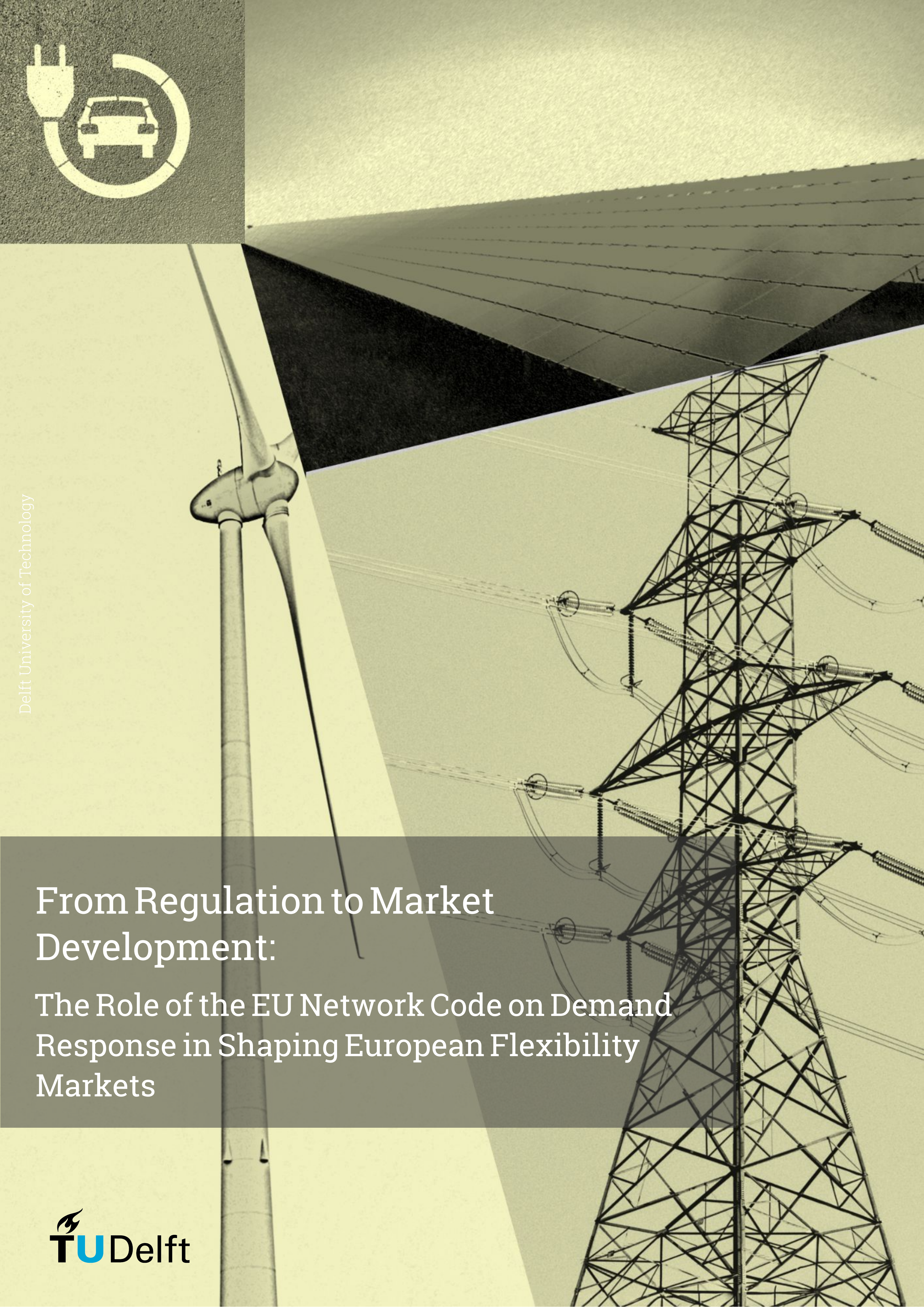

Delft University of Technology

From Regulation to Market Development:

The Role of the EU Network Code on Demand Response in Shaping European Flexibility Markets

TU Delft

From Regulation to Market Development:

The Role of the EU Network Code on Demand Response in Shaping European Flexibility Markets

by

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TU Delft

Preface

Reflecting on the past two years, I would not say that the EPA programme completely changed the way I think. Systems thinking is one of the core ideas of EPA, but I believe that this way of thinking is also something people gradually develop through work and collaboration. Even as an engineer with a technical background, it is difficult to solve real-world problems without understanding the wider system and the people involved. What EPA did for me was to make this perspective much more explicit. At the same time, the programme gave me a more diverse toolbox. Before coming to Delft, for example, I had never formally learned Python or many of the modelling methods used during the programme. The intensive courses, frequent teamwork, and high expectations helped me improve not only my analytical skills, but also my ability to work with different people and approach unfamiliar problems. For my own professional background, EPA also gave me a much broader understanding of the energy transition. I learned to look at energy systems not only through engineering, but also through regulation, markets, actors, and policy. The past two years have also given me a much better understanding of the energy transition taking place in the Netherlands and across Europe.

This thesis brought many of these perspectives together. Before working on flexibility, my understanding of power systems was mainly physical. When I thought about grid congestion, my first response as an electrical engineer was naturally grid reinforcement. However, when space, time, and economic constraints are considered, flexibility can provide another way of using the existing grid more intelligently. This has changed how I think about future electrical system design. Whether flexibility comes from renewable generation or from demand-side resources, assets increasingly need to interact with the grid rather than simply connect to it. Data centres are one example. Their rapidly increasing electricity demand can make grid connection difficult, but if part of their demand can also become flexible, this may both support their integration and help the grid manage congestion more securely.

Studying the forthcoming Network Code on Demand Response (NCDR) also gave me the opportunity to understand how European regulation develops around such changes. The NCDR needs to provide common rules while recognising that Member States have different electricity systems, markets, and institutional arrangements. I found this balance between European harmonisation and national flexibility particularly interesting. The thesis also introduced me more deeply to electricity markets. I increasingly came to see the market and the physical power system as two parallel systems that continuously constrain each other. Balancing markets are needed because the physical system must maintain the balance between supply and demand at every moment. At the same time, physical congestion can now create a need for local flexibility markets in which flexibility is traded to solve network problems. Understanding this interaction between the market and the physical system has been one of the most valuable parts of this research for me.

I am very grateful to my thesis committee for their support throughout this process. I would especially like to thank *Özge* for helping me organise my thoughts and continuously refine the direction of the research. Our regular meetings were particularly important after some delays at the beginning of the thesis and helped me keep the work on schedule. I would also like to thank *Linda* for her support when I changed the thesis direction after the kick-off meeting. She helped me quickly identify a new research direction and was always encouraging. Her feedback was direct and focused on the key areas for improvement.

Finally, I would like to thank the friends I met through EPA and all the faculty and programme staff involved in the programme. The knowledge and methods I learned are important, but I also feel that one of the most lasting parts of EPA will be the friendships and experiences that came with it. Because the programme connects engineering with society, conversations often went far beyond technical problems and included questions about policy, people, and the society in which these systems operate. I am also grateful for the care that was clearly put into the design of the EPA curriculum. Courses from different quarters often connected with each other in ways that only became clear later, and the coordination

between courses made an intensive programme feel demanding but manageable. Looking back, I appreciate not only what I learned during EPA, but also the people, perspectives, and experiences that came with it.

Yao Wang
Rotterdam, August 2026

Summary

Electrification and the growth of variable renewable energy are increasing the need for flexibility in European electricity systems. Grid reinforcement remains essential, but it cannot address all network constraints alone. Demand-side flexibility is therefore increasingly seen as a complementary solution. One way to use this flexibility is through local flexibility markets. These are market-based arrangements in which system operators procure local services, such as congestion management and voltage control, from distributed resources.

The development of local flexibility markets in Europe is uneven. Some countries have operational markets, while others still rely on pilots or have limited activity. In response, the European Union is preparing the Network Code on Demand Response (NCDR). The NCDR aims to remove barriers to the participation of demand-side flexibility in electricity markets. It also introduces common rules for market-based procurement of local services and for coordination between system operators.

The NCDR will enter a diverse European market landscape. Member States differ in market maturity, institutional design, and regulatory starting points. Existing research has described flexibility market designs and barriers in Europe. However, there is still limited understanding of how current local flexibility market arrangements align with the forthcoming NCDR and what this alignment reveals about implications of the code. This thesis addresses this gap by answering the following research question:

> ***What does the alignment of current national flexibility market arrangements with the NCDR reveal about its implications for flexibility market development?***

Since the NCDR has not yet entered into force, this thesis uses a qualitative research design. The research combines regulatory analysis, assessment framework development, and comparative case assessment. First, the draft NCDR was analysed article by article. Provisions relevant to flexibility markets were recorded in a requirement extraction table. The extracted requirements were organised into five main categories and fifteen subcategories.

Second, selected requirements were translated into an assessment framework. The framework contains twenty-two indicators across four assessment subcategories, including procurement mechanism, market coordination, baseline methodology, and TSO–DSO coordination. These subcategories were selected because they are central to local flexibility market development and can be assessed using available evidence.

Third, the framework was applied to France and the Netherlands. These two countries were selected through a most-different case design. France represents a DSO-led tender model, mainly organised through Enedis local flexibility tenders. The Netherlands represents a market-embedded platform model, in which GOPACS links grid operators' congestion management needs to existing intraday trading platforms. The assessment was based mainly on document analysis. Semi-structured expert interviews were used to fill evidence gap, validate interpretations and add implementation context.

The case assessment shows that both France and the Netherlands have formal and operational arrangements for market-based procurement of local services, but they show different readiness profiles. France is strong in formal procurement design and baseline validation, mainly through Enedis' structured tender process and contractual baseline rules. Its main gaps relate to coordination. The Netherlands is strong in market coordination and system operator coordination, mainly through national congestion management rules and the GOPACS platform. Its main gap is baseline methodology, because the prognosis-based reference used in practice has not yet been formalised as a national methodology that fully meets the NCDR quality principles.

These findings lead to three main implications for flexibility market development. First, the NCDR mainly harmonises common market functions, processes, and coordination requirements rather than imposing one common market architecture. Second, the same requirements lead to different implementation pathways depending on existing national arrangements. For mature markets such as France and the Netherlands, implementation mainly involves the formalisation, integration, and completion of existing arrangements. Third, regulatory alignment has clear limits. The NCDR can directly address many regulatory and technical gaps and partly reduce operational barriers, but it cannot by itself ensure market liquidity and predictable revenues.

Overall, the findings suggest that the NCDR can provide a common regulatory foundation for flexibility market development while allowing different national market arrangements to remain in place. Its implications depend on both the national starting point and the type of barrier involved. Effective market development will require not only NCDR alignment, but also national implementation and complementary action where economic and operational barriers remain. The thesis also contributes a structured assessment framework linking NCDR requirements to observable features of national flexibility market arrangements.

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Nomenclature

Abbreviations

Abbreviation	Definition
ACER	European Union Agency for the Cooperation of Energy Regulators
ACM	Authority for Consumers and Markets
aFRR	Automatic Frequency Restoration Reserve
BM	Baseline Methodology
BRP	Balance Responsible Party
CAPEX	Capital Expenditure
CEER	Council of European Energy Regulators
CRE	Commission de régulation de l'énergie
CSP	Congestion Service Provider
CU	Controllable Unit
DERMS	Distributed Energy Resource Management System
DSO	Distribution System Operator
DSF	Demand-Side Flexibility
EU	European Union
EV	Electric Vehicle
FCR	Frequency Containment Reserve
FIS	Flexibility Information System
FSP	Flexibility Service Provider
GOPACS	Grid Operators Platform for Congestion Solutions
ICT	Information and Communication Technology
LFM	Local Flexibility Market
MA-RE	Market Rules for Balance Responsible Entities and System Services
MC	Market Coordination
mFRR	Manual Frequency Restoration Reserve
NCDR	Network Code on Demand Response
NIO	Network Information Object
OPEX	Operational Expenditure
ORA-MP	Offre de Raccordement Alternative avec Modulation de Puissance
PM	Procurement Mechanism
PV	Photovoltaic
ReFlex	Raccordement Express Flexible
RES	Renewable Energy Sources
ROP	Reserve Other Purposes
RTE	Réseau de Transport d'Électricité
SOC	System Operator Coordination
SP	Service Provider
SPG	Service Providing Group
SPU	Service Providing Unit
TDTR	Tijdelijk Deelbare Transportrechten
TSO	Transmission System Operator
TURPE	Tarif d'Utilisation des Réseaux Publics d'Électricité
USEF	Universal Smart Energy Framework
VVTR	Volledig Variabele Transportrechten

1

Introduction

1.1. Problem context

The rise of electrification and the rapid expansion of variable renewable energy are increasing the need for flexibility in electricity systems. At the same time, the share of controllable generation capacity is declining, while electricity demand is expected to grow substantially over the coming decade (International Energy Agency [IEA], 2025; van Dijk and Treurniet, 2026). These developments place increasing pressure on electricity networks, especially as ageing grid infrastructure, spatial constraints, and permitting delays make grid reinforcement alone insufficient to address all emerging system needs. As a result, electricity networks are gradually shifting from traditionally passive operation toward more active management. Demand-side flexibility (DSF) refers to changes in planned electricity consumption, generation, or storage use in response to price signals or instructions, by residential, commercial, or industrial customers, individually or through aggregation (LCP Delta and smartEn, 2026). In this context, DSF is increasingly seen as a promising option to support system operation, alleviate local constraints, and defer or reduce infrastructure investment needs (Esmat and Usaola, 2016). Market-based procurement is one important way to access DSF transparently and cost-efficiently. It allows system operators to procure flexibility services such as congestion management, voltage control, and network investment deferral. A local flexibility market (LFM) is a market-based arrangement for buying and selling flexibility for local services, usually at the distribution level or within a limited geographical area (Chondrogiannis et al., 2022; Ramos et al., 2016).

