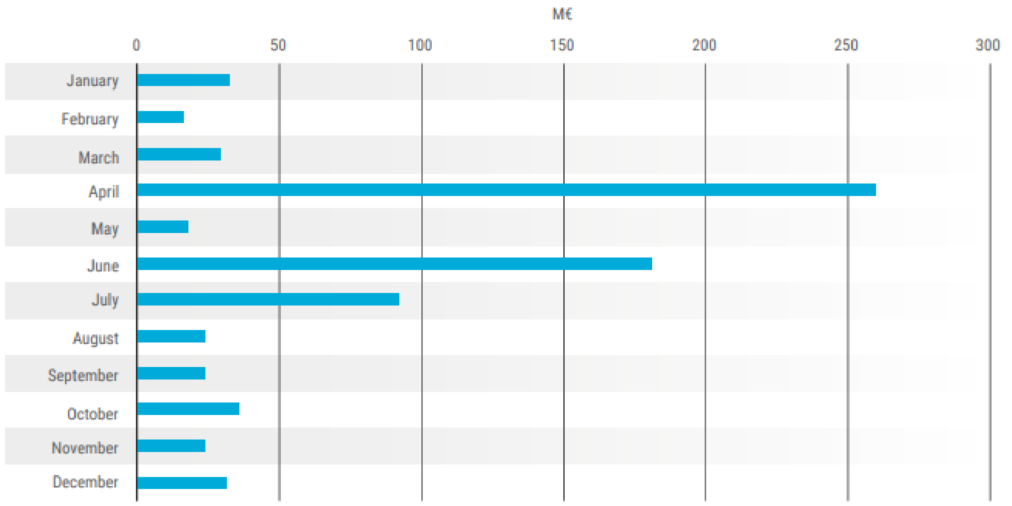
[211] ENTSOE (2023) Electricity Balancing Cost Report 2023

could amount to almost 50 M€, while ICT solutions for procuring also flexibility services for DSOs (in addition to the TSO needs) could amount to around 100 M€.

6.3.5. Benefits of the solution

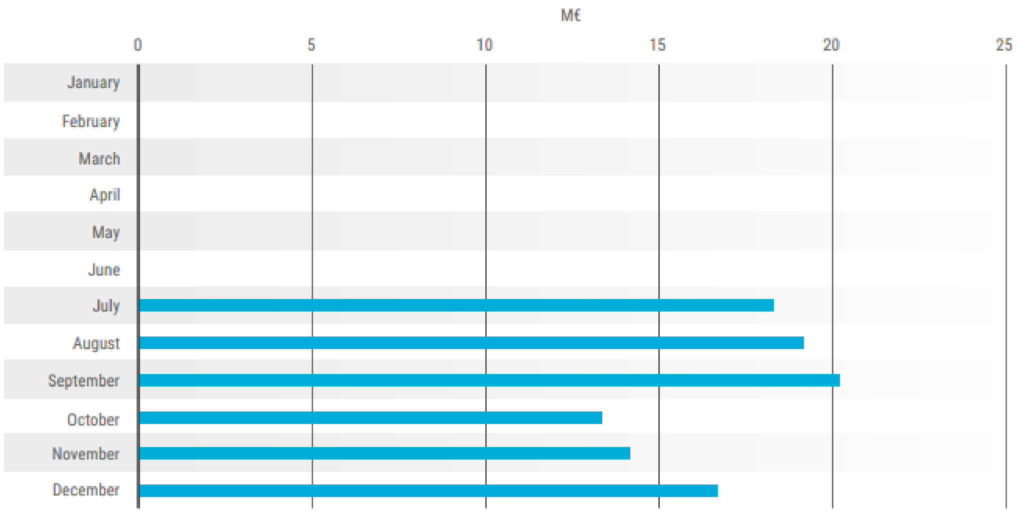
The ENTSO-E Market report of 2023[212] provides some key indicators to estimate the social welfare benefits of the balancing platforms, nonetheless they do not capture the entirety of the benefits. For TERRE and PICASSO platforms the differential Final vs DC indicator is used. For the TERRE platform, the monthly benefits in 2022 ranged on average between €30 to €40 million but peaked in April at around €260 million (Figure 20). The results for PICASSO do not cover a full year due to the go-live date, with benefits being observed from July on, and ranging from €13 to €20 million (Figure 21).

Figure 20 TERRE (RR) differential Final vs DC (Social Welfare Final – Social Welfare decoupled run) in 2022 (M EUR)



Source: ENTSOE (2023) Market report

Figure 21 PICASSO (aFRR) : differential Final vs DC (Social Welfare Final – Social Welfare decoupled run) in 2022 (M EUR)

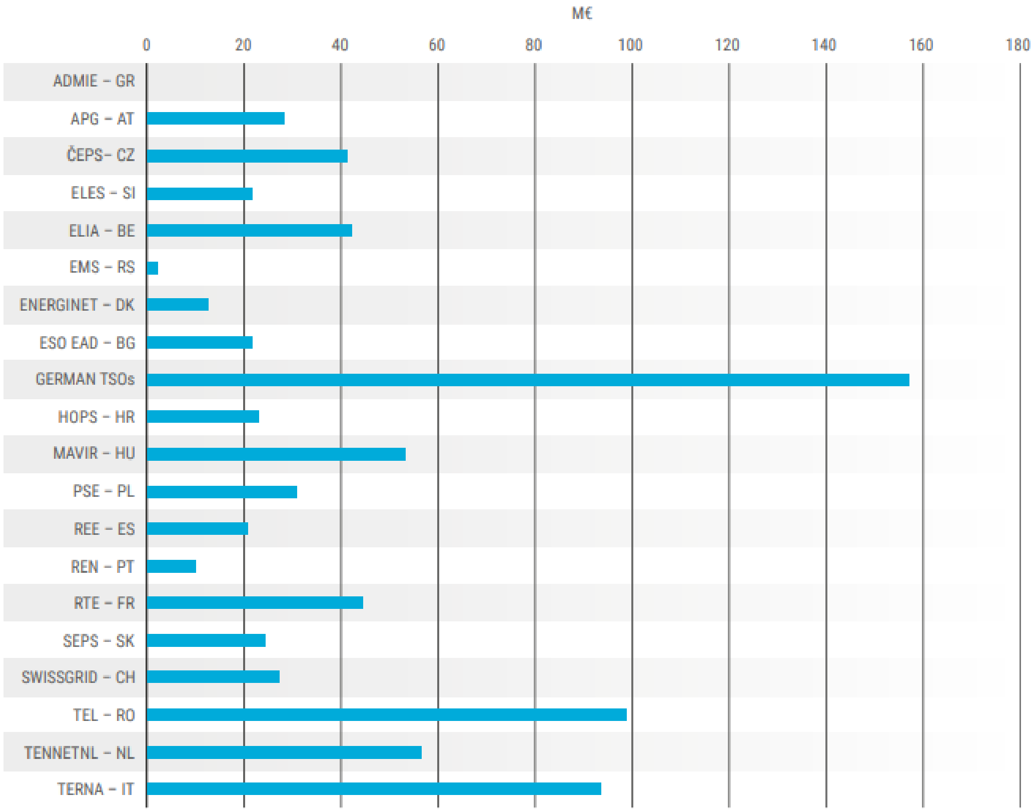


Source: ENTSOE (2023) Market report

[212] ENTSOE (2023) market report

The **benefits of the IGCC (IN) platform** are in the report presented per TSO: the German TSOs recorded the highest benefits with almost €160 million savings in 2022, followed by the Romanian TSO with about €100 million and the Italian TSO with around €95 million (Figure 22).

Figure 22 IGCC (IN): monetary annual savings per TSO in 2022 (M EUR)



Source: ENTSOE (2023) Market report

Finally, the **societal benefits of FCR cooperation** (balancing capacity platform) are by ENTSOE estimated at €67 million in 2022, slightly higher than in 2021 (€60 million).

Table 14 Costs and benefits of EU platforms for 2022

Solution	Region / case	CAPEX[213] [M€]	OPEX[214] [M€]	Benefits
TERRE (RR)	CH, CZ, ES, FR, IT, PL, PT	11.35	1.58	Social welfare: 810 M€
MARI (mFRR)	EU-27[215], CH, NO	17.91	0.12	n.a
PICASSO (aFRR)	EU-27[216], CH, NO	5.85	0.49	Social welfare: 200 M€[217]
IGCC (IN)	EU-27[218], CH	0.2	0.04	Annual savings: >750 M€
FCR cooperation	AT, BE, CH, DE, DK, FR, NL, SI	n.a	n.a	Social welfare: 67 M€

[213] CAPEX accounts for all costs incurred in the period 2018-2022
[214] Values for 2022
[215] Excluding Malta and Cyprus. Ireland participates as observer
[216] Excluding Malta, Cyprus, Ireland. Estonia, Lithuania, Latvia are participating as observers.
[217] Extrapolated to a full year, as available data only covers Jul-Dec.
[218] Excluding Finland, Ireland, Malta, Cyprus, Latvia, Estonia and Sweden

6.3.6. Transaction costs

Local flexibility and balancing platforms involve a range of transactions and related costs that impact various actors within the electricity system, namely:

- Platform entry;
- Participation;
- Data management and forecasting;
- Market clearing; and
- Accounting and billing.

Transaction costs emerge in the **platform entry** between the platform operator and the concerned participants (network operators, FSPs, etc.). The platform operator defines the criteria and requirements for participation, as well as any entry fees. There is a low level of information asymmetry between parties, in terms of entry costs and benefits, given that balancing platforms are usually rather clear about requirements and platform functionality. Nonetheless, the outcomes of a specific party joining the platform may not always be clear, both for the platform and for the party.[219] The transaction costs of this category are medium for S&I costs, and medium for B&D costs (setting up the contract and timeline) and constitute a moderate share of the total transaction costs.[220]

Participation in the platforms also involves some transaction costs among the platform operators and the market participants (network operators, FSPs, aggregators, etc.). Considering the complex transactions and the auctions occurring daily, market participants must maintain a dedicated team capable of swiftly gathering required information, making decisions, and acting in the market. However, actions in the market are usually standardised to some extent. Thus, there is a medium level of S&I costs while the B&D and P&E costs are low.

Furthermore, **data management and forecasting** are transactions between the network operators and the platform operators. Platform operators collect data for the flexibility needs, usually from TSOs/DSOs, and request offers from BRPs and FSPs to provide these services. Ensuring that correct protocols and standards are used for data storage and communication are highly relevant in this regard and lead to medium B&D costs (while S&I and P&E costs are low).

Market clearing is a transaction that occurs between the platform operator and the concerned parties (e.g., network operators, FSPs, aggregators, etc.). It involves the collection of bids, calculation of the clearing prices based on financial and technical criteria, and communication to the market participants. It involves a low level of transaction costs, as these transactions have low information asymmetry and involve mostly automated activities.

The **accounting and billing** process encompasses transactions related to settlements, reconciliation, billing, and processing payments. These transactions mostly generate P&E costs which are expected to be medium (as most processes are automated) and involve interactions between the platform operators, network operators, BRPs, and FSPs.

[219] See for example recent controversy about TERNA's participation in the PICASSO platform.
[220] UMEI (2021) Identification of relevant market mechanisms for the procurement of flexibility needs and grid services

Interactions for settlement purposes are often short-term and frequent, especially in cases that require system balancing and network congestion.

GOPACS

The Grid Operators Platform for Congestion Solutions (GOPACS) is set up by the Dutch TSO TenneT and four DSOs and acts as a market intermediary platform. Its purpose is to support the coordinated market-based procurement of congestion management services by participating energy market operators in the Netherlands (intra-day markets).[221] GOPACS does not have strict pre-qualification requirements and validation processes, while there are no extra costs that market participants should pay besides the costs of participating in the ETPA market platform. Up to January 2024, 530 GWh of flexibility has been procured through the platform by TenneT (TSO) and almost 200 MWh by Liander (a major Dutch DSO).[222]

NODES

NODES is an independent market operator launched in 2018 with several projects in Norway, Germany, and the UK. It provides a marketplace to trade local flexibility, enables DSOs to manage congestion and allows the coupling of the TSOs balancing markets to the local flexibility markets.[223] NODES has relatively flexible regulatory, commercial and capacity requirements for the FSPs.[224]

For reference, the English DSO Western Power Distribution (WPD) procured from the Intra-flex project 116 MWh of flexibility in August 2021[225]. According to the available data for 2023, the Norwegian electricity provider Agder Energi Nett procured 278 MWh of flexibility from the NorFlex project in the first 12 weeks of 2023.

These platforms were designed to greatly improve available services for network operators, and to facilitate these transactions by standardising their trade. In addition to boosting liquidity in these markets, standardised transactions and accessible market information reduces information asymmetries between participants, standardises transactions, and thus reduces transaction costs.