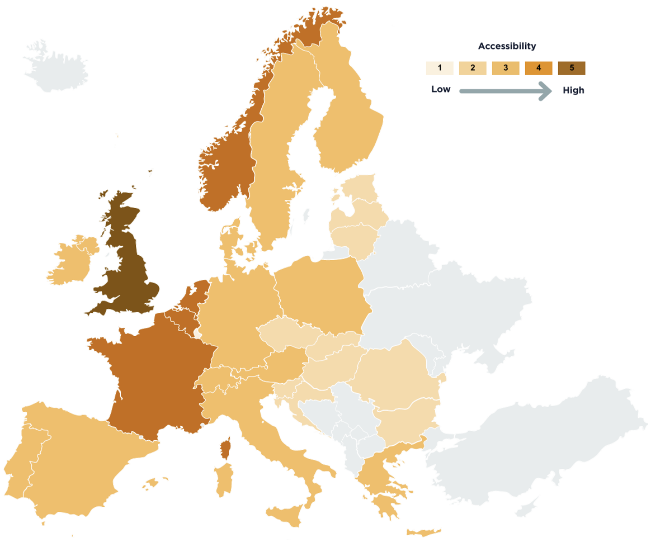

Figure 1.1: 2024 Demand-side flexibility accessibility level across European countries. (LCP Delta and smartEn, 2025)

Across Europe, DSF and LFMs are developing rapidly. However, practical deployment remains uneven and limited across countries (LCP Delta and smartEn, 2026), as shown in Figure 1.1. At the EU level, regulatory initiatives have increasingly aimed to support market-based flexibility procurement. Article 32 of the Electricity Directive (EU) 2019/944 provides an important legal foundation by requiring Distribution System Operators (DSOs) to procure flexibility services through transparent, non-discriminatory, and market-based procedures, unless regulatory derogations apply. Building on this direction, the Network Code on Demand Response (NCDR) is being developed as a harmonised EU regulatory framework, with national implementation expected in the coming years (Touhey, 2025). The NCDR aims to remove unnecessary barriers to the participation of DSF in electricity markets, and to establish common European principles and requirements for market-based procurement of local services, and coordination between system operators (ACER, 2025a, 2025b).

However, the NCDR will be introduced into a highly diverse European market landscape. Member States differ in the maturity of their flexibility markets, grid conditions, digitalisation levels, regulations, and existing coordination mechanisms. Consequently, implementing common NCDR requirements may require different adaptations across national contexts. Therefore, it is important to assess how current flexibility market arrangements align with the proposed NCDR requirements, and what this implies for the future development and harmonisation of European local flexibility markets.

1.2. Academic relevance and research gap

The challenges outlined above have attracted growing scholarly attention. Over the past decade, research has examined how local flexibility markets are designed, how they operate, and what limits their further development. Comparative European studies have mapped market designs and operational maturity across countries. These studies show that flexibility markets remain unevenly developed and face barriers such as regulatory fragmentation, the lack of standardised flexibility products, and insufficient communication and automation infrastructure (Jo, 2025; Scrocca et al., 2026). Other research focuses on specific aspects of market development, including baseline methodologies, prequalification procedures, and TSO–DSO coordination (Shi and Xu, 2024; Tsaousoglou et al., 2024; Zipperling et al., 2022). Together, this literature provides an important foundation for understanding the current state of LFMs in Europe.

Despite the growing body of literature, the relationship between existing flexibility market arrangements and the forthcoming NCDR has not yet been systematically examined. To explore this gap, the literature review considered studies related to the main themes addressed by the NCDR, including aggregation, baseline estimation, measurement rules, qualification requirements, flexibility information systems, market-based procurement of local services, network planning, TSO–DSO coordination, and data exchange. These themes were derived from the ACER NCDR webinar overview slides and used to position existing research in relation to the regulatory scope of the code(ACER, 2025b). Table 1.1 maps the reviewed studies across these NCDR-related themes and contextual dimensions. The comparison shows which aspects of flexibility market development are already well covered in the literature and where gaps remain. In particular, it highlights that existing studies often address specific elements of flexibility market design, but rarely assess current market arrangements against the integrated set of requirements introduced by the NCDR.

Two academic gaps can be identified from the comparison. First, comparative studies often analyse flexibility markets through market-design, technical, or institutional lenses. However, these lenses are not directly aligned with the structured requirements introduced by the NCDR. As a result, there is no consistent framework for assessing how prepared current national arrangements are for the regulatory transition created by the code. Second, existing studies identify barriers such as regulatory fragmentation, product heterogeneity, and coordination challenges, but it remains unclear which of these barriers the NCDR may address and which may persist after implementation. Since harmonisation is a central objective of the code, its implications are likely to differ across Member States with different market and regulatory starting points. This variation has not yet been systematically analysed.

This thesis contributes to the literature by analysing how the NCDR relates to the ongoing development of flexibility markets across Europe. It provides a comparative perspective on potential implementation gaps, challenges, and the implications of EU-level harmonisation for national flexibility market frameworks. In doing so, it helps bridge the gap between existing studies on current flexibility market barriers and the still uncertain regulatory effects of the upcoming NCDR.

Table 1.1: Mapping of reviewed literature against NCDR-related themes and contextual focus.

Reference	Agg.	Qual.	Mkt.	Plan	Coord.	EU	Barr.	NCDR
Khodabakhsh et al., 2025	-	-	X	-	-	-	-	-
Spiliotis et al., 2016	-	-	X	X	-	-	-	-
Esmat and Usaola, 2016	-	-	X	-	-	-	-	-
Shekari et al., 2023	X	-	-	-	-	-	-	-
Del Granado et al., 2023	X	-	X	-	X	-	-	-
Rebenaque et al., 2023	-	-	X	-	X	X	X	-
Vigano et al., 2023	-	-	X	-	X	X	X	-
Scrocca et al., 2026	X	X	X	-	X	X	X	-
Jo, 2025	-	-	X	-	X	X	X	-
Nolden et al., 2025	-	-	X	-	-	-	X	-
Jimeno et al., 2025	-	-	X	-	-	X	X	-
Rodrigues et al., 2024	-	-	X	-	-	X	-	-
Cabot and Villavicencio, 2024	X	-	X	-	-	X	X	-
Viganò et al., 2024	X	-	X	-	X	X	X	-
Mousavi et al., 2023	-	-	X	-	X	X	-	-
Akkouch et al., 2024	-	-	X	-	X	X	X	-
Shi and Xu, 2024	X	-	-	-	-	-	-	-
Öztürk et al., 2022	X	-	-	-	-	-	-	-
Rodríguez-García et al., 2018	-	X	-	-	-	-	X	-
Baltputnis et al., 2020	-	X	-	-	X	-	X	-
Zipperling et al., 2022	-	X	-	-	-	-	X	-
Messias et al., 2026	-	-	X	X	-	-	-	X
Vroon et al., 2025	-	-	-	X	-	-	-	-
Tsaousoglou et al., 2024	-	-	X	-	X	-	-	-
Couto et al., 2025	-	-	-	-	X	-	-	-

Agg. = Baseline/Aggregation/Measurement; Qual. = Qualification/FIS; Mkt. = Market-based procurement & congestion/voltage management; Plan = Long-term planning & flexibility integration; Coord. = TSO–DSO coordination/data exchange; EU = Comparative European focus; Barr. = Explicit discussion of barriers or implementation challenges; NCDR/Harm. = Explicit reference to NCDR or EU harmonisation.

1.3. Research objectives and questions

Building on the problem context and research gap discussed above, this thesis examines the potential role of the forthcoming EU Network Code on Demand Response (NCDR) in the development of flexibility markets in Europe. Since the NCDR has not yet come into force, the thesis does not evaluate its actual implementation effects. Instead, it assesses how current national flexibility market arrangements align with selected NCDR requirements and what this alignment reveals about the code's possible implications on market development. Given that Member States differ in market maturity, institutional design, and regulatory starting points, this role is expected to vary across national contexts.

The main research question is formulated as follows:

"What does the alignment of current national flexibility market arrangements with the NCDR reveal about its implications for flexibility market development?"

To answer this main research question, the thesis pursues two interconnected research objectives. The first objective is to develop an NCDR-aligned assessment framework. This requires systematically identifying the requirements introduced by the NCDR and translating them into analytical categories, indicators, and assessment criteria. The second objective is to apply this framework to selected European flexibility market cases. This makes it possible to assess current market arrangements, identify implementation gaps, and discuss the implications of NCDR harmonisation for different national contexts.

The research is structured around three subquestions. The first two subquestions focus on framework development:

SQ1. What requirements related to flexibility markets are introduced by the NCDR?

This sub-question identifies the NCDR requirements that are relevant to flexibility market development. Through structured document analysis of the NCDR draft, ACER materials, and related regulatory documents, relevant requirements will be extracted, identified and organised into categories and subcategories.

SQ2. How can these requirements be translated into a structured assessment framework?

This subquestion translates the extracted NCDR requirements into a framework for assessing existing flexibility market arrangements. Using the selected categories and subcategories, it develops indicators and assessment questions. Thus, it links the regulatory text of the NCDR with observable features of national flexibility markets.

The third subquestions applies the framework to selected country cases:

SQ3. How do selected national flexibility market arrangements align with the NCDR requirements?

This subquestion applies the assessment framework to the French and Dutch cases. It examines how current flexibility market arrangements are organised in relation to the selected NCDR-related requirements, rather than providing a general description of each national market. The analysis identifies areas of alignment and misalignment across procurement mechanism, market coordination, baseline methodology, and TSO–DSO coordination.

The subquestion also interprets the assessment results in relation to market development barriers. This involves examining whether the identified gaps are likely to be fully addressed by the NCDR, partially addressed, or remain largely beyond its direct reach. In this way, the case analysis connects regulatory alignment to the broader role of the NCDR in shaping European flexibility markets.

1.4. Research design

Research design refers to the overall plan that links the research questions, inquiry strategy, and specific research methods (Creswell, 2009). This thesis examines how the forthcoming NCDR may help shape the development of flexibility markets in Europe. Since the NCDR has not yet entered into force, its impact cannot be assessed through observed implementation outcomes. Therefore, this study employs a qualitative research design based on regulatory analysis, framework development, comparative case assessment, and interview analysis and validation.

The research is organised around three subquestions. SQ1 and SQ2 focus on developing the assessment framework. SQ1 identifies the NCDR requirements relevant to flexibility market development. This is achieved through structured desk research and a detailed, article-by-article analysis of the draft NCDR Annex 1. Relevant requirements are recorded in a requirement extraction table, which includes the article reference, requirement summary, responsible actors, and the related category. ACER explanatory materials, webinar documentation, EU regulatory documents, and academic literature are used to support the interpretation of the regulatory text. The detailed requirement extraction process is explained in Chapter 3.

SQ2 translates the extracted NCDR requirements into an assessment framework. This step involves selecting assessment subcategories, defining indicators, developing assessment questions, and specifying scoring criteria. The goal is to connect the regulatory requirements of the NCDR with observable features of national flexibility market arrangements. The framework development process, including the rationale for choosing the four assessment subcategories, is also explained in Chapter 3.

SQ3 applies the assessment framework to selected country cases and interprets the results in relation to market development. A comparative case study approach is employed for the assessment. Case studies are well-suited for examining contemporary phenomena within their real-world contexts, especially when the boundaries between the phenomenon and its context are not clearly defined (Crowe et al., 2011). The use of multiple cases allows the research to identify similarities and differences across national arrangements while preserving case-specific context (Adams et al., 2022). The detailed case study design, case selection logic, document collection process, scoring approach, and interview design strategy are presented in Chapter 4. For each case, publicly available documents are collected and reviewed. These documents are organised according to the NCDR-aligned assessment framework. Semi-structured interviews serve as a supplementary method for evaluation, validation, and interpretation. Based on document analysis and interview evidence, each indicator is scored according to the available evidence, and the rationale behind each score is documented. The country assessments and the cross-case comparison are presented in Chapter 5. The Implications of the role of the NCDR are discussed in Chapter 6, by linking alignment gaps with barriers to market development.

The entire research flow is illustrated in Figure 1.2. This design enables the thesis to progress from extracting regulatory requirements to conducting empirical case assessments, and ultimately to a broader interpretation of how the NCDR may influence the development of flexibility markets across various European contexts.

1.5. EPA relevance

This thesis was conducted as part of the MSc Engineering and Policy Analysis (EPA) programme at TU Delft. The topic aligns with EPA because it addresses a societal challenge in the energy transition: how electricity systems can make better use of demand-side flexibility through market-based arrangements while maintaining secure and reliable grid operation. The analytical research takes a systems perspective, because this challenge is not only as a technical grid problem. It also depends on regulation, market design, institutional coordination, and the behaviour of different actors.

The forthcoming NCDR introduces common European rules for demand-side flexibility. However, its requirements must be implemented in Member States with different market designs, grid conditions, and institutional responsibilities. This creates policy and decision-making challenges, including the balance between EU-level harmonisation and national adaptation, and between formal regulatory alignment and practical market development. Common European rules can reduce regulatory fragmentation and make participation across Member States easier, but national adaptation remains necessary because grid conditions and market maturity differ across countries.

The thesis also adopts a multi-actor perspective. Local flexibility markets involve TSOs, DSOs, regulators, service providers, and platform operators, placing the issue at the interface between the public and private domains. These actors do not always have the same responsibilities, incentives, or information. For example, system operators may need flexibility to manage grid congestion in specific locations, while market participants may have limited interest if expected revenues are uncertain or too low. Such differences influence how flexibility markets develop and how regulatory requirements are implemented in practice.

This thesis contributes to policy analysis by providing a structured and traceable assessment framework that translates NCDR requirements into observable features of national flexibility market arrangements. The framework supports the systematic analysis and comparison of different national arrangements. Because the NCDR has not yet entered into force and its practical effects remain uncertain, the analysis can help inform decision-makers about possible implementation gaps, different national adjustment needs, and issues that remain beyond regulatory alignment. By comparing contrasting national flexibility market arrangements, the thesis shows how a common EU regulation may lead to different national implementation pathways.

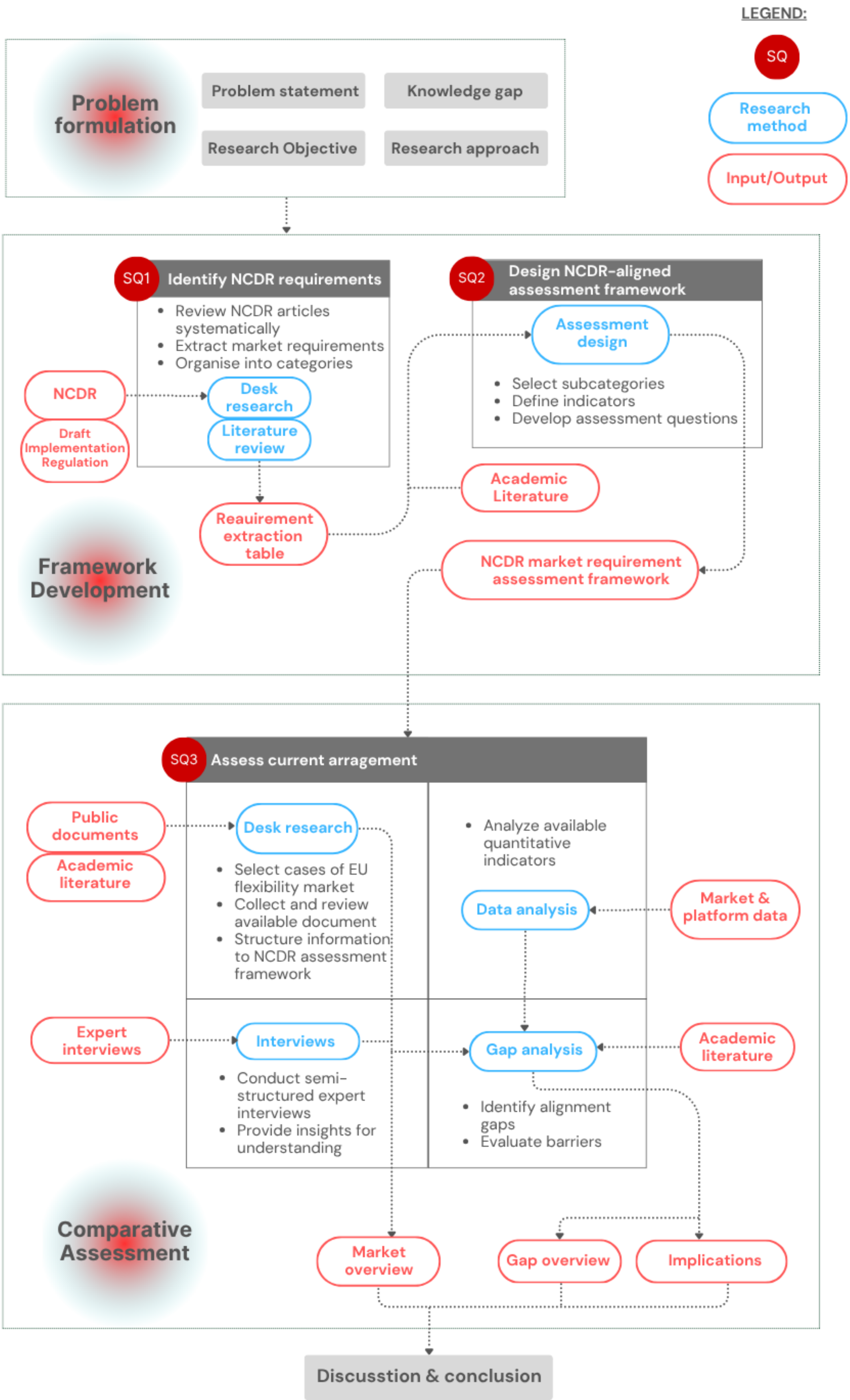

Figure 1.2: Research flow diagram.

1.6. Thesis structure

This thesis is structured into seven chapters. Chapter 1 introduces the research problem, the academic and policy relevance of the study, the research objectives, and the research design. It also presents the main research question and sub-questions.

Chapter 2 provides the background for the study. It introduces demand response, demand-side flexibility, flexibility services, system needs, and local flexibility markets. It then discusses the diversity of flexibility market designs in Europe and the main barriers to market development. Additionally, it presents the Network Code on Demand Response, covering its regulatory background, objectives, scope, and key themes.

Chapter 3 develops the requirements framework used in this thesis. It first extracts relevant NCDR requirements and groups them into five initial categories: product design, pre-qualification, procurement, settlement and activation, and governance. It then explains the selection of four assessment subcategories: procurement mechanism, market coordination, baseline methodology, and TSO–DSO coordination. Finally, it maps these subcategories to the indicators used in the case assessment.

Chapter 4 explains the case study methodology. It presents the case study design, the selection of France and the Netherlands, and the rationale for using a most-different case design. It also describes the document analysis process, the scoring approach, and the role of interviews in validating and refining the assessment.

Chapter 5 presents the case assessment. It first evaluates the French case and then the Dutch case across four subcategories. The chapter then compares the two cases to identify similarities and differences in their alignment with the NCDR-related requirements.

Chapter 6 discusses the implications of the findings. It first identifies the main barriers to market development observed in the two cases. It then examines the scope of NCDR harmonisation, different national implementation pathways, and the limits of regulatory alignment. Based on these findings, the chapter provides practical recommendations for France, the Netherlands, and the further development and implementation of the NCDR. It concludes by discussing the limitations of the study.

Chapter 7 concludes the thesis by answering the sub-questions and the main research question. It brings together the main implications of the findings for flexibility market development and identifies directions for future research.

2

Background

This chapter provides the conceptual and regulatory background for the thesis. It begins by introducing demand-side flexibility and explaining how flexibility can support various system needs. Next, it discusses local flexibility markets as market-based mechanisms for procuring location-specific flexibility services and reviews the diverse market designs currently emerging across Europe. Finally, the chapter presents the NCDR, covering its regulatory background, objectives, scope, and main content areas. This foundation sets the stage for developing the NCDR requirement assessment framework.

2.1. Flexibility and local markets

Grid congestion and the need to unlock demand-side flexibility are central challenges in the energy transition. As renewable energy and electrification increase, congestion is expected to grow not only at transmission level but also in distribution networks. Local flexibility markets offer a market-based way to manage these constraints by allowing system operators to procure flexibility from distributed resources. Rather than replacing grid reinforcement, they can complement network development by making better use of existing system flexibility. For network operators, these markets provide a tool to address local congestion and voltage issues. For flexibility providers, they create an additional revenue opportunity (EPEX SPOT, 2022).

2.1.1. Demand-side flexibility

Demand-side flexibility (DSF) refers to changes in planned electricity consumption, generation, or storage use in response to price signals or instructions, by residential, commercial, or industrial customers, individually or through aggregation (LCP Delta and smartEn, 2026). It can be achieved through explicit mechanisms, such as formal contracts with aggregators, or implicit mechanisms, where consumers respond manually or automatically to time-varying price signals. By utilizing digital tools like smart meters and control systems, the common applications of DSF include shifting electric vehicle charging, rescheduling non-critical industrial processes, and using batteries to store excess renewable energy. It provides a cost-effective way to manage power systems and enhance resilience without disrupting normal consumer activities (International Energy Agency [IEA], 2025).

The value of DSF extends far beyond simple system balancing. It significantly improves electricity system efficiency by reducing reliance on inefficient peaking plants and minimizing the curtailment of renewable energy sources. Additionally, DSF enhances energy security by ensuring resource adequacy during critical periods. Demand flexibility also promotes affordability by enabling consumers to shift usage to lower-cost hours, thereby reducing overall system investment requirements. Finally, it plays a vital role in reducing emissions by aligning electricity demand with periods of high low-carbon generation (International Energy Agency [IEA], 2025).

2.1.2. Flexibility services and system needs

Flexibility can create value for different actors in the electricity system. As shown in Figure 2.1, flexibility transactions involve several actors, including prosumers, aggregators, Balance Responsible Parties (BRPs), Transmission System Operators (TSOs), and Distribution System Operators (DSOs). These participants engage in different stages of the flexibility value chain: flexible resources are typically located at consumer or prosumer sites; aggregators pool and offer these resources; BRPs use flexibility for portfolio optimisation; and system operators procure flexibility to manage balancing or network constraints.

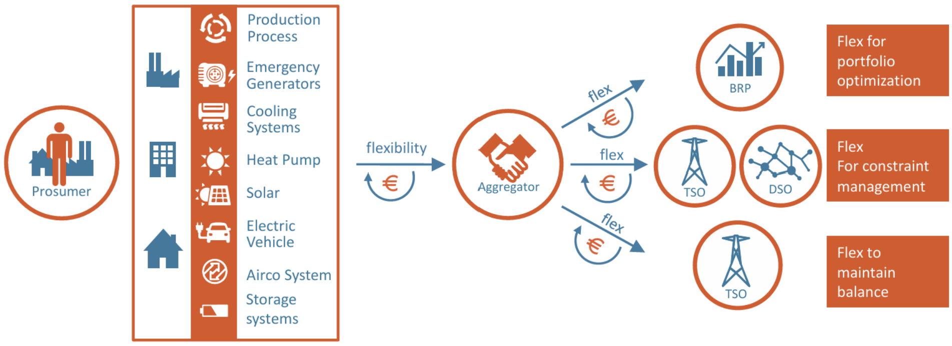

Figure 2.1: Flexibility value chain.(Bontius and Hodemaekers, 2018)

From a grid security perspective, the main use cases for flexibility from distributed generation and consumption are balancing services, congestion management, and voltage control. These services address different system needs. Balancing focuses mainly on maintaining system-wide equilibrium between supply and demand, whereas congestion management and voltage control are more closely related to managing network constraints at specific locations.

- **Balancing service**
  Balancing services use flexibility to maintain the real-time balance between electricity supply and demand. In Europe, the primary goal of balancing is to keep the grid frequency at constant 50 Hz. If generation exceeds demand, the frequency rises; if demand exceeds generation, the frequency falls. These deviations, known as imbalances, can threaten system stability if not corrected.