6.3.7. Other barriers

Local flexibility platforms encounter regulatory barriers that impede their development and effectiveness in energy markets. High entry and compliance costs and non-harmonised entry and participation requirements across platforms may pose challenges for FSPs, in particular smaller market parties and aggregators, deterring new entrants and hindering market participation. These requirements include high minimum bid size requirements, high maximum allowed time for reaction of the flexibility source, high

[221] ENTSO-E and Frontier Economics (2021) Review of flexibility platforms
[222] Data from GOPACS expenses report
[223] https://nodesmarket.com/flexibility/
[224] European Commission, Joint Research Centre, Chondrogiannis, S., Vasiljevska, J., Marinopoulos, A. et al., Local electricity flexibility markets in Europe, Publications Office of the European Union, 2022, https://data.europa.eu/doi/10.2760/9977
[225] https://nodesmarket.com/intraflex/

duration of delivery, etc.[226] In practice, impact on EU balancing platforms has been rather limited, as most markets still have sufficient liquidity to satisfy (almost all) demand.[227]

Another issue often referred to in the literature is the lack of standardisation across platforms for protocols for data sharing, definition of asset and product characteristics as well as formatting and content of bids and offers.[228] The complex coordination of the involved stakeholders such as TSOs, DSOs, BRPs, FSPs, platform operators, etc, may pose a challenge to the smooth operation of local flexibility platforms, and may require organisational changes in some stakeholders.[229] Finally, cybersecurity threats and data privacy concerns pose significant risks to local flexibility platforms, necessitating robust security measures and regulatory compliance to safeguard sensitive information and maintain trust among stakeholders.

Table 15 Barriers for local flexibility and EU balancing platforms[230, 231,232, 233, 234]

Barrier type	
Regulatory	• Regulatory uncertainty due to evolving regulatory landscape • High entry costs and different entry requirements per platform • Lack of universal definitions and product characteristics • Minimum bid requirements • Maximum reaction time of the flexibility source and duration of delivery
Technical	• Lack of standardisation of data sharing • Lack of Standardisation of format and content of bids • Cybersecurity and data privacy
Organisational	• Complex coordination is needed between stakeholders (network operators, FSP, BRPs etc.)

6.4. TSO/DSO cooperation solutions

6.4.1. Description of the solution

TSO/DSO cooperation is challenging to define, as TSOs and DSOs have always needed to cooperate to a certain extent. In this context, the term refers to **cooperation between the two network operator types in a stronger degree or on a number of new areas**. This increased or new cooperation is **required due to the accelerated deployment of decentralised energy resources at the distribution level**. The development of DERs increases the need for active system management by DSOs, provides additional flexibility resources which can be used to manage the new challenges not only at distribution but also at transmission level, as well as introduces new actors in the energy sector requiring access to the electricity markets. In addition, TSO-TSO cooperation is also possible, and is currently significantly more regulated in the EU (for example through increasing coupling across the different market timeframes) compared to TSO/DSO cooperation.

[226] Palm et al. (2023) Drivers and barriers to participation in Sweden's local flexibility markets for electricity. https://doi.org/10.1016/j.jup.2023.101580
[227] See KPIs reported in November 2023 presentations at https://www.entsoe.eu/events/2023/11/30/balancing-platforms-stakeholders-workshop/
[228] Ibid.
[229] UMEI (2021) Identification of relevant market mechanisms for the procurement of flexibility needs and grid services
[230] ENTSO-E and Frontier Economics (2021) Review of flexibility platforms
[231] Ofgem (2019) Ofgem's Future Insights Series Flexibility Platforms in electricity markets
[232] https://electron.net/market-platforms-lowering-barriers-to-entry-flexibility-service-providers/
[233] UMEI (2021) Identification of relevant market mechanisms for the procurement of flexibility needs and grid services
[234] Palm et al. (2023) Drivers and barriers to participation in Sweden's local flexibility markets for electricity. https://doi.org/10.1016/j.jup.2023.101580

The concept of TSO/DSO cooperation is not only relevant in unbundled markets where the TSO and DSO are not the same entity,[235] but increased coordination between transmission and distribution activities is also necessary for combined network operators or vertically integrated utilities.

TSO/DSO cooperation can involve cooperation in, among others, the areas presented in the figure below. In essence, **coordination can occur on three main categories of activities:**

- **Data exchange,** meaning activities where there is no further active collaboration beyond data exchange – network operators exchange the information, but they take the relevant operational decisions independently. This might include, for example, the provision of information about the distribution-related constraints by the DSO to the TSO, in order to facilitate the participation of DERs in wholesale or TSO-managed ancillary service markets;
- **Joint system operation,** where network operators actively cooperate to manage the system and address constraints at the transmission and distribution levels. This comprises first identifying the relevant system constraints, and then managing those – whether related to congestion management, balancing, voltage control, black start capability or other system management activities. Joint system operation might also include cooperation in coordinating actions to ensure actions from one network operator do not have a detrimental effect on the other operators' system (e.g. ensuring procurement of congestion management services from DERs does not worsen system imbalances);
- **Connection-related activities**, as the name states, comprises active coordination for the connection of network users – both in setting grid connection requirements for generators, storage operators and off-takers, as well as to define the most appropriate connection level from a system perspective.

[235] Neuhoff et al. (2018) TSO-DSO-PX Cooperation II. Report on key elements of debate from a workshop of the Future Power Market Platform

Figure 23 Areas for TSO/DSO cooperation, adapted from IRENA (2020)[236]

Data exchange

- On DER/flexibility assets
- On system planning and models
- On network capacity

Joint system operation

- Assessment of system constraints
- Congestion management
- System protection and restoration

Connection-related

- Definition of grid connection requirements
- Definition of connection level (transmission/distribution)

TSOs and DSOs are already required to cooperate as stated in EU legislation. In particular, article 57 of the Electricity Directive requires that **DSOs and TSOs "cooperate with each other in planning and operating their networks**", explicitly detailing requirements on data exchange as well as on achieving coordinated access to DER resources which could help address the network operators' needs. Other provisions exist for example in the network codes and guidelines, such as article 15 of the Electricity Balancing Guideline on cooperation with DSOs. The upcoming network code on demand response will also contain provisions regarding system operators' coordination, including TSO/DSO cooperation.[237]

It must also be noted that while much attention is given to TSO/DSO cooperation, in practice cooperation is needed between many electricity sector actors, notably also with nominated electricity market operators. However, TSO/DSO cooperation is often highlighted because of the large number of areas where coordination is increasingly required.

[236] IRENA (2020) Co-operation Between Transmission and Distribution System Operators - Innovation Landscape Brief
[237] EU DSO Entity and ENTSO-E (2023) Article 69 of the Draft Proposal for a Network Code on Demand Response

6.4.2. Challenges addressed by the solution

Solution	Examples of sub-solutions	Higher complexity to identify system needs	Limited grid connection capacity	Limited cross-zonal capacity & low utilisation	Increasing congestion in networks	Increasing balancing needs	Non-frequency ancillary service needs
TSO/DSO cooperation	Data exchange	T	T/D		T	T	T
	Joint system coordination			T	T/D	T	T/D
	Connection-related activities	T/D	T/D				

T/D: Transmission/distribution
High / medium / untested potential to address challenge

TSO/DSO cooperation helps in essence address almost all identified challenges faced by network operators, as these challenges are in fact the main drivers for coordination:

- **Higher complexity to identify the system needs:** with the increasing penetration of DERs, data exchange and further TSO/DSO cooperation is essential to activities related to the identification of system needs. Without such cooperation, each individual network operator cannot adequately identify the needs and therefore not adequately plan its network development and operations;
- **Large investment needs:** TSO/DSO cooperation can enable the deferral of network investments in both transmission and distribution networks[238] and thus reduce investment needs compared to a counterfactual without coordination. This can happen through a number of ways, including by facilitating the access of DERs to wholesale and ancillary service markets, providing better visibility on system constraints and possible contingencies.
- **Limited grid connection capacity:** Coordination between TSOs and DSOs can allow for a more accurate identification of remaining grid capacity as well as ensure new network users are connected at the most appropriate level;
- **Increasing need for ancillary services and congestion management:** Coordination allows for better identification of the system-wide and local flexibility services' needs, as well as enables the participation of DERs in the procurement mechanisms of not only DSOs, but also TSOs.

6.4.3. Example(s) of applications

Various examples of enhanced TSO/DSO cooperation are in operation in the EU and elsewhere. ENTSO-E and the EU DSO Entity created with the Clean Energy Package are mandated to cooperate on a number of areas, and have signed a memorandum of understanding in 2022.[239] Other cooperation between the two entities comprise on the TYNDP scenarios, on the different network codes, on a joint working group on reference role models for data interoperability, and a joint task force on digital grid and smart grid indicators.[240]

An increasing number of cooperation activities concern joint platforms for the procurement of ancillary services and congestion management for the TSOs and DSOs, and

[238] IRENA (2020) Co-operation Between Transmission and Distribution System Operators - Innovation Landscape Brief
[239] ENTSO-E – TSO/DSO cooperation
[240] EU DSO Entity (2023) On the move: DSO Entity's strategic priorities for 2023

therefore fall under the examples of local flexibility platforms detailed in section 6.2. Examples include GOPACS (NL) and Flexhub (BE).[241] An example of connection-related cooperation is the coordination initiative for non-firm connection agreements between the DSO E-Redes and the TSO REN in Portugal.[242]

In addition to operational schemes, there are many projects dedicated to the research and development of TSO/DSO cooperation solutions. A number of projects are listed in:

- **INTERRFACE**, which aimed to "design, develop and exploit an Interoperable pan-European Grid Services Architecture (IEGSA) to act as the interface between the power system operators (TSO and DSO) and grid users and allow the seamless and coordinated operation of all stakeholders to use and procure common services";[243]
- **SmartNet**, which aimed to "provide optimised instruments and modalities to improve the coordination between the grid operators at national and local level … and the exchange of information for monitoring and for the acquisition of ancillary services … from subjects located in the distribution segment";[244]
- **CoordiNet**, which aimed to "1) demonstrate that coordination between TSO/DSO will lead to a cheaper, more reliable and more environmental friendly electricity supply to the consumers through the implementation of three demonstrations at large scale; 2) define and test a set of standardised products and the related key parameters for grid services; and 3) specify and develop a TSO-DSO-Consumers cooperation platform starting with the necessary building blocks for the demonstrations."[245]

6.4.4. Costs of the solution

As TSO/DSO cooperation can involve multiple activities, it is not straightforward to identify information on the associated costs. As mentioned, an increasingly common TSO/DSO cooperation activity is related to the **procurement of balancing and congestion management services**. Kuusela et al. (2019)[246] have estimated the ICT costs for developing various market structures for the procurement of such ancillary services from DERs. The authors explore the costs of 5 different cases in the context of the SmartNet project:

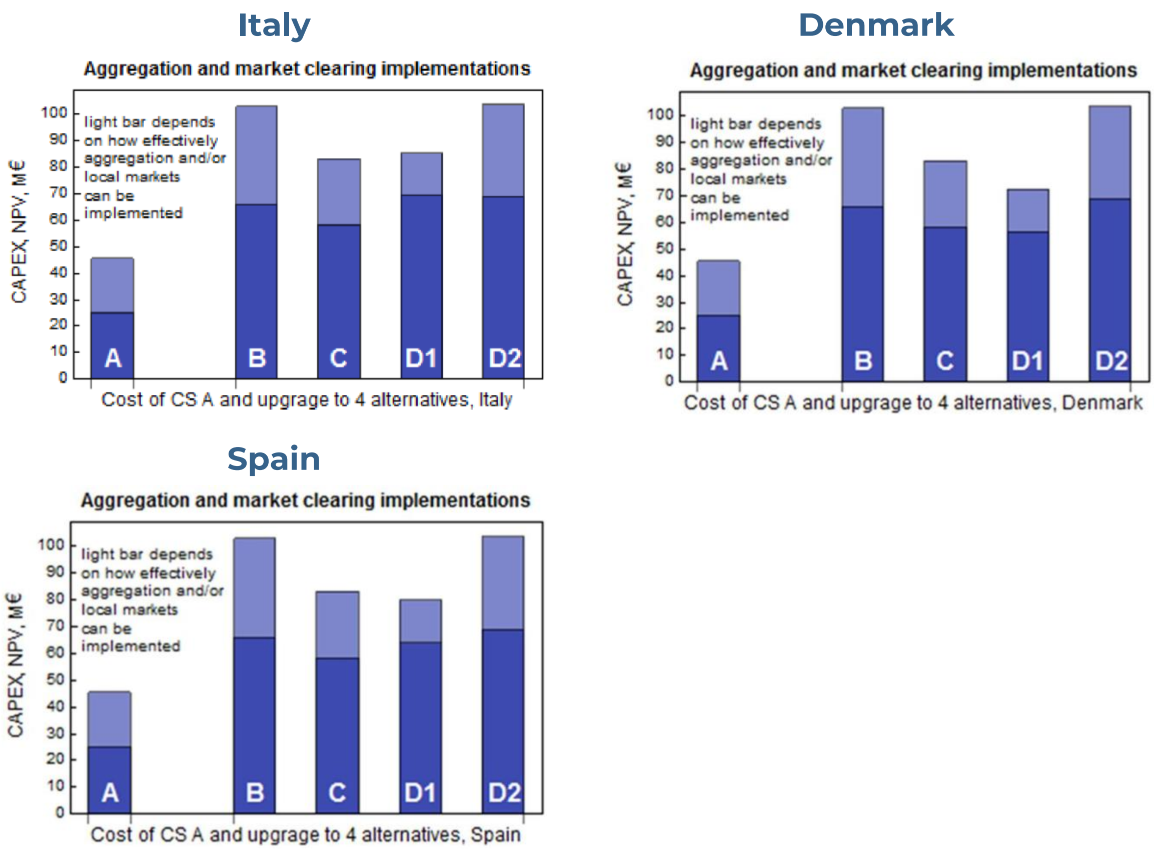
- **Coordination scheme A Centralized ancillary services market model**: Only the TSO procures balancing and CM services at transmission level, including from DERs;
- **Coordination scheme B Local ancillary services market model**: The DSO first procures congestion management services at distribution level, and the TSO can then procure its balancing and CM needs, including from DERs;
- **Coordination scheme C Shared balancing responsibility model**: The DSO and TSO manage their systems separately, both for balancing and congestion management;
- **Coordination scheme D Common TSO-DSO ancillary service market model**: The DSO and TSO simultaneously share DER resources, with the DSO being responsible for CM at distribution level and the TSO for balancing and CM at transmission level. This can be done in a centralised manner (D1) or decentralised (D2).

[241] c8_07_e_20200713_final_version_after_consultation.pdf (vreg.be) and FlexHub (synergrid.be)
[242] E.DSO (2023) Experiences for Optimising Renewables' Integration in the Distribution Grid
[243] INTERRFACE – Project description
[244] SmartNet – Project description
[245] Cordis – CoordiNet project summary
[246] KUUSELA (2019) An ICT Cost Comparison of Different Market Structures for Distributed Ancillary Services

The costs are estimated for Italy, Spain and Denmark, although country-specific costs vary only for scheme D. This scheme requires a significant data exchange and computational effort, and the related costs vary with the number of data to be exchanged and the amount of system nodes. The costs are further broken down between costs for the aggregator to participate in the TSO and DSO markets, costs for the TSO developing its market, and costs for developing local ancillary services markets. The OPEX are estimated to be approximately 20% of the investment costs, although this seems rather high.

The CAPEX estimations for the three countries are presented below, where it can be seen that the coordination scheme A (where only the TSO procures services) has the lowest ICT CAPEX, while the other schemes have higher costs, with the shared responsibility scheme C having the highest CAPEX in Italy and Spain due to the higher number of system nodes, and with the centralised common TSO-DSO ancillary service market scheme having the lowest CAPEX in Denmark due to the smaller system size.

Figure 24 Estimated ICT costs for various TSO/DSO cooperation schemes, Kuusela et al. (2019)[247]



6.4.5. Benefits of the solution

As part of the SmartNet project Rossi et al. (2020)[248] have conducted a **cost-benefit analysis of coordination schemes for procurement of balancing and congestion management,** for the same schemes for which ICT costs are detailed above. In addition to the ICT costs

[247] Kuusela (2019) An ICT Cost Comparison of Different Market Structures for Distributed Ancillary Services
[248] Rossi et al. (2020) TSO-DSO coordination to acquire services from distribution grids: Simulations, cost-benefit analysis and regulatory conclusions from the SmartNet project

estimated by Kuusela et al. (2019), the authors have also estimated the aFRR and mFRR costs to obtain a total system cost for 2030.

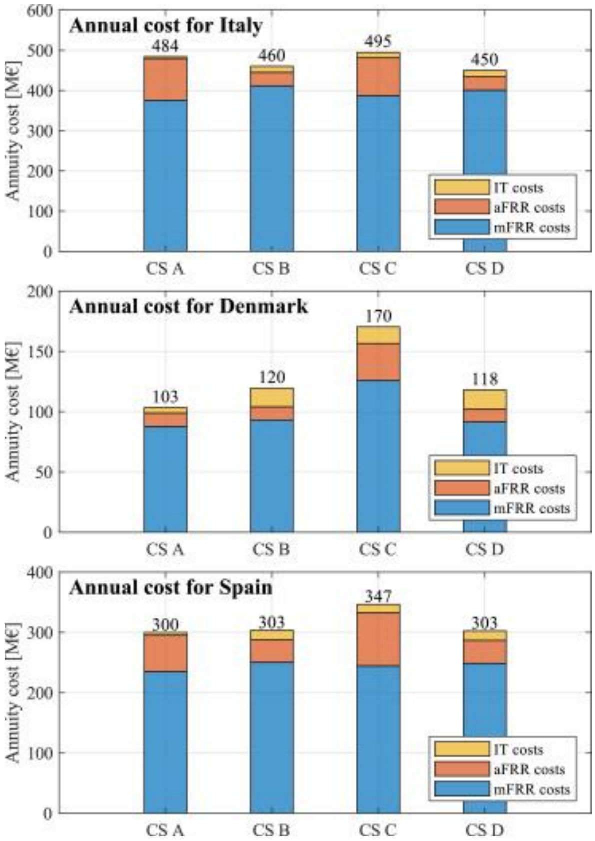
The results indicate that the coordination scheme with the lowest estimated costs vary per country, depending on the system size, available flexibility resources at the distribution level (EVs, PV generation or thermal loads) and also depending on the ICT costs. Thus, schemes were the DSOs are procuring congestion management (schemes B and D) have the lowest system costs in Italy and Spain, but in the case of Spain the ICT costs offset cost advantages compared to TSO-only procurement (scheme A). For Denmark, the TSO-only procurement scheme A has the lowest costs to procure aFRR and mFRR services, even not considering ICT costs.

Table 16 Costs and benefits of TSO/DSO cooperation for 2022

Solution	Region / case	CAPEX[249] [M€]	OPEX [M€]	Benefits	Benefit-to-CAPEX ratio
A: Centralized AS market model		25-45	5-9	N/A	N/A
B: Local AS market model		91-148	18-30	IT: 37 M€/y compared to A ES: 10 M€ compared to A	
C: Shared balancing market model		84-129	17-26	No benefits compared to A in any country	N/A
D2: Common decentralised TSO-DSO AS market model		94-149	19-30	IT: 47 M€/y compared to A ES: 10 M€ compared to A	

[249] CAPEX accounts for all costs incurred in the period 2018-2022

Figure 25 Annual total costs for balancing and congestion management in Italy, Denmark and Spain (2030 scenario)[250]



6.4.6. Transaction costs

The type, cost, and complexity of the transactions related to TSO/DSO cooperation depend on the sub-solution, with **joint system operation being particularly complex.** Joint system operation requires not only the set-up of the mechanisms (and underlying regulatory framework) for procuring system services, but also the realisation of transactions from capacity calculation to pre-qualification, tendering, verification of the suitability of the offerings, contracting and enforcement of the availability and delivery of procured services. Data exchange and particularly connection-related sub-solutions comprise a lower number of (less complex) transactions.

TSO/DSO cooperation mainly involves transactions between neighbouring TSOs, between neighbouring DSOs and between TSOs and connected DSOs, but can also involve transactions with market parties**.** For cooperation involving joint system operation, flexibility service providers are involved as they are the main parties providing services to the network operators. A market operator (independent or jointly owned by the network operators) may also be involved for procuring system services. For data exchange cooperation initiatives, an independent data hub manager may be set up, ensuring access to energy system data not only to network operators but also to market parties such as

[250] Rossi et al. (2020) TSO-DSO coordination to acquire services from distribution grids: Simulations, cost-benefit analysis and regulatory conclusions from the SmartNet project

suppliers and aggregators on a non-discriminatory basis, while ensuring privacy and cybersecurity requirements are met.

TSO/DSO cooperation **frequently involves non-financial transactions** (i.e. administrative or technical cooperation where a financial exchange does not take place). Even for the joint procurement of system services, transactions are mostly non-financial, involving for example cooperation for capacity calculation (in order to allow DERs to participate in the provision of system services), forwarding of DER bids, and joint market clearing. Depending on how settlement is organised, there may be a financial transaction from one network operator to the other (who will in turn pay the flexibility provider).

Information asymmetry between parties can be high for some transactions related to TSO/DSO cooperation – especially capacity calculation, where there might be information asymmetry between the network operators. **The regulation of TSO/DSO cooperation is typically high**, as network operators are, based on EU and national regulation, legally required to cooperate on a number of topics. Moreover, regulation of data exchange transactions is further justified by the need to ensure non-discriminatory access to relevant grid and market data, and to respect the rules regarding data privacy and security. Only the exchange of data on network connection capacity is at present less regulated, but more transparency and visibility in this domain could be beneficial, also to evaluate possibly required grid capacity reinforcements versus alternative solutions.

The transactions with the highest costs are those related to the management of the data hub and authorisation for access to data, and to a lower extent joint contracting of flexibility and ancillary services. While transactions related to grid and market data are mainly characterised by high IT costs for the data hub, transactions for ancillary services are mostly driven by tendering or bargaining, decision and implementation costs. This assessment of high costs for certain transactions is confirmed by the literature..

Transaction barriers identified by the literature (considering the sources listed in the table below) concern first the complexity of coordination between the TSO(s) and DSO(s), as, joint procurement of system services for both the transmission and distribution system levels require a precise scheduling of the different procurement steps, from capacity calculation to procurement, completion of financial transactions and delivery verification (and eventual penalisation of non-delivery). In addition, joint procurement as well as other forms of TSO/DSO cooperation (data sharing and connection-related activities) require significant data exchange, not only between network operators but also with other actors. Furthermore, an independent market operator may need to be established, which would require regulation as well as significant cooperation between involved parties, and create an additional party for transaction.

Flexibility registers and the Belgium FlexHub initiative[251]

Flexibility registers are seen as an important tool in facilitating the procurement of flexibility services by multiple actors, including TSOs and DSOs. According to the OneNet project, flexibility registers "facilitate information exchange related to the overall flexibility market framework and conducts processes related to asset information management and flexibility verification and settlement.".

In essence, any flexibility market will require functionalities common with flexibility registers. Data hubs are another category of initiatives related to flexibility registers. However, according to OneNet only the Belgium FlexHub initiative managed by Synergrid meets all the requirements to be considered a flexibility register, including qualification and management of parties, access management and data sharing, and other features.

FlexHub is a joint initiative of Belgium TSO and DSOs, currently used to procure balancing as well as congestion management services. The operator of the platform manages contact details from market parties as well as the completeness and integrity of all data in the platform, provides the necessary data for the market parties, and aggregates provided flexibility volumes at the required level.

6.4.7. Other barriers

The literature suggests that, aside from transaction barriers, regulatory barriers are the most common obstacle to TSO/DSO cooperation. Table presents the main barriers to TSO/DSO cooperation identified in the literature; several sources refer to the absence or slow development of appropriate regulation and standards (such as protocols for data exchange or definition of market products) necessary to enable cooperation. It must be noted that the literature mainly focuses on joint procurement activities by TSO/DSOs. Nonetheless, as TSOs/DSOs are regulated entities, it is logical that the absence or slow development of regulation affects TSO/DSO cooperation activities, as network operators typically require a mandate for cooperation as well as some form of authorisation to be able to recover the costs associated with their cooperation.

Market and technical barriers to TSO/DSO cooperation also exist. Market barriers relate especially to the investment levels required to implement some of the cooperation activities such as joint procurement of system services, as well as risks of strategic behaviour of market participants for the provision of services with a locational component. Technical barriers related to increase operational complexity to maintain reliability standards, and computation complexity (in the case of joint procurement).

[251] OneNet (2023) Flexibility register description and implementation D7.2

Table 17 Barriers for TSO/DSO cooperation[252,253,254,255,256]

Barrier type	
Regulatory	• Might be an important time lag between developing the TSO/DSO cooperation initiative and defining an adequate regulatory framework authorising the implementation • Lack of common rules for calculation and allocation of network capacity, such as cross-border capacity and from distribution to transmission networks • Absence of standardisation of market products which at the same time match the specific ancillary services needs of grid operators across the different areas and network levels • Regulatory framework needs to allow / provide mandate to network operators to develop common data hub and communication protocols that support data exchange and interoperability
Financial	• Significant investments in monitoring and control required for several cooperation areas
Technical	• Forecasting errors can affect market efficiency and thus benefits of joint procurement by network operators • Operational complexity to meet all reliability requirements can increase due to TSO/DSO cooperation • High computational complexity of network capacity calculations and market clearing • Complexity of market coupling hinders inter-TSO cooperation • Insufficient cross-border network interconnection hinders inter-TSO cooperation
Organisational	• Need to develop further expertise by network operators in TSO/DSO cooperation activities

6.5. Flexible network access solutions

6.5.1. Description of Solution

Traditionally, grid operators offer firm connection agreements to off-takers or producers requesting a connection. This means that grid users must be able to access the full 100% of the power capacity of their connection at any time. However, in reality, grid users do not use their full contracted grid capacity at all times, or might otherwise derive diminishing marginal utility from receiving higher amounts of power capacity (e.g., the first 5 MW of a grid user may be far more valuable to it than an extra MW expanding the capacity to 6 MW). In some cases, grid users may not even use their full contracted capacity at any point of the year, although grid operators must be able to honour the contracted capacity should it be required. As grid congestion becomes a critical issue in many European countries, more and more grid operators and NRAs seek to find connection options that impact grid capacity usage less and thus free up capacity for other users, while providing (as much of) the expected utility of a grid connection to a network user (as possible).