  BRPs first attempt to maintain balanced portfolios by scheduling expected production, consumption, and trades. If all BRPs fail to keep the grid stable and an overall system imbalance persists, the TSOs will intervene by activating balancing products procured in advance. These services are provided by flexible assets such as batteries, demand response, renewable generation, or other controllable resources. Common balancing products include frequency containment reserves (FCR), automatic frequency restoration reserves (aFRR), and manual frequency restoration reserves (mFRR), which differ in their activation periods (Wampack, 2023).

- **Congestion management**
  Network congestion occurs when electricity flows exceed the local grid's capacity limits, creating thermal, voltage, or stability risks (Wampack, 2023). The problems range from highly localized issues, such as low-voltage feeders serving around 100 households, to broader areas, such as high-voltage transmission stations serving over 10,000 households (Hennig et al., 2023). This can increase operational costs and, in severe cases, threaten system reliability. As grid congestion becomes more frequent, system operators need tools to manage local constraints before they threaten system operation.

  Traditionally, transmission-level congestion has been addressed primarily through redispatch, while distribution networks have relied mainly on grid reinforcement (EPEX SPOT, 2022). However, the increasing integration of renewable generation, electric vehicles, heat pumps, and other distributed resources requires a broader use of flexibility at both transmission and distribution levels. The current typical congestion management mechanisms at the distribution level are generally classified into three primary categories: network access pricing, local flexibility markets, and direct load control. These methods differ based on who controls the load, either DSOs or end-users, and whether the operator is ”offering” access under specific conditions or ”buying back” access rights to alleviate a bottleneck (Hennig et al., 2023).

- **Voltage control**
  Voltage control refers to maintaining voltage levels within acceptable operating limits throughout the electricity network. Voltage issues can occur when local generation or consumption changes the voltage profile of a feeder or network area. For instance, high photovoltaic generation in rural low-voltage grids can cause voltage to exceed the upper limit, while significant consumption from loads such as electric vehicles can lead to voltage drops below the lower limit. If left unmanaged, these voltage deviations can negatively impact power quality, equipment performance, and the secure network operation.

  Flexibility can support voltage control through both active and reactive power management (Khodabakhsh et al., 2025; Zegers and Natiesta, 2017). When voltage is too high, system operators may reduce local generation, charge storage devices, or increase flexible demand to lower the voltage. Conversely, when voltage is too low, discharging storage or reducing flexible loads can help raise the voltage. Additionally, inverter-based resources can provide or absorb reactive power to support voltage control more directly. At the distribution level, DSOs may activate flexible resources connected to their networks for voltage management, while at the transmission level, TSOs can also benefit from reactive power support provided by distribution-connected flexibility.

All of these system usages share the goal of maintaining a stable and reliable power system, but they may compete for the same flexibility resources (Wampack, 2023). A resource required for congestion management might therefore be unavailable for balancing, or an activation for balancing could exacerbate local congestion. For example, curtailing generation to relieve congestion can create an imbalance if insufficient balancing products are activated. Similarly, a balancing response can increase demand or generation locally, potentially intensifying congestion. In high renewable scenarios, such as during large offshore wind output, market signals may prompt many consumers to charge batteries or electric vehicles simultaneously. While the overall system balance might stay the same, local grids can become overloaded. Therefore, coordination is essential to avoid conflicts and to use flexibility more efficiently.

2.1.3. Local flexibility markets

Flexibility can be accessed through different regulatory and market arrangements. CEER distinguishes four main approaches: market-based procurement, rule-based approaches, network tariffs, and connection agreements (Council of European Energy Regulators [CEER], 2025). Among the available approaches, local flexibility markets (LEMs) provide a market-based way to organise flexibility and enable system operators to procure flexibility from distributed assets when this is more efficient than relying only on grid reinforcement or regulated interventions (Spiliotis et al., 2016). In this way, flexibility markets can complement network investments by optimizing the use of existing grid capacity. The European Commission estimates that flexibility capacity could avoid up to €5 billion in distribution grid investments each year (EPEX SPOT, 2022). By organising procurement through competitive bidding, local flexibility markets aim to reveal the cost-efficient sources of flexibility and to lower barriers to participation, particularly for smaller and distributed providers.

Local flexibility markets differ from broader electricity markets because they are organised around location specific network needs. While wholesale and balancing markets typically operate at the system level, local flexibility markets focus on constraints in specific parts of the network, such as congestion zones, feeders, substations, or connection points. This locational aspect is essential because flexibility can only address a local network problem if it is located in the appropriate part of the grid. Another important difference is the role of the DSOs as a buyer of flexibility. In traditional electricity markets, DSOs mainly operated the network and did not actively procure services from distributed resources. In LEMs, DSOs can become active procurers of local services, especially for congestion management, voltage control, reliability support, or network investment deferral (Chondrogiannis et al., 2022).

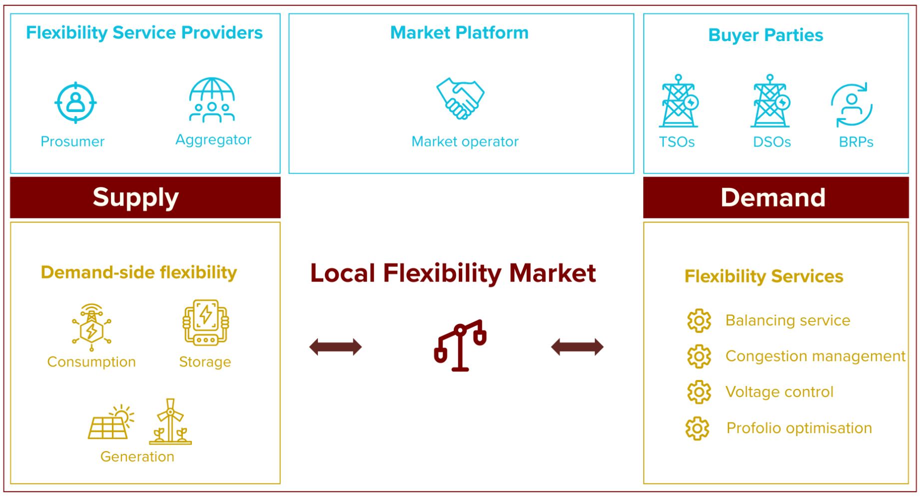

Figure 2.2: Local flexibility market.(based on EPEX SPOT, 2022)

The actors introduced in Section 2.1.2 interact through local flexibility markets in specific roles, as illustrated in Figure 2.2. System operators act as buyers of local services, while flexibility service providers, often aggregators or directly participating consumers, producers, and storage operators, act as sellers. In addition to these actors, local flexibility markets typically include a market platform as enabling infrastructure. The platform usually does not own flexibility itself but facilitates transactions by publishing local needs, registering offers, matching bids, communicating activation instructions, and supporting verification and settlement processes.

2.2. Market design diversity in Europe

Local flexibility markets in Europe are not organised under a single architecture. Country-level analyses reveal that national implementation pathways vary significantly in market structure, regulatory frameworks, and operational maturity (Jimeno et al., 2025). At the platform level, several commercial flexibility platforms operate across Europe, each featuring distinct trading procedures, settlement processes, and supported product types (Rodrigues et al., 2024). Despite their increasing deployment, LEMs in Europe face several persistent barriers as part of a multidimensional transition process shaped by institutional, regulatory, digital, market, and social dynamics (Jo, 2025).

2.2.1. Market architectures

Market architecture refers to how flexibility is traded, between which actors, over what time horizons, and through which selection and pricing rules. Existing European markets exhibit substantial diversity across these dimensions.

Table 2.1: Flexibility services procured by different actors in LEMs (Chondrogiannis et al., 2022)

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

- **Buyer parties**
  One key distinction in LEMs architecture concerns the buyer parties, as shown in Table 2.1. In DSO-led arrangements, the DSO is the primary buyer and utilizes flexibility to address distribution-level needs such as congestion management, voltage control, reliability enhancement, and network deferral. TSOs may also procure flexibility from distributed resources, but typically for system-wide balancing or transmission-level congestion management. BRPs can use flexibility for portfolio optimisation, for example, to reduce imbalance exposure or improve their market position. In practice, these roles can overlap because the same flexible resource may be valuable to multiple actors. This overlap creates a need for coordination, especially when DSO local needs interact with TSO balancing or transmission congestion requirements. Consequently, some markets remain primarily DSO-led, while others involve closer TSO–DSO coordination or mechanisms to avoid conflicting use of the same flexibility.

- **Market platform**
  Flexibility platforms can organise market-based procurement in various ways. A useful distinction is between market intermediaries and marketplaces (Frontier Economics, 2021). A market intermediary does not operate a full local market itself. Instead, it assists system operators and flexibility service providers in utilizing existing market arrangements from commercial platform providers and supports procurement but does not necessarily clear transactions or settle payments. GOPACS from Netherlands is an example of this type of platform, as it connects congestion management needs with bids available on connected intraday markets. A marketplace platform, on the contrary, is more self-contained and develops its own in-house market platform. It performs the core functions of a market, such as collecting bids, running auctions or trading sessions, clearing transactions, and supporting settlement between system operators and flexibility service providers. In this model, the platform is not only a gateway to another market but the main place where flexibility is traded. Examples include platforms such as NODES and Piclo Flex, which are designed to organise local flexibility procurement more directly. This distinction is important because the platform model influences how local flexibility procurement is coordinated with wholesale, balancing, and other system-service markets.

- **Procurement horizon**
  Long-term tenders are often used when flexibility is associated with network deferral, reliability, or predictable local constraints. These arrangements allow system operators to secure availability in advance, but they may be less integrated with short-term wholesale and balancing markets. In contrast, short-term trading platforms are more closely aligned with operational congestion management and redispatch. They allow flexibility offers to be submitted and selected closer to delivery but require more advanced digital infrastructure, greater liquidity, and well-defined coordination rules.

- **Trading, clearing, and pricing arrangements**
  Markets differ in their trading, clearing, and pricing arrangements (Chondrogiannis et al., 2022). Some use tender procedures in which bids are evaluated at fixed points in time, while others use auctions or continuous trading. Bids may be selected only on price or according to both economic and technical criteria. Pricing may follow pay-as-bid, pay-as-clear, or predetermined price arrangements. These design choices influence market transparency, liquidity, and the ability of flexibility providers to participate across multiple markets.

2.2.2. Barriers to market development

Despite the growing interest in LEMs, their deployment remains constrained by several regulatory, technical, economic, and operational barriers (Scrocca et al., 2026; Vigano et al., 2023). These barriers help explain why many European flexibility markets remain in pilot phases or show limited liquidity, even where the technical potential for distributed flexibility is significant.

- **Regulatory barriers**
  Regulatory fragmentation: There is a significant lack of standardised regulation at the European level, leading to heterogeneous national frameworks that complicate the scalability of market platforms.
  Undefined roles and responsibilities: Current regulations often lack clear definitions for the roles

of new market actors, such as aggregators and market operators.
Insufficient TSO–DSO coordination: There is a lack of formalised procedures for data exchange and priority setting between TSOs and DSOs, which is necessary to manage simultaneous activations.
Unfavourable tariffs: Existing regulated tariffs are often fixed and do not provide the price signals necessary to incentivise flexibility providers.
Incentive misalignment: Remuneration for DSOs often focuse on capital expenditures (CAPEX) for grid reinforcement rather than the operational expenditures (OPEX) required to run a flexibility market.

- **Technical barriers**
  Insufficient network observability: Many DSOs lack the digital tools and monitoring infrastructure, such as advanced smart meters and digitalised assets, needed to identify grid violations and quantify flexibility needs in real time.
  Baseline calculation issues: Accurately verifying the amount of flexibility delivered is a significant challenge. Baseline methodologies are often inaccurate, inconsistent across regions, and vulnerable to manipulation.
  Inadequate communication infrastructure: High costs and a lack of technical standards for real-time, secure communication between DSOs and distributed energy resources hinder automated dispatch.
  Strict prequalification processes: Prequalification is often technology specific rather than service focus, and rules designed for large, traditional plants, such as high minimum bid sizes, act as barriers to smaller demand-side resources.
  Legacy technology limitations: Many existing distributed energy resources, such as older inverters, have limited communication interfaces, making remote control difficult.

- **Economic barriers**
  Revenue unpredictability: Service providers face significant uncertainty regarding the frequency of activations and long-term profitability, making it difficult to build viable business cases.
  High initial investment costs: The deployment of necessary telemetry and field-level instrumentation is often too expensive for small-scale resources to justify participation.
  Difficulty in cost-benefit analysis: DSOs find it complex to accurately compare the costs of flexibility procurement, including imbalance costs and ICT investment, against traditional grid reinforcement.