These "innovations in flexible network access" have received much attention in recent years, in response to multiple challenges. In addition to issues regarding grid congestion and congestion management, these innovations are intended to also alleviate the effects of large investment needs for grid infrastructure and long lead times for grid connections (discussed further in the next subsection). The solutions consist of different alternatives to the traditional firm connection agreement:

[252] IRENA (2020) Co-operation Between Transmission and Distribution System Operators - Innovation Landscape Brief
[253] Bridge (2019) TSO-DSO Coordination - BRIDGE Regulation WG and Data Management WG
[254] SmartNet (2019) Policy recommendations to implement and/or overcome barriers and enable TSO-ISO integration D6.3
[255] CEDEC et al. (2015) General Guidelines for Reinforcing the Cooperation Between TSOs and DSOs
[256] CEDEC et al. (2019) An Integrated Approach to Active System Management With the Focus on TSO – DSO Coordination in Congestion Management and Balancing

- **Flexible connection agreements**, which are the most used innovation. To our knowledge, in the EU-27 + NO, about a third of the countries apply flexible connection agreements, with only 4 countries offering some form of discount for the reduced service (FR, DK, BE, and NO).[257]
- **Time-dependent network access**, which only grants access to a higher network capacity at specific times. This can be done in multiple manners two of which are highlighted here: based on the time of day (e.g., Belgian DSOs setting night hours for network access) or based on peak/non-peak hours (e.g., Czechia and France DSOs automatically stopping some devices during peak hours).
- **Changes in network codes not requiring specific connection agreements,** such as the introduction of use-it-or-lose-it provisions or relaxing reliability standards;
- **Other forms of flexible network access**, such as guaranteed access for specific durations, for specific volumes of energy, or for specific minimum power capacity, etc.

As flexible connection agreements (FCAs) are the most common innovation being considered by various grid operators, we focus the analysis on this solution. Most other flexible network access innovations are new or are in a discussion or analysis stage (and thus, little insights are available on their potential impacts). Time-of-use tariffs are becoming more widespread, but as their effects are better understood they are also not analysed further. While FCAs find more use cases in practice in recent years, they still remain as a less-explored solution compared to other solutions considered in this report, such as DSF and digitalisation.

FCAs can be established for producers of electricity, consumers, and/or storage operators. In cases where FCAs are offered to producers, some regions opt to provide financial compensation in the case of down-regulation of the connection capacity (e.g., Wallonia) whereas others opt to not provide financial compensation (e.g., Austria).[258] Other benefits for the concerned grid users can also include discounted network tariffs or faster access to a grid connection.

Next to FCAs, some TSOs also use interruptibility schemes for existing grid users. Through these schemes TSOs can (partially or wholly) can activate downward demand response to achieve various system goals, including adequacy, ancillary services, and congestion management. These schemes were developed to large-scale industrial demand response into specific services for TSOs, and have mostly become replaced with wider DSF programs.[259] Most such programs across the EU have been phased out. Considering both the differing setup and addressed system challenges, and the general decline of these programs, we do not discuss these schemes further here.

ICAs are a non-market alternative for flexibility needs for grid operators. For DSOs, Article 32 of the Electricity Directive requires market-based procurement to be used as the primary means of accessing flexibility services. Thus, in cases where FCAs are considered, **NRAs must investigate whether a market-based alternative is a viable solution for their jurisdiction**. Moreover, in cases where this alternative exists, NRAs must be cautious about

[257] ACER (2023), Report on Electricity Transmission and Distribution Tariff Methodologies in Europe.
[258] CEER (2023), CEER Paper on Alternative Connection Agreements.
[259] ACER (2022), Market Monitoring Report 2020 – Electricity Wholesale Market Volume.

the potential loss of market participation from flexibility providers that have instead offered their flexibility within FCAs.[260]

6.5.2. Challenges addressed by the solution

Solution	Examples of sub-solutions	Higher complexity to identify system needs	Limited grid connection capacity	Limited cross-zonal capacity & low utilisation	Increasing congestion in networks	Increasing balancing needs	Non-frequency ancillary service needs
Innovations in flexible network access	Flexible connection agreements		T/D		T/D		
	Time-dependent network access		T/D		T/D		
	Changes in network codes		T/D		T/D		T/D

T/D: Transmission/distribution
High / medium / untested potential to address challenge

Three challenges are commonly used to justify the use of FCAs:

- **Limited grid connection capacity**: the primary justification for using FCAs is to increase the number of connections that can be offered to network users. Allowing for more flexible connections can give opportunity, especially on congested grids, for new grid users to get connected more quickly.
- **Large investment needs and long lead times for grid reinforcement**: FCAs improve the utilisation efficiency the grid, leading to lower needs for grid reinforcement, and the associated investment burden for network operators.
- **Congestion management needs**: FCAs directly impact the congestion in grids at various levels, and can thus be used as a tool for congestion management.

These three challenges and their impact are best exemplified by the Dutch grid's current state (as of early 2024), discussed next.

6.5.3. Example(s) of application

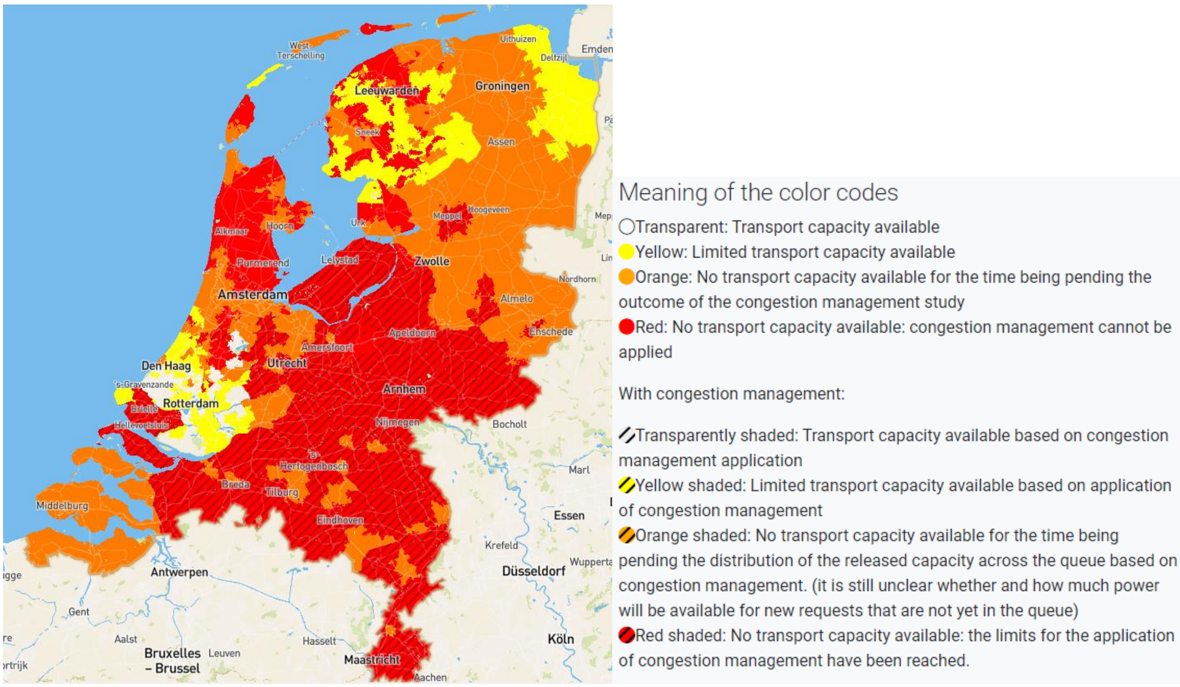
An example of FCAs can be found in the Dutch grid. The Dutch grid has been facing serious congestion issues, both as a consequence of ongoing electrification of industry, transport, and heating (i.e. rising demand) and increasing connections of distributed variable renewable electricity generation (i.e. changing supply). The situation has become especially concerning in recent years, as many renewable electricity producers and industrial users are facing long queues to receive a grid connection for their operations, with new connection requests not being currently accepted in many areas of the system.[261] Figure 26 illustrates the current situation, which, literally and figuratively, is rather red.

Recently, the NRA (Authority for Consumers and Markets, ACM), as part of a broader plan towards addressing congestion in the country[262], has approved the implementation of new non-firm connection agreements, as proposed originally by Netbeheer Nederland.[263] These agreements, referred to as non-firm connection and transport agreements (ATOs using the Dutch acronym), allow for both new and existing grid users to sign up for a non-firm connection agreement to the grid, in addition to the firm agreements previously available.

[260] CEER (2023), CEER Paper on Alternative Connection Agreements.
[261] RAP (2024), Gridlock in the Netherlands.
[262] EZK (2022), Landelijk Actieprogramma Netcongestie.
[263] https://www.acm.nl/nl/publicaties/codebesluit-non-firm-ato

In return, grid users can receive a discount on their network tariff. The plans for flexible connection agreements have been in development during 2022 and 2023, with stakeholder consultations leading to some changes in the original proposal. The final amendment of the network code has taken place in January 2024. In this final version, the NRA has agreed that during the following 12 months the option for a non-firm ATO may be implemented by the grid operators; i.e., during this period, grid operators are given discretion to offer non-firm ATOs or not. Rules for determining the penalties for violating non-firm ATOs are not yet included in the code, with such situations being handled on a case-by-case basis.

Figure 26 Map of capacity availability for offtake of electricity (similar congestion pattern can be observed for injection as well), updated February 2024. Source: Netbeheer Nederland website.[264]



The Regulatory Assistance Project also identifies a number of specific applications of flexible network access solutions (and other approaches) in various markets. An extract is shown below, and the reader is referred to the toolbox page for more details.[265]

[264] https://capaciteitskaart.netbeheernederland.nl/
[265] https://www.raponline.org/toolkit/rip-first-come-first-served/

Figure 27 RAP's identified options for increasing utilization of existing grid capacities

Utilizations of existing grid capacities		
OPTIONS AND IMPLEMENTATION TIME	**DESCRIPTION *AND RELEVANT EU LEGISLATION***	**EXAMPLES (REGULATIONS + PROJECTS)**
Shared connection / hybridization / colocation / pooling	Sharing of a single connection point to utilize the complementarity of resources and better use of land. This transfers the optimization of grid use from the network operator to users.	NL: Allowing storage in cable pooling, next to wind and solar. PL: Pooling of two or more renewables. DK: Joint location for generation and consumption. US: Allowing more than one generating facility to co-locate behind the same point of interconnection and to share an interconnection request. AUS: Allows for a combination of all technologies sharing a single connection point. ES: Allows hybrid facilities, provided that at least one is renewable or storage.
Setting up a congestion management platform	Organised platforms for network operators to procure flexibility for congestion management.	NL: Redispatch platform operated by the TSO and DSOs and integrated to energy trading platforms. UK, IT, FR, NO and SE: Flexibility marketplace for DSOs.
Mobilising participation in congestion management	Engaging additional grid users to offer their flexibility. Awareness-building on the revenue option.	NL: Mandatory participation above 1 MW. NL: Education of current grid users on their flexibility potential and value.
Alternative connection contracts	Limiting continuous access to grid, such as through fully flexible connection agreements, time-limited firm connection agreements or any combination of the two. *Alternative connection contracts in Europe have been considered temporary solutions until grids are upgraded and/or local flex markets – are developed (ED Art 32 of 2019). The **EU Action Plan for Grids** and the EMD agreement of 2023 consider them as potentially permanent features.*	DK: Interruptability in return for a reduced tariff for transmission-connected demand consumers. NL: Capacity limitation contract on top of existing firm connection contract. UK: Non-firm contract option for storage so that they can be limited also in case of intact network conditions.

6.5.4. Costs of the solution

The costs and benefits of FCAs are not, to our knowledge, directly reported in the literature. While some regulators and grid operators, such as those in Belgium, review the justification of FCAs via case-by-case cost-benefit analyses, no quantitative public information has been found on these assessments.

We identify both direct and indirect costs for the use of FCAs. Direct costs involve the decision process for codes on flexible connection agreements, and the implementation of FCAs by grid operators and NRAs. Both these costs are perceived to be rather small, in comparison to other solutions, especially those requiring hardware.

On the grid users' side, there will be almost always a lower utility from an FCA compared to a firm connection agreement. Nonetheless, grid operators will in general reward the concerned producers (possible curtailment of injection) or consumers (reduced available network capacity during a limited number of hours), either through reduced tariffs or through direct financial compensation when curtailment exceeds a pre-agreed number of hours. Moreover, network users have a diminishing utility for their connection capacity, meaning their welfare loss will be lower in case of a curtailment of connection capacity on the margin. Therefore, the net economic utility losses from switching to an FCA are expected to be low.