- **Operational barriers**
  Low market liquidity: Insufficient participation from resources undermines market efficiency and makes it difficult for DSOs to solve local grid issues.
  Spatial and temporal mismatch: The geographic locations where grid congestion occurs often do not align with the locations of distributed energy resources capable of providing flexibility.
  Lack of know-how: There is a general need for specialised training for both DSO employees and aggregators to effectively manage and participate in these complex new market environments.

2.3. The Network Code on Demand Response

2.3.1. EU regulatory background

The regulatory background for flexibility markets in Europe has evolved gradually. Early electricity market legislation mainly recognised demand-side management as a tool for ensuring security of supply. With the introduction of the Third Energy Package, demand-side participation became part of the EU electricity policy agenda, although the role of distributed flexibility in market-based network operations remained limited.

A significant shift occurred with the Clean Energy for All Europeans package. The Electricity Regulation (EU) 2019/943 and the Electricity Directive (EU) 2019/944 placed active customers, demand response, and distributed energy resources at the center of the electricity market framework (EU, 2019; European Union [EU], 2019). Article 32 of Directive (EU) 2019/944 is particularly important for local flexibility markets, as it requires Member States to establish a regulatory framework that enables and incentivizes DSOs to procure flexibility services, including congestion management, through transparent, non-discriminatory, and market-based procedures, unless derogations apply. In parallel, Regulation (EU) 2019/943 provides the legal basis for developing network codes, including a network code on demand response.

Recent EU policy initiatives have reinforced the importance of flexibility. The European Green Deal, the Fit for 55 package, and REPowerEU have increased the emphasis on renewable integration, electrification, and energy system resilience (European Commission, n.d.-a, n.d.-b, n.d.-c). The 2023 EU Grid Action Plan further highlighted that grid investments must be complemented by more efficient use of flexibility, especially at the distribution level, where many distributed energy resources and new flexible loads are connected (European Commission, 2023). The European Grids Package, presented by the Commission in late 2025, continues this policy direction by proposing measures to modernise, expand, and optimise Europe's electricity infrastructure (European Commission, 2025).

The proposed Network Code on Demand Response represents the next step in this regulatory trajectory. Its development process began in June 2022, when the European Commission mandated ACER to prepare a framework guideline on demand response. After a public consultation, ACER submitted the guideline in December 2022, and the Commission approved it in March 2023. Subsequently, the EU DSO Entity and ENTSO-E drafted the proposed network code, which was submitted to ACER in May 2024. Following revisions and stakeholder consultations in autumn 2024, ACER submitted its final proposal to the European Commission on 7 March 2025. Once adopted, the code is expected to become legally binding (ACER, 2025c; Touhey, 2025).

2.3.2. Objectives and scope

ACER's final NCDR proposal consists of several annexes. Annex 1 contains the amended Demand Response Network Code itself and is the main regulatory text analysed in this thesis. The other annexes either provide tracked change versions, propose amendments to related electricity regulations, such as the Electricity Balancing Regulation, System Operation Regulation and Demand Connection Network Code, or explain the reasons for these revisions and the consultation responses (ACER, 2025c). Since this thesis focuses on local flexibility markets and the market-based procurement of local services, Annex 1 is the primary document used for analysis. For simplicity, Annex 1 is referred to as the NCDR in the remainder of this thesis.

The proposed NCDR establishes a unified regulatory framework for demand response, energy storage, distributed generation, and demand curtailment, all of which belong to demand-side flexibility. The code scope is comprehensive and applies to TSOs, DSOs, regulatory authorities, ACER, ENTSO-E, the EU DSO Entity, delegated third parties, and relevant market participants. It also covers transmission and distribution systems throughout the Union, excluding non-interconnected island systems.

The objectives of the NCDR are both market-oriented and system-oriented. On the market side, the code aims to remove barriers to participation, support non-discrimination and technology neutrality, and ensure that relevant resources can access electricity markets, including balancing, congestion management, and voltage control. On the system side, it seeks to support effective competition and efficient market functioning without compromising power system security. Additionally, it establishes European principles for assessing the need for market-based procurement and the use of local services, as well as clearer digital processes, roles, and responsibilities at the European level.

The NCDR will be implemented through a combination of EU-level and national-level processes. Within twelve months after the Regulation enters into force, Member States must establish national rules of procedure for developing common proposals regarding national terms and conditions or methodologies. Unless a Member State specifies otherwise, the regulatory authority will be the designated entity responsible for this task. These national procedures must detail which system operators are involved, how they are represented, how decisions are made, how stakeholder involvement is safeguarded, how transparency is ensured, and how amendments can be proposed. After these procedural rules are established, system operators, ENTSO-E, and the EU DSO Entity are responsible for developing the terms and conditions or methodologies required by the code. These proposals must include implementation timelines and expected impacts and must be submitted either to ACER or to the competent national regulatory authority for approval. Union-wide methodologies, such as the methodology for simplifying product prequalification and the European table of equivalences, are approved by ACER. Other areas, including baselining methods, terms and conditions for local service providers, the flexibility information system, and TSO–DSO and DSO–DSO coordination, are approved at the national level. Regulatory authorities or ACER must decide on submitted proposals within six months.

Stakeholder involvement is also integrated into the implementation procedure. Draft terms and conditions or methodologies must undergo a consultation period of at least one month, during which the responsible entities are required to explain how stakeholder feedback has been taken into account. Additionally, ACER, ENTSO-E, and the EU DSO Entity are expected to facilitate broader stakeholder engagement on demand response, secure system operation, and other implementation issues.

The NCDR illustrates the harmonisation logic across Member States. The code does not target a specific market segment, nor does it enforce a uniform market design across all Member States. Some elements are harmonised at the EU level, while others are harmonised within each Member State through national terms and conditions. Therefore, the NCDR establishes a common regulatory framework while allowing for national variations in the detailed design of local flexibility markets.

2.3.3. Structure and main themes

The NCDR is organised into a broad set of titles that cover both market design and supporting governance arrangements.

- **TITLE I - GENERAL PROVISIONS**
  This title establishes the subject matter and scope, defining rules for demand response, energy storage, and distributed generation to enhance market integration and competition. It provides essential definitions, such as 'metering point' and 'baseline,' and establishes the administrative framework for national rules, stakeholder consultation, cost recovery, and confidentiality.
- **TITLE II - GENERAL REQUIREMENTS FOR MARKET ACCESS**
  This title addresses the fundamental requirements for market entry, requiring system operators to develop national terms for service providers that simplify access and avoid process duplication. It outlines how settlement volumes are calculated, establishes a framework for data validation from dedicated measurement devices, and defines the rules for calculating and validating baselines used to measure delivered services.
- **TITLE III - QUALIFICATION REQUIREMENTS AND PROCESSES**
  Divided into two chapters, this title outlines the technical and data driven qualification procedures. Chapter 1 addresses the verification and prequalification of service providers and units, introducing a table of equivalences to streamline approvals. Chapter 2 focuses on flexibility data management, emphasizing the need for a national flexibility information system to handle registrations, status updates, and the transfer of units between providers.
- **TITLE IV - MARKET BASED PROCUREMENT OF LOCAL SERVICES**
  This title establishes the rules for procuring local services, requiring system operators to assess flexibility needs at least every two years as alternatives to grid expansion. It defines the principles for procurement, coordination with wholesale markets, and pricing and settlement mechanisms, while mandating that derogations from market-based mechanisms be granted only under specific, transparent conditions.

- **TITLE V - OWNERSHIP OF ENERGY STORAGE FACILITIES BY SYSTEM OPERATORS**
  This title sets strict conditions for system operators' ownership of storage assets, emphasizing that these services should generally be market-based and competitive. It mandates open and non-discriminatory tendering procedures and permits shared ownership with third parties. However, it requires regular regulatory reviews to phase out operator ownership if a third party demonstrates capable interest.
- **TITLE VI - DISTRIBUTION NETWORK DEVELOPMENT PLANS**
  This title requires each DSO to establish a Distribution Network Development Plan (DNDP) covering a horizon of five to ten years. These plans must utilize plausible future scenarios and include cost-efficient measures, such as necessary infrastructure investments and the integration of local services, to postpone or alleviate the need for traditional grid reinforcement.
- **TITLE VII - TSO-DSO COORDINATION AND DSO-DSO COORDINATION**
  This title outlines the framework for cooperation between system operators, requiring national terms for coordination to ensure system security. It details the creation of DSO observability areas, processes for forecasting and solving congestion, grid prequalification procedures, and principles for high-quality data exchange to optimize the use of available resources.
- **TITLE VIII - DATA EXCHANGE REQUIREMENTS FROM SERVICE PROVIDERS**
  This title outlines the obligations of service providers regarding data provision, emphasizing that requests must be necessary, relevant, and avoid duplication. Service providers are responsible for submitting high-quality structural, scheduling, and near real-time data to operators through the national flexibility information system to support secure grid operations.
- **TITLE IX - REPORTING AND MONITORING**
  This title establishes a Europe-wide oversight framework, requiring ENTSO-E and the EU DSO Entity to publish biennial reports on the status of demand response and local markets. ACER is tasked with monitoring the implementation of the Regulation and mandates that all relevant entities maintain a standardized digital data archive to facilitate market analysis.
- **TITLE X - TRANSITIONAL AND FINAL PROVISIONS**
  This title provides the roadmap for implementation, allowing for interim IT solutions while the permanent flexibility information systems are being developed. It sets strict deadlines for achieving full system functionality, generally within three years of the terms' approval, and confirms that the Regulation becomes binding across all Member States 20 days after its official publication.

This chapter has provided the conceptual and regulatory background for the thesis. It explained the role of demand-side flexibility in electricity systems, introduced local flexibility markets, and discussed the main barriers to their development. Additionally, it presented the NCDR as an upcoming EU regulation concerning demand response and local service procurement. This background lays the foundation for the next chapter, which extracts the NCDR requirements relevant to local flexibility markets and organises them into analytical categories.

3

Requirement framework

This chapter develops the requirements framework used in the thesis. It first explains how the relevant NCDR provisions were extracted and summarised into a structured requirements table. It then describes how these requirements were organised into five main categories and fifteen subcategories. The extraction table is provided in Appendix A to address SQ1. Next, the chapter explains how selected categories were translated into assessment dimensions, indicators, and questions for the comparative case analysis. The NCDR market requirements assessment framework is presented as the answer to SQ2. In this way, the chapter bridges the legal text of the NCDR and the empirical assessment of current flexibility market arrangements.

3.1. Category development

The development of the requirement framework began with the creation of a requirement extraction table. NCDR Annex 1 contains ten titles and fifty-eight articles (ACER, 2025a). Before these provisions could be extracted and coded, analytical categories had to be defined to organise them. This was necessary because the legal structure of the NCDR does not directly correspond to the structure of a local flexibility market. Requirements related to a single market function may appear across several titles and articles, while some legal titles are only partially relevant to local flexibility markets. Therefore, the categories were developed before the detailed extraction was completed. They provided the coding structure used to determine which provisions were relevant and how each extracted requirement should be organised in the table.

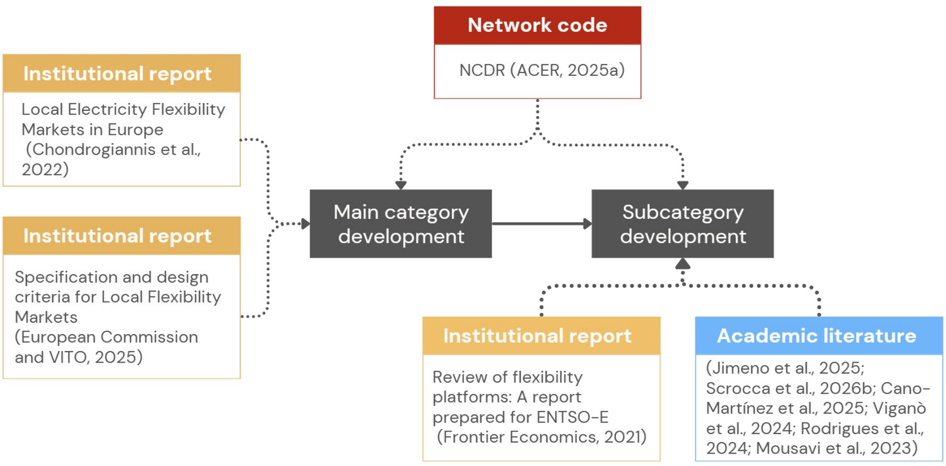

Figure 3.1: Sources and process for developing the NCDR assessment categories.