Indirect costs of FCAs are generally perceived to be much higher than direct costs. These costs mainly relate to the principle of using FCAs, while one could expect that the role of the grid operator in liberalised electricity markets is to timely invest in grid capacity, in order to be able to offer a firm connection agreement to all grid users. Implementing FCAs may delay the energy transition and have an impact on market competition, as some grid users would not be able to benefit of a firm connection agreement. The primary role of the grid operator in liberalised power markets, in addition to ensuring security of supply, is to enable the market access of market participants by providing reliable and firm grid connections. As electricity access is an essential service, grid operators are in general tightly regulated entities required to provide reliable connections and ensure non-discriminatory and transparent market access for all participants. Creating the option for flexible (non-firm) grid connections can impact the market access of participants, creating possible discrimination and lack of transparency. This is indeed one of the primary complaints of market parties in public consultations on FCA proposals, including in Belgium[266] and the Netherlands.[267] This can become especially an issue in highly congested areas, where FCA connections are expected to be implemented more frequently, leading to potentially discriminatory market access.

A pressing issue is that the same challenges tackled by FCAs are already addressed by congestion management, via better-developed market-based procurement to meet the specific grid operators' needs. Many of the benefits potentially provided by FCAs can be captured by well-designed competitive procurement of congestion management (open to all eligible market parties, and thus potentially less discriminatory), while the existence of FCAs interacts with the functioning of these procurement mechanisms. But congestion management services may not provide the necessary certainty to free up network capacity that in turn allow to offer new firm connection agreements. Therefore, a central question is whether new connection agreements can be offered through other means, or if FCAs are necessary when networks are highly congested. Such a fundamental change in the structure of the electricity system can have far-reaching consequences for all market participants, and should thus be carefully evaluated.

6.5.5. Benefits of the solution

The benefits of flexible connection agreements are:

- For the grid operator, there is a more efficient use of the grid. Lower peak network capacities can be allocated to flexible connections depending on when and where the connection is used, and thus more grid connections can be made available without network investments. This can improve grid utilisation, while reducing lead times for higher-voltage connections and reducing the need for grid expansion.
- For the connected grid user, who can benefit from a lower network tariff (or other financial compensation) for its constrained use of the grid for electricity off-take/injection. The actual benefits for grid users depend on the effective curtailment of injection or offtake and the actual network tariff discounts or financial compensation being provided/applicable.
    - More indirectly, another benefit can be faster access to the grid, when an FCA is used. This indirect benefit is indeed the main advantage considered in the Belgian and Dutch cases.

6.5.6. Transaction costs

Transactions for FCAs consist of:

- **Definition of terms and conditions**, performed by the TSO/DSO together with the NRA, with participation of various stakeholders during consultations.

[266] https://www.elia.be/en/public-consultation/20230714_public-consultation-on-the-design-note
[267] https://www.acm.nl/nl/publicaties/codebesluit-non-firm-ato

- **Contracting of flexible grid connection/access agreements**, which are negotiated and concluded between TSOs/DSOs and grid users, with oversight (and sometimes direct involvement) from NRAs.

Definition of terms and conditions for FCAs by TSOs/DSOs generally falls into the regulatory mission of each national regulator, where necessary underpinned by ad-hoc legislation to clarify the rights and obligations of each concerned party. These procedures are in general defined well in advance, and most entities acting in this area are well-acquainted and capable in the relevant interactions. Overall, B&D and P&E costs are considered to be low, although the development of the regulatory framework and processes might be more burdensome. Important aspects that need to be considered for the development of a regulatory/legal framework for FCAs are: [268]

- Relationship with other procurement methods for flexibility, particularly local flexibility markets.
- Financial compensation scheme (versus firm connection agreements), which can be non-existent, discount on network access tariffs, discount on grid connection fees, or other forms of compensation based on the actual missed revenues of grid users.
- Geographical scope, namely where FCAs can be concluded, such as limiting their use to areas with structural or occasional congestion.
- Scope of system users that are eligible for FCAs, namely consumers (off-take from the grid) and/or producers (injection) or battery operators (bi-directional).
- Contract duration, conditions for termination.

Considering the multiple and diverse factors listed above, and the wide-ranging economic and technical impacts of these arrangements on both individual grid users and on the overall electricity system, the S&I costs for these agreements can be high.

Once the conditions are defined and set as national rules (e.g., as a network code in the Netherlands[269]), FCAs can be contracted between network operators and grid users. In some cases, specific conditions in the rules may require the NRA to directly participate in the contracting process. For example, in Belgium, the national or regional regulatory authority can in some cases be required to perform a cost-benefit analysis to determine the appropriateness of an FCA.[270] The preparation, negotiation and contracting of these agreements entail very high S&I costs for the concerned parties; moreover it is quite difficult to objectively determine the costs and benefits of these agreements. This is especially true for consumers. Reasons include:

- Grid users may not be able to forecast their electricity connection needs over a long time period (as determined by the contract duration of FCAs).
- Grid users may not be able to directly compare the compensation they receive via the FCAs (network tariff reduction, etc.) to alternative means of monetising their flexibility (for example via local or regional markets)
- Grid users may not have sufficient clarity regarding the connection time for firm versus non-firm connection agreements, and/or conditions for transfer from one

[268] CEER (2023), CEER Paper on Alternative Connection Agreements.
[269] https://www.acm.nl/nl/publicaties/codebesluit-non-firm-ato
[270] CEER (2023), CEER Paper on Alternative Connection Agreements.

connection type to another (e.g., the availability of firm connections following network development)

- Network operators may miss sufficient understanding about the actual (amount and timeline of) benefits of FCAs, and may face difficulty in ascribing related compensations for end-users.
- (when needed) NRAs may lack the adequate information or internal capabilities to properly evaluate the appropriateness of FCAs on an individual basis, such as via an assessment based on a CBA.

Unlike S&I costs, B&D and P&E costs depend greatly on the legal/regulatory framework set up in the concerned country, and on the specific electricity grid and market situation in the region where the FCA is implemented. Overall, these costs are perceived to be lower than the S&I costs. Based on the current rules for FCAs (such as the Dutch ATOs) we find that transaction costs attributable to P&E actions can be elevated, as legislators/regulators are hesitant about prescribing specific penalties for breaching of contracts, thus requiring enforcements on a case-by-case basis.[271]

FCAs applied by the Danish DSOs[272]

Denmark has developed an FCA scheme at the DSO level. Following initial pilot cases between 2012-2014, in 2015 the Danish energy industry association *Green Power Denmark* developed, together with the NRA *Forsyningstilsynet*, a standardised approach to FCAs. In the latest version[273], the scheme has expanded to include both generation and demand assets. Some limitations on size exist: demand assets exclude households, due to high transaction costs along with limited benefits, and generation assets exclude assets below 1 MW capacity.

FCAs are allowed in both congested and non-congested areas. In return for a flexible connection, grid users receive discounts on the grid connection charge. The following design choices in this FCA scheme present reductions in transaction costs:

- Grid users are allowed to switch to a firm connection agreement if needed, based on an agreement with the DSO (i.e. dependent on costs and timeline)
- FCA should not trigger additional network development, upstream of the individual connection and associated digital infrastructure. Moreover, in cases where this is needed, the grid user must switch to a firm connection agreement first.
- The DSO has some (non-binding) requirements for FCAs:
    - The DSO is expected to provide an estimate of the number of hours with curtailment throughout a year.
    - The FCA is expected to contain a thorough assessment and details on the uncertainties surrounding its grid access following the connection.
- For generation assets, the DSO must be able to control generation with its existing SCADA system.
- Grid users with FCAs can participate in TSO flexibility markets, but not in DSO flexibility markets. They also have full access to wholesale and balancing markets.

[271] See for example stakeholder input on the Dutch rules, available at https://www.acm.nl/nl/publicaties/codebesluit-non-firm-ato
[272] Thema Consulting Group (2022), Conditional connection agreements - A literature review.
[273] Green Power Denmark. (2022). Vilkår og betingelser for tilslutning med begrænset netadgang for produktionsanlæg

6.5.7. Other barriers

Connection agreements are in general highly regulated. The primary barriers preventing the implementation of FCAs (aside from high transaction costs) are regulatory in nature.

The first "barrier" is that in a few cases, national rules in the EU-27 may explicitly prevent FCAs. As of May 2023, Finland and Luxembourg's legal rules on connection agreements require a firm connection is offered to every (potential) grid user. In practice, however, some derogations have been given in both countries, on a case-by-case basis. Considering the possibility of derogations, this barrier is not considered as a significant issue for the implementation of FCAs across the EU-27 in the future.

The second regulatory barrier relates to EU-wide rules and may be more significant. Specifically, Article 32 of the Electricity Directive's (EU) 2019/944 requires DSOs to procure their flexibility needs, including congestion management, via market-based, transparent, and non-discriminatory methods. Derogation should only be allowed in cases where "[market-based procurement] is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion." As FCAs provide "flexibility" via a method that is in principle not market-based, and often comprise design elements that make them less transparent or more discriminatory than flexibility markets, transposing this Directive provision as such in national rules could create a more difficult regulatory framework for FCAs.

Table 18: Barriers for flexible network access (FCAs)

Barrier type	
Regulatory	• In very few cases, national rules explicitly prevent FCAs. As of May 2023, this was the case in the EU-27 only of Finland and Luxembourg. It is worth however noting that both these countries have allowed one or more derogations.
Regulatory	• EU rules (Electricity Directive, Art. 32) require that DSO flexibility should be procured via market-based methods. Thus, only in cases where market-based methods are unviable are FCAs to be used.

6.6. Time and location-differentiated grid tariff signals

6.6.1. Description of the solution

In principle, tariffs are structured by three components: energy component (€/kWh, also named "volumetric" component), a power or capacity component (€/kW) and a fixed component (€/year). [274]

One of the solutions to reduce congestion risks and investment needs is the adoption of time and location-differentiated grid tariff signals in the energy and/or in the capacity component. These pricing mechanisms aim to incentivize users to adjust their network usage patterns in response to fluctuations in both **time** and **location**-specific grid conditions. Dynamically pricing tariffs based on factors such as demand levels, renewable energy availability, and grid congestion promotes efficient utilization of resources and facilitate the integration of renewable energy sources into the grid.

[274] CEER (2020) CEER Paper on Electricity Distribution Tariffs Supporting the Energy Transition

Time-of-use (ToU) network tariffs depend on **when** the service is used, such as during peak/off peak hours, season, month, weekdays and weekends. ToU charges provide clear signals to users within the network to adjust their usage patterns, promoting reduced utilization during peak periods and increased usage during off-peak times. These charges are structured to reflect the varying levels of network demand throughout the day, week, or year. During periods when network utilization approaches its technical capacity, charges are set higher to discourage excessive usage, thereby mitigating the risk of overloading the network. This strategy helps to avoid the need for costly network reinforcements by managing demand during high-congestion periods. Conversely, during off-peak periods when network usage is lower and additional costs are not incurred, lower charges are applied to incentivize utilization, ensuring efficient use of resources and infrastructure.

ToU charges are either static or dynamic; static charges entail predefined time periods established well in advance, often during the initial formulation of tariff methodologies or on an annual basis. Conversely, the peak period in dynamic charges is determined close to real time, e.g., a day in advance or within the day. The dynamic approach allows for a more accurate reflection of current system conditions, providing timely adjustments to pricing structures. However, the trade-off for this responsiveness is increased unpredictability for network users, who may face challenges in anticipating peak periods and adjusting their usage accordingly.[275] Furthermore, the implementation of ToU tariffs are dependent [276]on the roll out of automation devices such as smart meters, controlling devices for household appliances and electricity price communicators.

Network tariffs can also depend on the **location.** The variation of the network costs may depend on the users density, the distance from generation or demand, the network asset profile and characteristics (meshed/radial, overhead/underground), and the differences in the short-term marginal costs due to utilisation or spare capacity, of the network. In principle, locational access tariffs can be either **nodal**, based on load flow models, **zonal**, based on geographical regions and **archetypical**, based on the users characteristics (such as population density).[277] However, the implementation of locational access tariffs presents several limitations, including limited knowledge of the network (e.g., assets, network loads), differences in calculations for LV and EHV, and public acceptance and fairness of charging different prices across different regions within the same country for the same services. [278]

In addition to locational access tariffs, other instruments exist in order to provide locational signals to network users. These include the review of the bidding zone configuration (in the case of nodal systems), locational connection tariffs, and the use of locational criteria in auctions (e.g. for allocation support to renewable electricity or hydrogen production or for implementation of capacity mechanisms).[279]

[275] ACER (2023) Report on Electricity Transmission and Distribution Tariff Methodologies in Europe
[276] ENEFIRST Using time-of-use tariffs to engage costumers and benefit the power system
[277] CEER (2020) CEER Paper on Electricity Distribution Tariffs Supporting the Energy Transition
[278] Ibid.
[279] JRC (2024) Redispatch and congestion management

6.6.2. Challenges addressed by the solution

Solution	Examples of sub-solutions	Higher complexity to identify system needs	Limited grid connection capacity	Limited cross-zonal capacity & low utilisation	Increasing congestion in networks	Increasing balancing needs	Non-frequency ancillary service needs
Time-of-use and locational network tariffs	Time-of-use tariffs		**T/D**		**T/D**		
	Locational tariffs		**T**		**T**		

T/D: Transmission/distribution
High / medium / untested potential to address challenge

The implementation of time and location differentiated network tariffs could alleviate three main challenges, namely:

- **Large grid investment needs and long lead times for network reinforcement:** this approach incentivize the users to shift their electricity usage away from peak periods and towards times of lower demand, therefore flattening demand peaks and reducing strain on the grid. Additionally, by encouraging consumption in areas with surplus capacity and during off-peak hours, these tariffs optimize the existing infrastructure's efficiency. Consequently, the need for costly grid investments and network reinforcement to accommodate peak demand can be mitigated, as the grid operates closer to its optimal capacity.
- **Limited grid connection capacity and congestion management:** the adjustment of the electricity usage to off-peak hours and regions with available capacity alleviate the strain on congested areas of the grid. Additionally, by accurately reflecting the varying costs associated with grid usage at different times and locations, these tariffs encourage more efficient distribution of electricity, reducing the likelihood of congestion.

6.6.3. Example(s) of application

Time-of-use signals

At transmission level, five countries (HR, FR, PT, SI, ES) are implementing ToU signals in both energy and capacity components, two only for the energy based component (EE, FI) and two for the capacity based component (BE, GR). At distribution level , more than half are implementing ToU signals only for the energy component (AT, BE , EE, IE, LV, LT, MT, NL, NO, PL, SK) and about 40% in both components (HR, CZ, DK, FI, FR, PT, SI, ES, SE). Only Greece applies ToU signals only for the capacity component.

Figure 28 Use of Time-of-use signals across Europe

		AT	BE[135]	HR	CZ	DK	EE	FI[136]	FR	GR	IE	LV	LT	MT	NL	NO	PL	PT	SK	SI[137]	ES	SE
Transmission	Energy based			●			●	●	●							●		●		●	●	●
	Power based		●	●					●	●								●		●	●	
Distribution	Energy based	●	●	●	●	●	●	●	●		●	●	●	●	●	●	●	●	●	●	●	●
	Power based			●	●	●		●	●	●								●		●	●	●

Note: No ToU tariffs apply in BG, CY[138], DE, HU, IT, LU, RO. Grey dots in case of NO and SE signal the market based elements.

Source: *ACER (2023) Report on Electricity Transmission and Distribution Tariff Methodologies in Europe*

Textbox 1 Transmission level time-of-use signals in Portugal

Portugal

A pilot project from June 2018 to May 2019 investigated changes to the time-of-use structure for large consumers, resulting in a new scheme characterized by intensified pricing signals during peak periods and regional differentiation of time-of-use schedules across three grid areas. A cost-benefit analysis projected a net benefit of 50 million euros over 23 years, primarily driven by a 2.2% demand response during super peak periods, leading to reduced or deferred network investments. Examination of VHV and HV consumers revealed strategic consumption patterns aimed at avoiding peak prices, particularly notable in VHV where consumption was lowest during peak periods, contributing significantly to system peak reduction. This suggests successful alignment between tariff incentives and consumer behaviour, yielding both cost savings and enhanced grid stability.[280]

Location signals

On the other hand, the application of locational signals across Europe is less popular, with only 5 countries and 6 jurisdictions (Austria, Ireland, Northern Ireland, Norway, Sweden and Great Britain) implementing them at transmission level. All jurisdictions except Austria are applying the locational signals to the injections charges of generators, while Austria, Norway, Sweden and Great Britain are implementing them at the exporting charges of users.[281]

[280] ACER (2023) Report on Electricity Transmission and Distribution Tariff Methodologies in Europe
[281] ACER (2019) ACER Practice Report on Transmission Tariff Methodologies in Europe

Norway

The Norwegian Transmission System Operator (TSO) implements a locational charge to account for marginal losses incurred throughout the system, recalculated weekly to accommodate changing system conditions. At connection points where energy is both taken from and fed into the system, loss rates are symmetrical around zero. In areas with an excess of energy input, positive loss rates apply to input and negative rates to output, and vice versa. These marginal loss rates are capped at 15%. Additionally, outtake from the transmission network incurs charges consisting of an energy component based on marginal network losses and a fixed component determined by proximity to power production plants and the potential load that can be disconnected within a specified response time.[282]

Denmark

Denmark introduced a producers charge in 2023, which is based on geographical differentiation and delimitation of the production and consumption areas that both influence the size of the charge. Additionally, a one-off connection fee was also introduced for the producers that is also differentiated by the location of the production plant. The guidelines categorize the costumers in seven groups based on their connection points and in three geographical zones (red/yellow/green) determined by the available grid capacity. In the red zone, it is assumed that the grid company must expand grid capacity by 95% of the producer's input, while in yellow and green zones, this assumption decreases to 50% and 10%, respectively. Connection fees are waived for production plants of 50 kW or less if the customer is a self-producer. Additionally, in some instances, fees are reduced for production plants and self-producers, reflecting a tailored approach to incentivize renewable energy generation and self-sufficiency. [283]

6.6.4. Costs of the solution

Excluding the costs that are required to roll out smart meters, the implementation of locational and time-differentiated network tariffs in principle has low costs. These are mainly administrative and communication costs (design, implement, report, communicate and manage the tariffs) and potentially some compliance costs (conducting studies to ensure that the network tariffs comply with the regulatory and legal requirements). However, these costs are not reported in the literature, therefore it is challenging to estimate the exact costs of this solution.

6.6.5. Benefits of the solution

- **Grid Optimization:** Time and location-differentiated tariffs provide a mechanism for incentivizing consumers to shift their electricity usage away from peak periods and congested areas of the grid. By offering lower prices during off-peak hours and in regions with surplus capacity, these tariffs encourage more evenly distributed consumption patterns and therefore reducing the need for infrastructure upgrades.
- **Efficient resource allocation:** reflecting the true cost of electricity consumption based on factors such as time and location, differentiated tariffs promote more

[282] https://www.nve.no/norwegian-energy-regulatory-authority/network-regulation/network-tariffs/
[283] https://poulschmith.com/news/producer-charge-for-the-grid-connection-of-re-production-plants-from-2023

efficient resource allocation within the energy system. Consumers are incentivized to adjust their usage patterns to align with times of lower demand or higher renewable energy generation, thus reducing the overall strain on the grid. This not only improves the reliability and stability of the grid but also minimizes wasteful consumption and maximizes the utilization of available resources.

- **Renewable energy integration:** By incentivizing consumption during periods of high renewable energy generation, such as sunny or windy days, these tariffs help to balance supply and demand more effectively. This, in turn, reduces the need for curtailment of renewable energy generation and supports the transition to a more sustainable and environmentally friendly energy system.
- **Consumer empowerment:** Differentiated tariffs empower consumers by providing them with greater control over their energy usage and bills. By offering price signals that vary based on time and location, consumers are encouraged to adopt behaviours that not only benefit them financially but also contribute to grid stability and sustainability. This may include shifting energy-intensive activities to off-peak hours or investing in energy-efficient technologies to reduce overall consumption.
- **Congestion management:** Time and location-differentiated tariffs help to mitigate congestion by directing consumption to areas with available capacity and incentivizing consumers to adjust their usage patterns accordingly. By reducing the likelihood of overloading critical grid infrastructure, these tariffs contribute to improved grid reliability and minimize the risk of blackouts or disruptions.
- **Cost savings:** By offering lower prices during off-peak hours and in regions with surplus capacity, consumers can take advantage of more affordable electricity rates. This reduces individual energy bills and incentivizes more efficient energy usage, leading to long-term cost savings for both consumers and the energy system as a whole.

6.6.6. Transaction costs

The main transaction costs identified for the temporal/locational network tariffs regard:

- The methodology development;
- Setting the tariff values;
- The transmission of pricing information; and
- The reaction of network users to the tariffs.

Transaction costs emerge in the **methodology development** of temporal/locational network tariffs. The main actors involved are the network operators or national energy ministries responsible for the development of the methodology and the NRAs that supervise and approve the methodology. These interactions occur usually every 4 to 5 years, yet it is highly dependent on the jurisdiction (for instance in Italy and Finland the tariff methodology is in principle reviewed every 8 years).[284] However, the fact that the involved parties might have different priorities (e.g., the network operators' objective is cost-recovery and fair equity remuneration while the ministry and NRA may focus on fair and non-discriminatory cost allocation among others), may lead to additional transaction costs. NRAs need to approve and monitor tariff settings and the revenue caps for network operators , as well as to define which costs can be recovered by network tariffs, and the basis for their recovery (e.g. used or contracted peak capacity or energy volumes). This

[284] ACER (2023) Report on Electricity Transmission and Distribution Tariff Methodologies in Europe

process may be subject to a medium level of information asymmetry between NRAs and network operators (e.g., on the costs factors that the network operators are sharing). Additionally, before the approval of the methodology, one or multiple rounds of public consultation should be organised by the network operators with the main market parties and stakeholders, including relevant authorities of each MS that should last at least for a month.[285] Considering the increased participation of end-users in electricity production, storage and demand response, the interest and involvement of grid users in the public consultations is expected to increase.

As network costs are mostly capacity related, a large cost share should, in principle, be recovered via capacity-based tariffs. However, when setting tariffs NRAs and network operators should consider that capacity-based charges may negatively influence grid users with a low load factor. On the other hand, volumetric (energy based) network tariffs may over-incentivise prosumers who might pay less than their fair share, in particular if injection and offtake are compensated.[286] Those transaction costs are mostly related to S&I which are expected to be high and to represent a medium share of the overall transaction costs.

Setting tariff values occurs in general on a yearly basis and involves transactions between various stakeholders. Setting temporal/locational network tariffs is a highly complex process due to changing load profiles, the increasing integration of DERs and storage and the need to respect the tariff design principles (specifically non-discrimination, cost-reflectiveness and transparency). Furthermore, in order to ensure that the temporal/locational tariffs are cost-reflective, NRAs should obtain granular data from the network operators regarding the load and injection profiles, average and peak utilisation per representative category of grid, user frequency and duration of grid congestions, number of network users per representative category, etc., which increases the transaction costs, mainly the S&I costs.[287] Furthermore, the actual CAPEX and OPEX levels of network operators will be different than the forecast within grid development planning, which makes it challenging to establish tariffs for the upcoming year.

Having access to the most accurate and detailed information is hence key. In tariff setting, there is (medium) information asymmetry between grid users, NRAs, and network operators. High S&I transaction costs may be involved, albeit setting tariff values for simples schemes such as time-of-use tariffs may be simpler.

Transaction costs emerge also from **transmitting network tariff and grid/market information** from network operators to market parties including end-users and prosumers at a sub-daily basis, in the case of dynamic tariffs. These transactions involve some S&I costs for network operators to collect and share data (actual generation, consumption, congestion, etc).

Finally, the **reaction of network users** to temporal/locational network tariffs may in some cases entail (high) transaction costs mainly involving network operators and network users, especially S&I costs. Grid users should understand their grid use patterns (offtake and/or injection) and the impact of the different tariff components and subsequently adapt their grid use (electricity consumption, storage) in order to benefit from the differentiated tariff components throughout the day. This requires some effort and time from their side which

[285] Commission Regulation (EU) 2017/1485
[286] Eurelectlc (2021) Powering the Energy Transition Through Efficient Network Tariffs
[287] Ibid.

can be rather significant; this process can however be automated via tariff signals directly sent to appliances or processes. Additionally, behavioural adjustment costs may involve investing in smart equipment, or altering daily electricity use routines. Moreover, transaction costs can arise from administrative burdens, such as more frequent and or complex billing processes and arrangements between network operators and grid users, monitoring usage data, and reconciliation and settlement etc, creating some B&D costs at a moderate level. In this case, there can be a high level of information asymmetry as grid users may lack adequate information on tariff structures and actual levels, and their grid use patterns. Finally, consumer's lack of interest in demand response and a preference for fixed-price contracts over incentives for adjusting consumption during peak periods exists in Europe and constitutes a cost for the implementation of time-differentiated and locational network tariffs. Despite the potential financial benefits of dynamic pricing, such as rewards for demand response, many consumers prioritise the predictability and consistency offered by fixed contracts, thereby hindering their engagement with flexible pricing schemes.

We must also note that the transaction costs across all transactions is higher as a network tariff becomes more complex. It is relatively easier to agree on methodology, to set tariffs, to transmit signals, and to react to signals, when a simple network tariff with a fixed price is used. A more complex network tariff with dynamic (time) pricing and/or locational price factors can greatly increase transaction costs for all transactions. We considered in this analysis mainly simpler tiered time-of-use pricing, and note that other pricing options are more difficult to use with higher transaction costs.

ToU tariffs in France

France has been using ToU and variable-peak tariffs for 50 years to several voltage levels. The implementation of the ToU tariffs produce daily peak savings of 10GW in summer and 20 GW in winter, as well as seasonal peak savings of around 40 GW between summer and winter thanks to the use of electrical heating.

At the medium voltage level, the network tariffs are split in five time periods namely annual peak, high season peak, high season off-peak, low season peak, low season off peak, whereas the annual pick can be either fixed or variable and can be selected by the end user. A similar structure is also adapted for large users.