Figure 3.1 illustrates the category development process. This process combined three types of sources: the NCDR text, institutional reports on local flexibility markets, and academic literature. The NCDR provided the regulatory content to be assessed, institutional reports offered practical market design structures, and academic literature was used to verify and refine the concepts applied in the categories.

The main categories were developed primarily from two institutional reports on local flexibility markets. The JRC report organises LFMs around pre-qualification procedures, flexibility product design, market architecture, activation and settlement procedures, and lessons learned (Chondrogiannis et al., 2022). The European Commission and VITO report employs a similar structure, discussing product design, market design, prequalification, procurement, activation, settlement, gaming, and governance (European Commission and VITO, 2025). Although these reports were not written specifically for the NCDR, they provide a practical way to understand LFMs as a set of market design and operational functions. Based on these sources, five main categories were selected: product design, pre-qualification, procurement, activation and settlement, and governance.

The subcategories were developed by integrating the five main market design categories with the regulatory themes identified in the NCDR. This process did not involve a direct mapping of NCDR titles. Instead, the titles and article names were used to determine which regulatory functions were relevant within each main category. Some functions corresponded to existing LFM concepts, such as product attributes, pre-qualification, procurement, measurement, verification, and settlement. Other functions reflected more specific NCDR concepts that are less prominent in earlier LFM literature and were added as necessary. For example, the Flexibility Information System was included under governance, because it supports information exchange and market transparency. Academic literature and additional institutional reports were then used to check whether the subcategories covered the main design elements discussed in the LFM literature. These sources highlight issues such as timeframes, baselining, platform functions, settlement, and TSO–DSO coordination (Frontier Economics, 2021; Scrocca et al., 2026; Jimeno et al., 2025; Cano-Martínez et al., 2025; Viganò et al., 2024; Rodrigues et al., 2024; Mousavi et al., 2023). Ultimately, fifteen subcategories were developed within the five main categories.

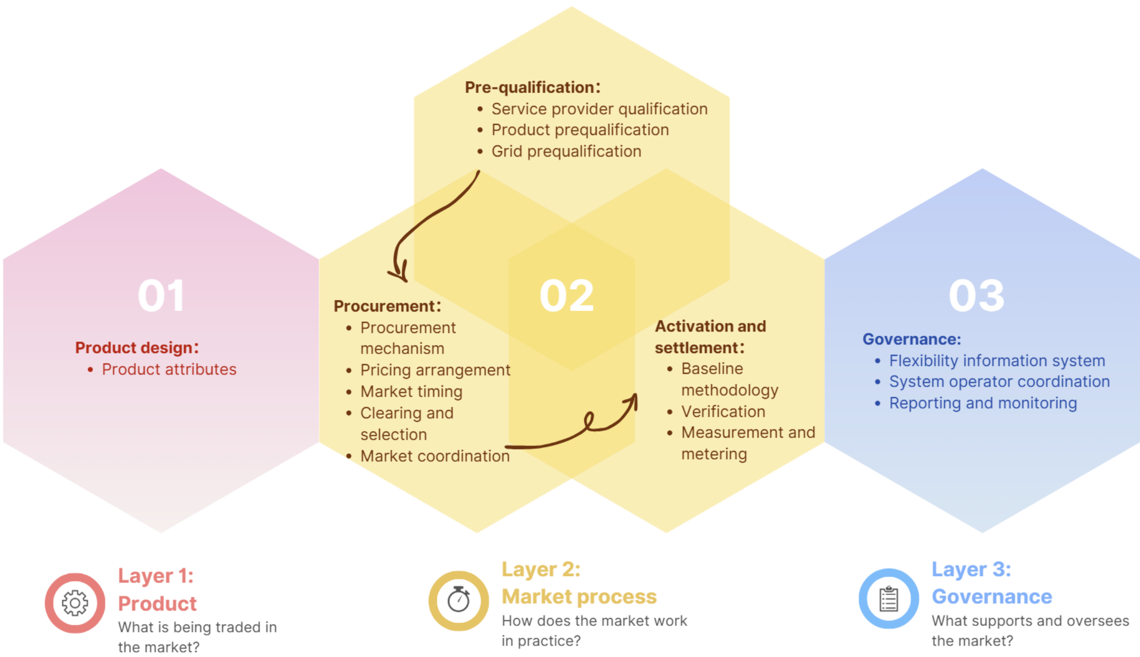

Figure 3.2: Analytical layers and category structure for coding NCDR requirements.

This structure can also be understood through three analytical layers, as shown in Figure 3.2. The first layer is the product layer, which addresses what is being traded. The second layer is the market process layer, which explains how the market operates in practice, from pre-qualification to procurement, activation, and settlement. The third layer is the governance layer, which covers the mechanisms that support, coordinate, and oversee the market. These layers clarify the logic of the category structure, while the five categories and their subcategories provide the basis for requirement coding, which was used for the requirement extraction table discussed in Section 3.2.

3.2. NCDR requirement extraction

After developing the category structure, the next step was to extract the NCDR provisions relevant to each category and subcategory. The purpose of this step was to create a requirement extraction table. This table provides a traceable link between the legal text of the NCDR and the analytical categories developed in Section 3.1.

The extraction was based on a detailed, article by article review of NCDR Annex 1. The selection of provisions was guided by the category structure. For each subcategory, relevant provisions were identified and coded into the extraction table. In some cases, the relevant provisions were easy to identify because the article titles directly matched the subcategory. For example, baseline-related requirements were mainly identified from Article 14, *National terms and conditions for baselining methods*, and Article 15, *Validation of the baseline*. These articles correspond directly to the baseline methodology subcategory. In other cases, relevant provisions were distributed across several articles. For instance, the Flexibility Information System is most directly addressed in Article 24, *National terms and conditions for a flexibility information system*. However, related requirements also appear in Articles 25–28, which further specify the development, content, operation, and use of the system. These provisions were therefore grouped under the same subcategory because they serve the same analytical function. This approach was also applied to other cross-article topics. Therefore, the extraction process used a functional reading of the NCDR. Table 3.1 shows how the extracted provisions are distributed across the NCDR source titles. The table shows that some subcategories are mainly based on one title, while others draw on several titles.

Table 3.1: Mapping NCDR source titles to analytical categories and subcategories

Main category	**Subcategory**	**NCDR TITLE**						
		I	**II**	**III**	**IV**	**VII**	**VIII**	**IX**
Product design	Product attributes				•			
Pre-qualification	Service provider qualification	○	•	•				
	Product prequalification	○	•	•				
	Grid prequalification	○		•		•		
Procurement	Procurement mechanism	○			•			
	Pricing arrangement				•			
	Market timing				•			
	Clearing and selection				•			
	Market coordination				•			
Activation and settlement	Baseline methodology	○	•					
	Verification	○	•	•				
	Measurement and metering		•		•		•	
Governance	Flexibility information system	○		•				
	System operator coordination	○				•		
	Reporting and monitoring							•

Note: • = main source title; ○ = supporting source title.

Each relevant provision was recorded as either a single requirement or a requirement block. A requirement block was used when multiple subpoints within the same paragraph served the same regulatory function. This approach avoided unnecessary fragmentation of the extraction table while preserving the meaning of the legal text.

Each provision was then summarised in plain language because the NCDR provisions are often long, legalistic, and linked to other EU regulations. The extraction table does not reproduce the full legal text. Instead, it summarises the main requirements in a format suitable for analysis. References to other legal instruments were kept only when necessary for understanding the requirements.

For each extracted requirement, the table records the title, article, paragraph reference, requirement summary, responsible actor, main category, subcategory, key aspect, and analytical insight or implication. Responsible actors were simplified into broad groups, such as system operator, regulatory authority, service provider, ENTSO-E, and EU DSO Entity, to maintain consistency in coding across different sections of the NCDR.

The columns for key aspect and analytical insight were added to enhance the extraction table's usefulness for subsequent analysis. The key aspect identifies the specific issue addressed by each provision, such as the baseline validation process or responsibility for production verification. The analytical insight explains why the provision is important for the development of LFMs. For example, Article 29(1) was coded as an ex-ante basis for market-based procurement because it requires system operators to assess the need for services from demand response, energy storage, or other resources as alternatives to system expansion.

The final requirement extraction table serves two purposes. First, it provides a structured overview of the NCDR provisions relevant to local flexibility markets. Second, it establishes the evidence base for the subsequent selection of assessment subcategories and indicators. The complete requirement extraction table is included in Appendix A. Based on the extraction, the relevant NCDR requirements were organised into all categories. These NCDR contents of these categories are explained in the following section.

3.3. Requirement categories

After the requirement extraction, the extracted NCDR provisions were grouped under the categories and subcategories developed in Section 3.1. This section uses these grouped provisions to explain what the NCDR covers in each category.

The discussion is organised around five main categories: product design, pre-qualification, procurement, activation and settlement, and governance. Each category is explained through the NCDR provisions assigned to its subcategories. Together, they show how the NCDR addresses both local flexibility products and the broader processes needed for market access, procurement, settlement, coordination, and monitoring.

3.3.1. Product design

Product design captures requirements related to what is traded in a local flexibility market. The NCDR requires local products to be described through a common set of attributes. This allows local products to reflect national and local system needs, while still using a more comparable structure across Member States.

product attributes refers to the technical and operational characteristics that define a local flexibility product. These include, for example, timing, location, direction, quantity, divisibility, and data exchange requirements. For voltage control, the NCDR also includes additional attributes related to reactive power and voltage response. Product design under the NCDR provides a common structure for defining local services, while leaving detailed product choices to national implementation.

3.3.2. Pre-qualification

Pre-qualification captures requirements related to market access and eligibility. It determines whether a participant, product, or resource is allowed to provide balancing or local services. In local flexibility markets, pre-qualification is important because system operators need reliable services, but the process should not be so complex that it discourages participation (Chondrogiannis et al., 2022; European Commission and VITO, 2025).

The NCDR divides pre-qualification into several related checks that operate at different levels. The first check determines whether a market participant can become a service provider. The second assesses whether a service providing unit or group can deliver a specific product. The third evaluates whether the activation of the service is compatible with secure network operation. Based on this logic, this main category is divided into three subcategories: service provider qualification, product prequalification, and grid prequalification.

Service provider qualification refers to the eligibility of a market participant. It determines whether the participant meets the administrative, technical, and data-related requirements necessary to provide balancing or local services. The NCDR also aims to simplify this process where possible, for example, by avoiding unnecessary repeated qualifications when a provider is already qualified for a similar service.

Product prequalification refers to the ability of a service providing unit or group to deliver a specific product. It assesses whether the resource or portfolio can meet the relevant product requirements before service delivery. The NCDR also allows lighter processes in some cases, such as product verification, where compliance is evaluated after delivery rather than through a full ex-ante prequalification process.

Grid prequalification relates to the network impact of service delivery. It assesses whether activation of a service could create congestion, voltage issues, or other operational security problems for the connecting or impacted system operators. This subcategory is especially important for LFMs, as a service that helps one network area may create problems in another. Therefore, grid prequalification connects market participation with system operator coordination and network security.

3.3.3. Procurement

Procurement captures requirements related to how system operators acquire local flexibility services through market-based processes. In local flexibility markets, procurement includes how system needs are identified, how bids are submitted and selected, how prices are determined, and how the process interacts with other electricity markets (European Commission and VITO, 2025).

The NCDR treats market-based procurement as the main approach for local services, unless a derogation applies. It requires procurement rules to be objective, transparent, non-discriminatory, and technology-neutral. Based on the extracted requirements, this category is divided into five subcategories: procurement mechanism, pricing arrangement, market timing, clearing and selection, and market coordination.

Procurement mechanism refers to the basic structure through which local services are procured. It covers the need assessment for local services, the conditions under which market-based procurement should be used, and the rules that organise the procurement process. This subcategory links local flexibility procurement to network planning, because system operators must assess whether demand response, storage, or other resources can serve as alternatives to system expansion.

Pricing arrangement refers to how service providers are remunerated. The pricing arrangements should support cost-efficient activation, reflect local market conditions, and provide incentives for market development. This allows different approaches, such as energy-only payments or capacity-based payments, depending on the product and the local context.

Market timing refers to the timeframes and deadlines that structure the procurement process. This includes registration, bidding, gate closure, selection, activation, and publication of results. Timing is important because local flexibility procurement must be coordinated with day-ahead, intraday, and balancing markets. It affects when providers can participate and how local procurement interacts with other market processes.

Clearing and selection refers to how bids are matched with system needs and how the final procurement outcome is determined. In LFMd, bid selection is not only an economic process based on price. It also has a technical dimension, because selected bids must actually resolve the relevant congestion or voltage issue. Therefore, this subcategory covers both market selection and the network relevance of the selected bids.