At low voltage level on the other hand, the periods are split in four and there is no variable peak. [288] For residential consumers some suppliers, such as Engie, have introduced a daily 8-hour window off-peak (usually between 22:00-06:00) when the tariffs are lower. This contributes to shifting part of the peak consumption towards less intensive periods of the day. Additionally, in the contract with the supplier and in the electricity bill the different rates of network tariffs are clear so that the consumers are aware on the time that is more profitable to use the network. [289]

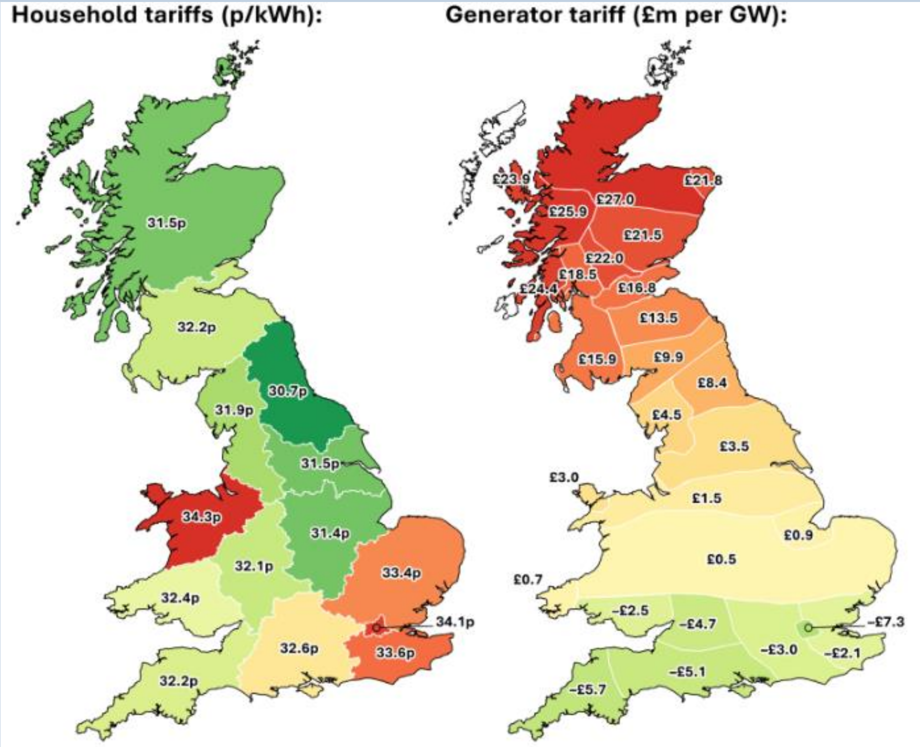
[288] CEER (2020) CEER Paper on Electricity Distribution Tariffs Supporting the Energy Transition
[289] Engie (n.d.) Peak Hours / Off-Peak Hours

Locational tariffs in the UK

The UK implemented locational differentiated network tariffs to generators for injecting energy at transmission level and to consumers for withdrawing energy at distribution level. While users are paying different prices depending on the region they live, users living in the same area, which are managed by the same distribution network operator, have a common tariff regardless of how remotely the household is located.

This policy can alleviate the constrains of the grid by incentivising more generators to provide capacity when prices are high (high demand) and respectively turn down their output when prices are low (low demand). At the same time, consumers that live in remote areas are not penalised with different prices therefore ensuring fairness among consumers.

Figure 29 Regional variation of the network tariffs for households (left) and generators (right) in the UK (Q3 2022)



Source: *Drax (2022) Drax Electric Insights Quarterly – Q3 2022*

6.6.7. Other barriers

One significant barrier identified in various literature sources for the implementation of temporal network tariffs is the lack of widespread roll-out **of smart meters and enabling smart equipment** along with the relatively high costs, especially in the residential sector. While the penetration rates of smart meters are increasing across Europe, the overall level is still (very) low in 50% of the EU MSs. In 2022, 13 European countries had a smart meter penetration rate of more than 80% (namely SE, DK, FI, EE, ES, NO, LU, LV, IT, FR, MT, SI, NL), while 5 countries (BG, CY, CZ, DE and GR) had not yet started a systematic roll out of smart meters. In 6 countries (BE, HR, PL, SK, LT and HU), the penetration rate ranged between 7%

to 20%.[290] The delay in the smart meters' roll-out which would enable load management may be partly related to the CAPEX-bias, meaning that network companies prefer to invest in extending the electricity network capacity, rather than investing in smart meters which may not create high returns for the network operator.[291]

6.7. Microgrid solutions

6.7.1. Description of Solution

Microgrids are **localised power systems** that can operate independently of the main electricity grid. They are also defined as '*integrated systems in which distributed energy resources (DERs) create a grid that feeds a variable number of distributed loads. Both elements constitute the main body of a microgrid.*'[292]

Depending on the type, they serve specific areas, such as individual buildings, industrial parks, university campuses, or neighbourhoods. These small, self-contained grids connect multiple assets that generate, store, and use electricity within their boundaries, providing resilience and flexibility. Most microgrids generate their own power using renewable energy (wind and solar energy).

Microgrid research in the EU is rising, and a project[293] has mapped decentralised energy systems that could qualify as microgrids in the EU (see Figure 30).

- Green location marks: existing microgrids
- Blue location marks: microgrids under construction
- Orange location marks: potential microgrids but information is lacking
- Red location marks: planned, but not developed

[290] ACER (2023) Energy Retail and Consumer Protection- 2023 Market Monitoring Report
[291] Brunekreeft, G., & Rammerstorfer, M. (2021). OPEX-risk as a source of CAPEX-bias in monopoly regulation. Competition and Regulation in Network Industries, 22(1), 20-34. https://doi.org/10.1177/1783591720983184
[292] Planas et al. (2015) AC and DC technology in microgrids: A review
[293] Microgrids-Research.eu

Figure 30 Microgrids EU map

Types of microgrids:

Microgrids can be in AC (alternating current), DC (direct current), or a hybrid form. Some of their properties differ, including their control architecture and systems. A comparative study has concluded that DC technology offers several advantages, compared to AC grids, especially for longer distances.[294]

DC microgrids are gaining prominence due to their efficiency and suitability for specific applications and they are particularly useful in scenarios like **data centres, transportation electrification, and off-grid applications. Advantages of DC Microgrids include**:

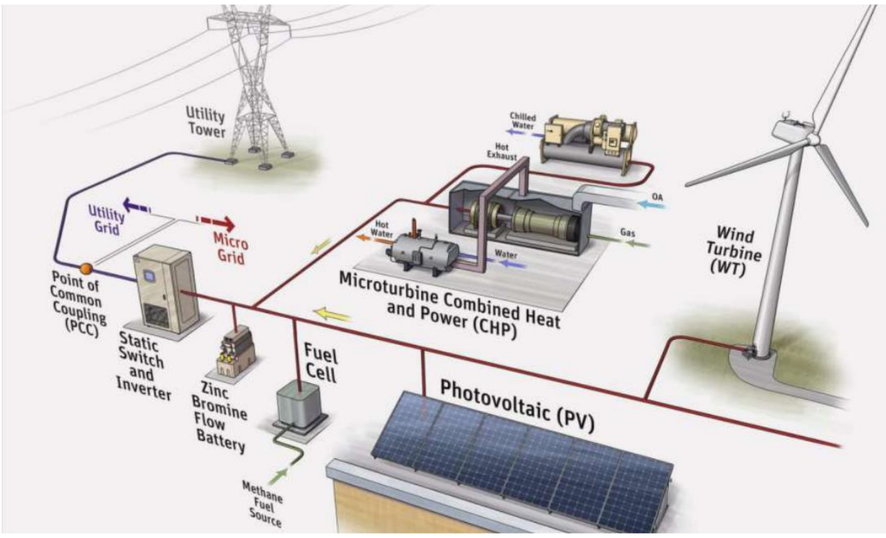
- Energy efficiency: DC systems have lower conversion losses compared to AC systems, especially when integrating renewable sources.
- Modularity: DC microgrids can be easily expanded or modified.
- Resilience: They can operate independently during grid outages, enhancing reliability.
- Integration with renewable energy: DC grids seamlessly accommodate solar panels and other DC-based sources.
- Reduced infrastructure costs: DC systems may require less complex and costly infrastructure than AC grids.

[294] Microgrids: A review, outstanding issues and future trends - ScienceDirect

In its 2050 vision for a carbon-neutral electricity system[295], ENTSO-E identified microgrids as a potential 'game changer-technology', pointing out that this solution might be key in the future but will emerge later in time compared to traditional solutions. Prosumers and microgrids are already impacting market patterns, while they help reduce grid flows and support grid operation and resilience through their multi-level control methods.

As shown on Figure 31 microgrids can serve a variety of assets and connections, while also being able to connect/disconnect from the public grid with a switch, operating in synchronised or islanded mode.

Figure 31 illustration of a microgrid with various connected assets[296]



6.7.2. Challenges addressed by the solution

Solution	Examples of sub-solutions	Higher complexity to identify system needs	Limited grid connection capacity	Limited cross-zonal capacity & low utilisation	Increasing congestion in networks	Increasing balancing needs	Non-frequency ancillary service needs
Microgrids	AC/DC microgrids		D		D	T	D

T/D: Transmission/distribution
High / medium / untested potential to address challenge

High network investment needs: Microgrids facilitate the integration of renewable energy sources at the local level, and hence reduce the need for investments in grid capacity. They allow for optimal energy management by matching local supply with demand, including via demand flexibility and storage. They can also offer additional flexibility services to the power system, especially if equipped to operate both in grid-connected and in islanded mode.

Local DC grids provide flexibility in system design and component integration. They can be designed to suit specific applications, offering adaptability to various types of loads and

[295] ENTSO-E Vision: A Power System for a Carbon Neutral Europe (entsoe.eu)
[296] Sandia National Laboratories (2020) Introduction to microgrids

distributed energy resources, potentially further deferring the need for investments in grid expansion or reinforcement.

Lack of public grid connection capacity: This solution with local grids can reduce the need for grid extension/reinforcement by implementing local options (energy generation, storage, sharing) to cover the electricity demand of e.g. an energy community or commercial/industrial cluster. DC grids can contribute to increased reliability and lower energy network losses compared to AC distribution/transmission networks. This localized solution enhances energy efficiency and reduces strain on the public network.

Congestion management: Microgrids offer flexibility in managing energy resources, allowing for dynamic adjustments in response to changes in demand or supply conditions. This flexibility can contribute to better load balancing and congestion management by managing local demand and storage, thereby reducing strain on the main grid. Peak demand can be avoided by using microgrids that integrate storage assets.

The IEA points out[297] that while emerging technologies like storage and the establishment of microgrids offer alternatives to conventional infrastructure expansion in specific scenarios, it is imperative to acknowledge the ongoing necessity for new infrastructure, such as poles and wires. Microgrids, as well as storage, **ultimately serve as valuable complements to public grids' development, rather than outright replacements.**

6.7.3. Example(s) of application

While various Member States have implemented microgrids to test the solution (with both residential and commercial units involved), such as the Netherlands, Germany, and Greece, legal and regulatory barriers hinder the accelerated development of these. The EU law lacks a clear legal definition and regulation of microgrids[298], including the identification of their types, their technical features, their ownership and operation structures.

Two potential areas for DC-based applications are data centres and EV charging stations[299]. The advantages in both cases stem from the fact that most **decentralized generators produce DC power**, and in this case interacting with a DC grid is more efficient than carrying out the AC/DC conversion.

- **Data centres** are crucial for storing vast amounts of information, and as their importance grows, so does their power demand. Since most of the equipment in data centres runs on DC, using AC connections would lead to energy losses and reliability problems because of the necessary conversions. That is why DC and hybrid AC/DC setups are becoming popular[300] in data centres, supported by relevant research.[301]
- Since **EV** batteries inherently operate in DC, charging them in DC-based charging stations proves to be more effective than using a AC based solution. This trend has spurred research[302] and development[303] efforts towards hybrid AC/DC smart microgrids, incorporating EV charging stations for improved energy efficiency.

[297] Electricity Grids and Secure Energy Transitions – Analysis - IEA
[298] Microgrids and EU laq: Three Microgrids models to solve one regulatory puzzle
[299] A Review on the Driving Forces, Challenges, and Applications of AC/DC Hybrid Smart Microgrids
[300] Microgrids Can Boost Power Options, Resiliency for Data Centers
[301] DC microgrids in buildings and data centers | IEEE Conference Publication
[302] Evaluation of Distributed Generation and Electric Vehicles Hosting Capacity in Islanded DC Grids Considering EV Uncertainty
[303] Fraunhoger IISB DC Grids

6.7.4. Costs of the solution

The CAPEX and OPEX figures of microgrids depend on their configuration and size. We did not furthermore identify literature estimating the share of the overall costs from microgrids which related to their contributions to addressing the network challenges.