Market coordination refers to how local flexibility procurement interacts with other markets and flexibility mechanisms. The same flexible resource may participate in local, intraday, day-ahead, balancing, or flexible connection agreements. Therefore, the NCDR requires rules to manage these interactions, avoid double selection or double activation, and preserve consistency between market outcomes and system operation.

3.3.4. Activation and settlement

Activation and settlement capture requirements related to what happens after flexibility has been procured. Activation concerns how a selected service is called upon. Settlement concerns how delivered flexibility is measured, verified, and remunerated. This stage is important because market participants need to trust that service delivery can be proven and paid for in a transparent way. However, LFMs make this process challenging. Flexibility may come from many distributed resources, which creates practical questions about baselines, measurement data, verification, and settlement rules (Chondrogiannis et al., 2022; European Commission and VITO, 2025). Based on the extracted NCDR requirements, this category is divided into three subcategories: baseline methodology, verification, and measurement and metering.

Baseline methodology refers to how the reference level of electricity consumption or injection is defined. It provides the counterfactual against which delivered flexibility is measured. This is important because flexibility delivery is often calculated as the difference between actual measured behaviour and the baseline. If the baseline is unclear or unreliable, settlement accuracy and trust in the market may be weakened. Under the NCDR, baseline methodology includes the definition, calculation, validation, and evaluation of baseline methods. It also includes quality principles, data requirements, and the roles of relevant actors. This makes baseline methodology a central part of settlement and market confidence.

Verification refers to the process of checking whether a flexibility service has met the required conditions. It is mainly an ex-post process, because it assesses whether the delivered service complied with the relevant product requirements after activation. Verification is therefore placed under activation and settlement rather than pre-qualification. LEMs need a reliable way to confirm that the procured service was actually delivered. At the same time, the process should not become too burdensome for service providers. Therefore, the NCDR connects verification to defined procedures, data requirements, possible activation tests, and reassessment when relevant changes occur.

Measurement and metering refers to the data and devices used to quantify flexibility delivery. Measurement data are needed to determine whether a service was delivered, how much flexibility was provided, and how the service should be settled. This may involve connection meters, smart meters, dedicated measurement devices, or other data sources. This subcategory is closely related to baseline methodology and verification, but it focuses specifically on measured data and technical data flows. Under the NCDR, measurement and metering requirements support baseline validation, activated volume calculation, settlement, and data exchange between service providers and system operators.

3.3.5. Governance

Governance captures requirements that support, coordinate, and oversee LFMs. The previous categories describe the market process itself, such as product design, procurement, activation, and settlement. Governance focuses on the institutional and digital arrangements that make this process possible. In the NCDR, governance includes the Flexibility Information System, system operator coordination, and reporting and monitoring.

Flexibility Information System refers to the digital system used to record and exchange information related to flexibility market participation. It includes information on service provider qualification, product prequalification, product verification, grid prequalification, and the switching of controllable units. This subcategory is placed under governance because the system supports several parts of the market process at the same time. Since LFMs require many actors to exchange consistent, real-time information, a common access point and harmonised digital interfaces can reduce administrative complexity and support more transparent participation.

System operator coordination refers to structured cooperation between TSOs and DSOs, and between DSOs. Its purpose is to ensure that the use of flexibility in one network does not create congestion, voltage issues, or security problems in another network. This subcategory covers coordination arrangements, DSO observability areas, forecasting and detection of network issues, grid prequalification, temporary limits, trade-position consistency, and coordination-related data exchange. Since many flexible resources are connected at the distribution level, their activation may affect both distribution and transmission networks. System operator coordination can connect local market operation to secure system operation.

Reporting and monitoring refers to the mechanisms used to track NCDR implementation and the development of demand response over time. This includes reporting on local service procurement, derogations, procured products, baselining methods, and the integration of demand response into electricity markets. This subcategory is placed under governance because reporting and monitoring support transparency, regulatory oversight, and learning during implementation. They also make it possible to compare progress across Member States and identify where further harmonisation may be needed.

3.4. Assessment framework

The previous section identified five main categories and fifteen subcategories through which the NCDR governs market-based procurement of local flexibility. These categories provide a structured overview of the regulatory expectations placed on system operators and market participants. However, the aim of this thesis is not to conduct a comprehensive compliance audit of every NCDR provision but to develop a focused framework for comparing different national arrangements and understanding the potential implications of the NCDR for their future development.

This distinction is important. A compliance audit requires a detailed assessment of all requirements. In contrast, a comparative case study necessitates a more selective framework, focusing on areas that reveal meaningful differences across cases and can be evaluated using available evidence. Therefore, the assessment framework presented in this section is a deliberate subset of the broader NCDR requirement structure. It retains the subcategories most useful for comparative analysis while excluding those that either offer little variation across cases or require evidence that is not publicly accessible.

3.4.1. Selection principles

Three principles guided the selection of the assessment subcategories.

First, **analytical depth**. A subcategory is retained only when it helps explain meaningful differences in how national markets interpret NCDR requirements. Some subcategories are useful for checking technical compliance, such as whether required product attributes are listed. However, they provide less insight into how the market is institutionally organised or how it operates in practice.

Second, **evidence availability**. A subcategory is retained only when comparable public evidence is available across the selected cases. The country cases vary in the level of detail and transparency of their public documentation. If a subcategory is well documented in one case but largely obscured in another, it becomes difficult to assess it consistently.

Third, **comparative variation**. A subcategory is retained only if it can reveal meaningful differences across the selected cases. Some NCDR requirements are important, but current market arrangements do not yet differ sufficiently to make them useful for comparative assessment. They may reveal the same future implementation gap across all cases, rather than help explain differences between national market designs.

These principles were applied collectively. A subcategory was included only if it was important for NCDR implementation, demonstrated meaningful variation across cases, and could be assessed using available sources. This process resulted in the selection of four subcategories: procurement mechanism, market coordination, baseline methodology, and TSO–DSO coordination.

3.4.2. Selected subcategories

Procurement mechanism forms the foundation of the assessment framework. The NCDR establishes market-based procurement as the default model for local flexibility services. The first question, therefore, is whether each case has adopted a formal procurement mechanism and what form this mechanism takes. This subcategory captures whether procurement is organised through long-term tenders, short-term market platforms, or hybrid arrangements. It also considers how procurement rules structure market access and how procurement is linked to identified grid needs. This subcategory is both central to the NCDR and relatively easy to assess because tender documents, platform descriptions, regulatory reports, and operator publications are often publicly available.

Market coordination focuses on how local flexibility procurement interacts with the broader electricity market environment. The NCDR requires that local procurement be coordinated with day-ahead, intraday, and balancing markets. This coordination is necessary to avoid double activation, inconsistent market positions, and barriers to value stacking. This category is analytically important because countries vary significantly in how they integrate local flexibility with other markets. Evidence on market coordination is not always consolidated in a single document but can usually be reconstructed from market rules, operator publications and platform documents.

Baseline methodology addresses how delivered flexibility is measured and settled. A credible baseline is essential to verify delivery and calculate remuneration. The NCDR emphasises the importance of this issue by requiring national baselining methodology and validation rules. Across the cases studied, baseline methodology represents one of the most significant implementation challenges, though it manifests in different forms. In some instances, baseline rules are explicitly defined in settlement documents. In others, the reference position may be implicit and linked to market schedules. Although evidence regarding baselines can be difficult to obtain, the issue is sufficiently prominent across cases to allow for meaningful comparison.

TSO–DSO coordination represents the institutional layer underlying the other three subcategories. Local flexibility procurement cannot function effectively without coordination between TSOs and DSOs. Without such coordination, local activations may conflict with balancing needs, create issues in neighbouring networks, or affect trade positions. Title VII of the NCDR addresses these challenges through requirements related to observability areas, grid prequalification, temporary limits, trade-position consistency, and data exchange. Evidence on TSO–DSO coordination is moderately accessible. Although full coordination arrangements are rarely described in a single document, regulatory texts, consultation papers, and market design documents collectively provide context information to assess the overall framework in each case.

3.4.3. Excluded subcategories

Several NCDR-derived subcategories were not selected for detailed case assessment. This does not mean that they are unimportant. Rather, they were excluded because they are less suitable for the comparative purpose of this thesis.

Some subcategories were excluded because they offer **limited analytical depth** for this comparison. ***Product design*** is important for compliance, but it mainly involves checking whether local products include required attributes. It is therefore less useful for explaining differences in national market architecture. ***Market timing*** focuses on when procurement takes place. These timing rules are important for each market, but they mainly show procedural differences across cases. For example, a long-term tender and a short-term auction may have different timelines, but this does not necessarily reveal a deeper difference in regulatory approach. ***Clearing and selection*** concerns how submitted bids are evaluated, ranked, and awarded. It is important in principle, but public information is uneven across the cases. Some countries publish detailed selection criteria, while others only state that procurement is transparent and non-discriminatory. Even when information is available, the comparison would mostly describe procedural details rather than explain how countries interpret the NCDR's market-based requirements.

Other subcategories were excluded because of **evidence limitations**. ***Service provider qualification*** was excluded mainly because current LFMs often apply only basic entry requirements, such as legal, administrative, or commercial eligibility. More detailed service provider qualification requirements, including financial checks or harmonised qualification procedures, remain rare or inconsistently documented. As a result, public information across cases is too uneven to support a robust comparison. ***Product prequalification*** is important, but remains relatively simple in many current LFMs. Providers typically demonstrate their ability to meet product requirements by submitting a bid, while formal ex-ante tests are generally avoided due to the potentially high costs, especially for smaller flexible assets. Live markets may publish product sheets, but these usually describe product characteristics rather than a comprehensive NCDR style product prequalification process. ***Grid prequalification*** is even less developed in current local flexibility markets. Many surveyed LFMs do not yet assess the impact of flexibility activation on other grids, partly because current market volumes remain small. As a result, formal grid prequalification procedures are often absent, simplified, or still under development (). Since grid prequalification requires detailed network security information that is rarely publicly available, it is difficult to assess consistently through document analysis alone. *Pricing arrangement* is also conceptually important, especially for understanding FSP incentives. However, detailed information on price caps, remuneration formulas and capacity versus energy payment structures is uneven across cases. This makes systematic comparison difficult.

Finally, some subcategories were excluded because they currently exhibit **limited variation** across the selected cases. The ***flexibility information system*** and ***reporting and monitoring*** requirements are important NCDR innovations, but none of the selected cases has yet implemented a fully NCDR compliant version of these arrangements. Assessing them would therefore primarily reveal the same future implementation gap across all cases. While they remain important for future evaluation, they are less useful for the present comparative analysis.

3.4.4. From subcategories to indicators

The four selected subcategories are operationalised through a set of indicators derived from the NCDR provisions identified in the previous sections. Each indicator represents a broader regulatory expectation rather than a single legal provision. These indicators are then reformulated as assessment questions that can be applied consistently across the selected country cases. The transformation from requirement to assessment question follows a consistent logic. For the requirements from the NCDR, the indicators capture the regulatory issue underlying each requirement, and the assessment questions determine whether this issue is evident in the case under study. The purpose is to assess whether current market arrangements reflect the direction of the NCDR in a manner observable from public documents and interview evidence. This approach makes the framework suitable for comparative analysis.

The complete mapping of selected dimensions, indicators, derived articles, and assessment questions is presented in Table 3.2. This table serves as the operational version of the assessment framework, linking the selected NCDR requirement areas to specific questions that can be asked in each case.

Two examples illustrate how the transformation was carried out. The first example is indicator PM1. Article 29 establishes market-based procurement as the default approach for local services, while Articles 32 and 35 require procurement rules to be defined in a structured way. These provisions are translated into the indicator *existence of a formal market-based procurement framework*. The corresponding assessment question asks whether the case has a formal and explicit framework for market-based procurement of local services, including clear procurement rules and procedures. This formulation not only inquires whether a market exists but also whether the procurement mechanism is sufficiently formalised and observable.

Another example is Article 34, which generates indicator MC4 and addresses the interaction between local procurement and other electricity markets. It allows bids to be submitted in multiple markets while implementing safeguards against double selection and double activation. These provisions are translated into indicators related to market coordination and protection against inconsistent positions. Consequently, the assessment questions ask whether the case enables cross-market participation and includes rules to prevent the double use of the same flexibility. This reformulation is useful because different markets may address the issue in various ways. One case may depend on an intermediary platform, another on contractual restrictions, and a third on formal bid-forwarding rules.

The indicator table is used in the case study analysis to guide evidence collection and scoring. For each country case, the same assessment questions are applied to the available documents. Evidence is then recorded for each indicator, together with a qualitative judgement of alignment. The framework is applied to the selected country cases in Chapter 5.