6.7.5. Benefits of the solution

- Microgrids offer **continuous power supply during main grid failures**, ensuring resilience and reliability in power outages.
- **Infrastructure cost savings** can be significant when considering the costs of small, local grid investments versus expanding a distribution network to remote areas. Coupled with renewable energy sources, they are a cost- effective decarbonisation solution too.
- Microgrids stand out as highly appealing solutions for **enhancing power distribution efficiency** and minimizing power losses in transmission lines. This is achieved by connecting distributed generation sources, energy storage systems and loads within the same grid.[304]
- Leveraging DC grids for renewable energy sources and storage systems, such as solar panels, battery energy storage systems, fuel cells, and EVs enhances efficiency by avoiding the need for multiple DC/AC and AC/DC conversions, thereby **optimizing the deployment of DC power generated by these systems**. Additionally, DC connections can **bolster the power quality of weaker grids** by acting as a protective "firewall" that prevents the spread of disturbances.[305]

6.7.6. Transaction costs

Microgrids are localised power systems comprised of interconnected loads that, if needed, can operate independently of the main electricity grid, and can offer various services to system operators. When considering transaction costs for the microgrid solution, 4 groups of transactions appear relevant:

1. Grid connection and access
2. Dispatch and control – for the provision of flexibility services to TSO/DSO
3. Accounting and billing – for the settlement of energy exchanges between the microgrid and the public grid
4. Independent management contract with microgrid operator (optional transaction)

The transactions (the concerned parties, the costs and complexity) all differ based on the configuration and ownership/management of the microgrid. A microgrid can, for example, be managed by the DSO, a concerned energy community or a third party (service provider). The ownership structure greatly affects the transaction costs. Currently, the EU regulatory **landscape favours DSO microgrid-owned models**[306] and this seems to be the most cost-efficient ownership structure from a system needs perspective. For this reason we find the interactions between the microgrid and the public grid, and the related transaction costs, most relevant for this study. In cases where the DSO becomes responsible for local balancing, microgrids can also serve as local optimisation asset during islanded operation.

[304] Hybrid ac/dc microgrids—Part I: Review and classification of topologies
[305] A Review on the Driving Forces, Challenges, and Applications of AC/DC Hybrid Smart Microgrids
[306] Microgrids and EU law: Three Microgrid models to solve one regulatory puzzle

Transactions involved in microgrid development are all governed by long-term contracts, with **grid connection and access** being the only one-off transaction. Uncertainty (e.g. about future microgrid use, needs, and costs) and unclear contractual agreements between market actors also influences transaction costs, given incomplete regulation on interactions between consumers and aggregators.[307] The immaturity of microgrid markets and the unique features of each grid are significant factors in defining transaction costs. These factors together with limited regulation lead to medium information asymmetry between the stakeholders. Because of this, and due to difficulties with the interaction between stakeholders regarding energy flows[308] we assume medium S&I and B&D costs for grid connections for microgrids despite it being a well regulated transaction.

The DSO plays a central role in **dispatching and monitoring control** of the electricity connected to the microgrid, and in supporting and managing consumption, and generating real-time metering data. When inaccurate assumptions are used or operational data is missing (due to privacy and security concerns) there might be a medium information asymmetry between parties, which can be higher if the concerned consumers do not understand the monitoring and control methods behind parameters such as voltage, frequency, etc. Cutting edge data analytics carried out by the DSO or the FSP is key in decision-making and raises transaction costs. Market functionality is dependent on technologies needed for dispatching and is varying, especially when considering specialised control equipment that cannot be deployed in other uses[309], or the number of available aggregators/FSPs in some geographies. In the case of islanded operation, an eventual disconnection of the microgrid from the DSO grid can distort power quality and reliability, the costs of which must be taken into account. This results in lengthy agreements on the criteria and methods for islanding, and calls for stringent enforcement - thus medium S&I and B&D costs. P&E costs could be rather high considering that microgrids are a novel solution with limited learnings of actual impacts, and it may be difficult to set penalties.

Accounting and billing should fall under high regulation regarding interactions between the microgrid and the public grid, once the agreements are made. The market functionality for billing software here varies by country. S&I and B&D costs are low, as DSOs have well-run processes for data processing and exchange. These costs can rise higher in non-DSO operated models. Given existing privacy and cybersecurity concerns, P&E costs are medium, due to the need for continuous attention to confidentiality, availability and accountability of data.[310]

As an optional transaction, and as alternative to the standard DSO ownership model[311], an **independent microgrid operator** could be contracted for grid management based on a long-term contract, who would fulfil the role of the DSO. This separate operator would then be responsible for controlling the energy exchanges and providing flexibility services to the DSO, based on their continuous interaction. A model like this would come with high additional transaction costs between this controller/authority and the other parties, especially the DSO, which would all be high compared to a DSO ownership. This is due to

[307] A review of socio-technical barriers to Smart Microgrid development
[308] A review of socio-technical barriers to Smart Microgrid development
[309] A review of socio-technical barriers to Smart Microgrid development
[310] A review of socio-technical barriers to Smart Microgrid development
[311] Where the DSO owns and operates the microgrid, or appoints a specific, related DSO for the grid.Current regulation favours this model (see earlier).

more active participation needed from the microgrid's consumers and due to the need for smooth information transfer between parties despite high initial information asymmetry.

ALPGRIDS project: microgrids in the Alpine region

The ALPGRIDS project was implemented between 2019 and 2022, aiming to develop and replicate microgrids in alpine regions of 5 EU Member States (Austria, Germany, France, Italy and Slovenia).[312]

The project fostered the implementation or expansion of these microgrids, including real-word, large scale applications such as the La Smart Polygeneration Microgrid (SPM) in the campus of the Genova University,[313] which integrates equipment through not only an electrical network but also heating and cooling networks. ALPGRIDS also produced a policy package (also in the language of the Member States of the project partners), identifying barriers and providing recommendations to advance microgrids in the regions, and a template to introduce measures in local energy plans. The program also developed a replication package.

Most of the measures developed by the ALPGRIDs project (listed below) tackle the S&I transaction costs involved with setting up and developing a microgrid.

ALPGRIDS proposed measures to be integrated into local energy plans[314]

COUNTRY	No. of measures	MEASURES IN BRIEF
France	6	1: Launch a first collective self-consumption project 2: Procedures with DSO's IT tool to be simplified and secured 3: Support the emergence of energy communities 4: Become shareholder of local initiatives 5: An Energy point of contact trained to CSC schemes 6: Linking initiatives together
Austria	4	1: Raising awareness for joint consumption of renewable energy through PR promotion and development measures 2: Funding of start-up costs (legal, technical, economic consulting services) for the implementation of local and regional energy communities or direct line systems 3: Funding of start-up costs (production and storage facilities for renewable energy sources) for the implementation of local and regional energy communities or direct line systems 4: Implementation of a regional renewable energy community within the municipality of Weiz with different stakeholders
Germany	5	1: Tenants and neighborhood energy communities 2: Continuous data assessment and adaptation of the energy use plan 3: Optimized development of the charging infrastructure for electrically powered vehicles 4: Making biogas use more flexible 5: Development of wind power use
Italy	11	1: General Action introduced in Genoa SECAP in supporting LECs development 2: Residential and Civil: Promotion of self-consumption schemes, particularly for condominiums, and use of heat pumps supplied by PV systems 3: Industry: Development of local energy communities, particularly in case of high energy demand 4: Industry: Development of local energy communities, particularly in case of high energy demand 5: Behavioral measures for citizens: Promotion and support the self-production and storage of electricity (prosumer) in a context of end-user's empowerment for a rational use of energy 6: Promotion of the use of energy from photovoltaic systems in private sectors 7: Promotion and development of Renewable Energy Communities 8: Renewable Energy Communities Pilot Project - Alpgrids Project 9: Investments for the production of energy from municipal photovoltaic systems 10: Strengthening of the Energy Desk (Sportello Energia) 11: Creation of the "One Stop Shop"
Slovenia	3	1: Promoting the self-sufficiency of residential and commercial buildings 2: Promoting the establishment of electrical micro-networks 3: Energy and RES communities

6.7.7. Other barriers

Microgrid deployment still faces a diverse range of barriers spanning institutional, regulatory, financial, social, and technical issues, complicating efforts to integrate these systems into existing electricity infrastructure. One of the main challenges lies in the **unclear legal definition of microgrids and their associated liabilities and responsibilities**, creating uncertainties that hinder adoption and investment. Technical

[312] Interreg Alpine Space. ALPGRIDS - Increasing RES uptake through Microgrids in the Alps
[313] Università di Genova. La Smart Polygeneration Microgrid (SPM)
[314] ALPGRIDS (2022) Microgrid Policy Package

and economic challenges related to interconnection with distribution grids and island mode rules further complicates microgrid deployment strategies.

Institutional barriers, including entrenched lock-in into traditional systems[315] and difficulties in stakeholders' coordination, remain significant barriers too. This is inherent to decentralised systems with new ownership and operation models. Legal and regulatory hurdles, such as varying regulations across countries and unclear contractual and financial agreements[316], add further layers of complexity. The regulatory approach towards microgrids is subject to the discretion of individual Member States in granting energy communities the right to 'manage part of the distribution network'.[317] **Financial constraints,** including **high investment risks**[318] and limited resources, impede the scalability and viability of microgrid projects.

Regulatory barriers arise when looking at microgrid **ownership and operation**: a 2023 paper on microgrids and EU law[319] points out that each microgrid differs in its ownership structure, purpose, and technical setup, which results in difficulties integrating microgrids in the EU legal framework. There is no EU regulation specifically tailored to microgrids, which makes their position unclear under the unbundling regime, especially if ownership and operation are carried out by the same party. It also states that **the current landscape favours DSO microgrid ownership models** which mitigate challenges associated with legal definitions and ownership responsibilities. However, advancements in technology and evolving business models are driving interest in more demanding third-party and hybrid ownership models[320]. These models can offer greater flexibility but also bring additional costs and complexities, as described under the transaction costs.

Data ownership and management, if organised in a secure and transparent manner, can bring benefits and optimised load control, energy management and event detection in microgrids. However, this calls for innovative, data-driven business strategies for stakeholders involved. Aggregators, consumers/prosumers, and system operators are sometimes reluctant to deploy the most modern technologies as they have not yet been widely deployed and still entail some first user risks[321]. Cybersecurity risks prevail regarding handling, storing and sharing data.

Various **technological challenges** have also been studied and identified in a 2022 paper, mainly related to the fact that microgrids require sophisticated control systems to operate and interact with the main grid securely. With regards to islanded more, islanding detection techniques (methods used to identify when a distributed DER or microgrid continues to operate in an islanded mode) could also be improved in terms of their speed, power quality and costs.[322] Smart meters and other digital energy management tools (e.g. AC and DC power supplies) are a technological prerequisite for microgrid deployment.

Besides the economic and technical barriers, addressing **social acceptance issues** is still crucial for the further progress of microgrid deployment, necessitating targeted education

[315] A review of socio-technical barriers to Smart Microgrid development
[316] Between prosumers, suppliers and aggregators. A review of socio-technical barriers to Smart Microgrid development
[317] Microgrids and EU law: Three Microgrid models to solve one regulatory puzzle
[318] Literature refers to the absence of a clear cost-benefit-sharing mechanisms and a lack of global technical standards for microgrid technologies and equipment
[319] Microgrids and EU law: Three Microgrid models to solve one regulatory puzzle - ScienceDirect
[320] With different motivations, and different level of involvement from prosumers. Additional models identified in Microgrids and EU law: Three Microgrid models to solve one regulatory puzzle
[321] A review of socio-technical barriers to Smart Microgrid development
[322] A review of socio-technical barriers to Smart Microgrid development

and engagement initiatives to build trust and garner support from local communities. On the supply side, there is a preferential lock-in effect observed into traditional, centralised electricity systems: utilities are concerned that e.g. if more microgrid users opt for net metering while connected to the main grid, and not contributing to network costs then they might not be able to afford financing grid upgrades. [323]Market dynamics, including the lack of incentives for prosumers to invest in microgrid solutions (e.g. the lack of dynamic pricing and some external benefits not being fully reflected in electricity prices) further hinder market participation and innovation.

Table 19: Barriers to the deployment of microgrids

Barrier type	
Regulatory	• Regulation can differ per country, no EU regulation tailored specifically to microgrids • Unclear contractual agreements between market actors and microgrid users • Privacy and cybersecurity concerns • Current EU regulation not accommodating all different ownership models
Financial	• High risks for investment and a lack of financial resources • Lack of incentives for prosumers to invest microgrid solutions • Decentralised systems an inclusion of RES endangers the interests of traditional generators and market players
Social	• Social acceptance of wider communities and local residents, including lack of awareness on the market benefits
Technical	• Complicated design features of control systems, mainly because of islanded mode • Slow smart device deployment
Organisational	• Lock-in into traditional systems and inertia to change the current power system structure • Coordination complexity regarding the management of the network operation between multiple network users and the operator

[323] Microgrids: A review, outstanding issues and future trends

Trinomics B.V.
Mauritsweg 44
3012 JV Rotterdam
The Netherlands

T +31 (0) 10 3414 592
www.trinomics.eu

KvK n°: 56028016
VAT n°: NL8519.48.662.B01