Table 3.2: NCDR market requirement assessment framework

Subcategory	Indicator No.	Indicator	Derived main article(s)	Assessment question
Procurement mechanism	PM1	Existence of a formal market-based procurement framework	Art. 2(7); Art. 29(2); Art. 32(1); Art. 35(1)	Does the case have a formal and explicit arrangement for market-based procurement of local services, including clear procurement rules and procedures?
	PM2	Ex-ante assessment and justification of procurement need	Art. 29(1); Art. 29(3)–(4)	Does the case arrangement require an ex-ante assessment of flexibility needs and a justified decision process when market-based procurement is not applied or is derogated from?
	PM3	Quality, fairness, and openness of procurement rules	Art. 32(2); Art. 33(1)–(2)	Are the procurement rules designed to be objective, transparent, non-discriminatory, technology-neutral, and supportive of fair and efficient market access?
	PM4	Institutional and operational design of procurement	Art. 32(3)(a); Art. 33(5)(e)–(g); Art. 35(1)	Are the responsibilities, operational processes, and supporting systems for procurement clearly defined and practically implemented?
Market coordination	MC1	Coordination between local procurement and other electricity markets	Art. 32(3)(b); Art. 34(1)	Does the case arrangement clearly define how local-service procurement interacts with day-ahead, intraday, and balancing markets, including the form of interrelation between them?
	MC2	Coordination between flexible connection agreements and local service markets	Art. 31(2)(a),(c); Art. 32(3)(d)	Does the case arrangement include a clear mechanism for coordinating flexible connection agreements with local-service products where both coexist?
	MC3	Cross-market participation arrangements	Art. 33(6)–(7); Art. 34(3)	Does the case arrangement clearly regulate bid forwarding or participation across markets?
	MC4	Protection against overlap and inconsistent positions	Art. 34(2)–(3)	Does the case arrangement include clear rule to avoid double selection, double activation, or inconsistencies when the same bids or resources participate across multiple markets?
Baseline methodology	BM1	Existence of a formal baseline methodology	Art. 2(2)–(3); Art. 14(1), 14(4)	Are baseline methods formally defined for the relevant products and resource types, and are they part of a common system operator process?
	BM2	Clarity of baseline institutional responsibilities	Art. 14(2)(a)	Are the roles and responsibilities for developing, implementing, and proposing baseline methods clearly defined?
	BM3	Existence of a clear baseline validation process	Art. 14(2)(b); Art. 15(2)–15(3)	Is there a defined process for validating the baseline, including clear authority to request and use the data needed for validation?
	BM4	Data requirements and data sharing	Art. 14(2)(c)–(d); Art. 15(1)–15(3)	Does the case arrangement clearly specify the minimum data needed for baselines, the required data granularity, and the arrangements for sharing and accessing baseline-related data?
	BM5	Quality of baseline methods	Art. 14(2)(e); Art. 14(3)(a)–(e)	Does the baseline methodology meet the required quality principles of transparency, accuracy, unbiasedness, and consideration of compensation and rebound effects?
TSO–DSO coordination	SOC1	Existence of a formal national coordination framework	Art. 45(1)–(3)	Does the case arrangement establish formal national terms and conditions for TSO-DSO and DSO-DSO coordination, with clear objectives and minimum coordination content?
	SOC2	Establishment and maintenance of DSO observability areas	Art. 2(15); Art. 46(1), 46(3)–(6)	Does the case arrangement require DSOs to define, maintain, and periodically reassess observability areas in cooperation with relevant system operators?
	SOC3	Coordinated forecasting and detection of local system issues	Art. 47(1)–(2), 47(4)	Does the case arrangement provide a coordinated process for forecasting and detecting congestion and voltage issues?
	SOC4	Coordination for solving congestion and voltage issues across systems	Art. 48(1)–(4)	Does the case arrangement establish clear coordination procedures for solving congestion and voltage issues, including cross-system cooperation and information exchange?
	SOC5	Grid prequalification as a coordinated network security process	Art. 49(1), 49(3)–(4), 49(6), 49(8)	Does the case arrangement define a coordinated process for grid prequalification, including assessment, communication of results, and reporting?
	SOC6	Coordination through temporary limits	Art. 50(1)–(4)	Does the case arrangement provide a clear and transparent process for setting and reviewing temporary limits in a way that protects system security while minimising unnecessary market impact?
	SOC7	Preservation of consistency of trade positions	Art. 51(1)–(3)	Does the case arrangement ensure that activation and other local service actions are coordinated so that consistency of trade positions is maintained?
	SOC8	Coordination-related data exchange between system operators	Art. 52(1), 52(3), 52(7)–(10)	Does the case arrangement ensure that system operators exchange the necessary data to support coordinated system operation?

3.4.5. Scoring approach

The scoring system need to distinguish clearly between different assessment outcomes. The scoring criteria are presented in Table 3.3.

Table 3.3: Scoring criteria for indicator assessment

Score	Description
3	Clearly aligned. The indicator is explicitly and sufficiently addressed in public documentation. The relevant arrangement is formalised, operational, and well documented.
2	Partially aligned. The indicator is partly addressed, but important elements are missing, unclear, or not yet fully implemented.
1	Not aligned. An arrangement exists, but it substantively diverges from the direction of the NCDR requirement.
0	Confirmed absence. The arrangement relevant to the indicator is confirmed to be absent, only planned, or deliberately not included.
NA	Insufficient evidence. Public evidence is not sufficient to assess the indicator reliably. This does not imply absence.

The distinction between a score of 0 and NA is methodologically important. A score of 0 is assigned only when the available documents provide sufficient basis to conclude that an arrangement is absent. For example, this may apply when regulatory reports and market documentation describe the relevant market function but confirm that a specific mechanism is not included, only planned, or replaced by another design choice. By contrast, NA is assigned when the public documentation does not provide enough information to make a reliable judgement. This may occur when a market function is managed through internal processes or when relevant documents are not publicly available.

The scores provide a structured basis for cross-case comparison. However, they should be interpreted as qualitative judgements supported by documentary evidence, not as quantitative measurements. The evidence and reasoning behind each score are presented in the case assessments in Chapter 5.

This chapter has developed the analytical basis for the case assessment. It first explained how NCDR requirements were extracted and organised into requirement categories. It then showed how selected parts of these requirements were translated into assessment subcategories, indicators, and scoring criteria. The resulting assessment framework provides the basis for comparing national flexibility market arrangements. The next two chapters explain how this framework is applied through the case study methodology.

4

Case study methodology

This chapter explains the methodology used for the comparative case assessment. It first presents the case study design and the selection of France and the Netherlands. It explains why these two cases were selected as a most-different case design within the European local flexibility market landscape. The chapter then describes the document analysis, including document collection and indicator assessment. Finally, it explains how semi-structured expert interviews were used to validate and refine the document-based assessment. Together, these methods provide the basis for applying the assessment framework developed in Chapter 3.

4.1. Case study design and selection

In this thesis, the country cases are selected according to the principles of a multiple-case study design. In such a design, cases are not chosen to be statistically representative but to serve an analytical purpose (Yin, 2018). The aim is to select cases that can illuminate the research questions and provide sufficient empirical material for applying the assessment framework. Since this thesis examines how the same NCDR requirements interact with different local flexibility market arrangements, the selected cases are expected to yield contrasting results because they represent different market architectures. At the same time, the cases need to be operational, publicly documented, and legally relevant to the NCDR. These considerations guided the selection process.

4.1.1. European LFM landscape

Local flexibility markets are developing unevenly across Europe. An increasing number of countries have introduced market-based mechanisms to procure flexibility for distribution grid management. However, these initiatives vary in maturity and geographic coverage. This variation is important for case selection because the NCDR-aligned assessment framework requires cases that are sufficiently operational and well-documented. Figure 4.1 positions the selected cases within the broader European LFM landscape. The map distinguishes four levels of market maturity: business-as-usual, emerging market, pilot, and no identified LFM. An additional overlay indicates whether a country hosts one or multiple identified LFM initiatives.

The classification distinguishes four levels of LFMs maturity. The **business-as-usual** category refers to countries where market-based procurement of local flexibility services is a routine part of system operations and is supported by a national-level regulatory framework (Chondrogiannis et al., 2022). The **emerging market** category refers to countries with active LFM operations, but where procurement is still limited in scale, fragmented across regions or actors, or not yet fully embedded in a stable national framework (European Commission and VITO, 2025). The **pilot** category includes countries where LFM initiatives are still experimental, initial project, or limited in duration (Eurelectric, 2025b; European Commission and VITO, 2025). The category **no identified LFM** refers to countries for which no local flexibility market initiatives were found in the reviewed sources.

France, the Netherlands, and the United Kingdom are classified as business-as-usual. In these countries, DSO procurement of local flexibility has become a routine part of procurement practices. France focuses on Enedis local service tenders, while the Netherlands employs GOPACS as a common congestion management mechanism involving Dutch grid operators. The United Kingdom also has mature local flexibility markets but follows a separate regulatory trajectory outside the EU.

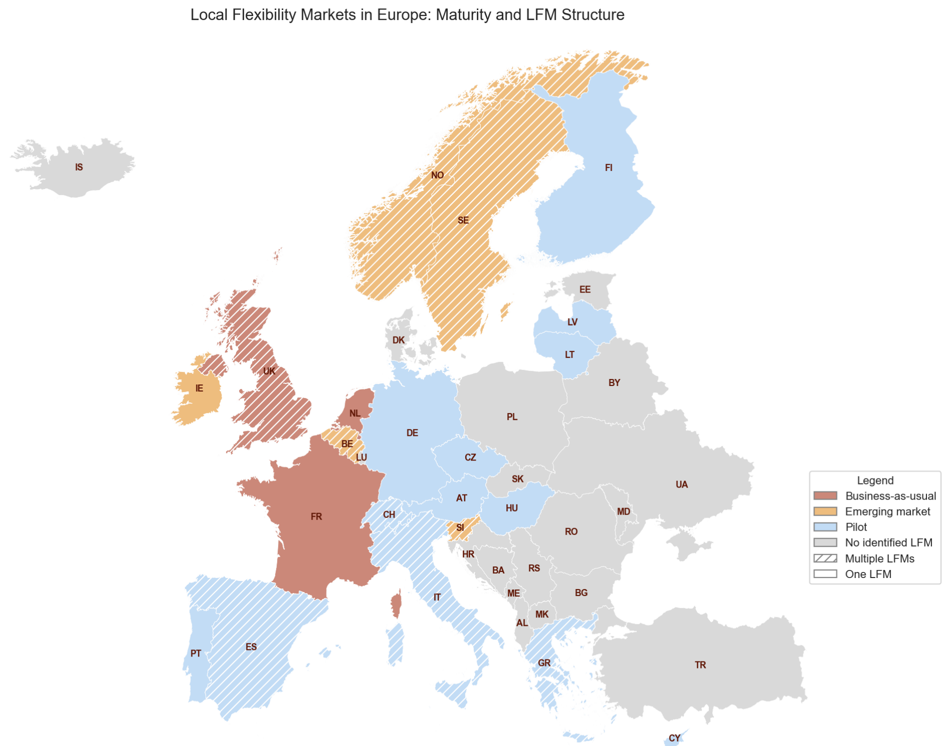

Figure 4.1: Local Flexibility Markets in Europe: Maturity and LFMs Structure. (based on Chondrogiannis et al., 2022; Eurelectric, 2025b; European Commission and VITO, 2025)

Several countries are classified as emerging markets. These countries exhibit active live LFM activity, but their arrangements remain less institutionalised than the established business-as-usual cases. In the Nordic region, Sweden hosts several regional flexibility markets, such as Effekthandel Väst in the Gothenburg area and E.ON's markets across multiple DSO grid areas. However, these initiatives operate independently and have yet to form a unified national framework (Nordic Energy Research, 2025). Norway's Euroflex initiative, which builds on the earlier NorFlex pilot, brings together several large DSOs on the NODES platform, but key design issues, including baseline calculation, coordination, and value stacking, are still being tested (Nordic Energy Research, 2025). In Belgium, Fluvius began procuring flexibility through NODES in 2024, but this activity is limited to the Flemish region, while other parts of the country remain at an earlier stage (European Commission and VITO, 2025; NODES, 2025). Slovenia and Ireland also demonstrate live market development. Elektro Ljubljana has initiated flexibility procurement, but the broader national framework for DSO flexibility procurement is still evolving (Balkan Green Energy News, 2023). ESB Networks launched a demand flexibility product with regulatory approval to procure up to 500 MW, but the process remains recent and in its early stages (ESB Networks, 2025). Overall, these cases demonstrate that LFM activity is expanding beyond pilot phases, but they also show that live market activity does not necessarily indicate full institutional maturity.

The remaining countries with identified LFM activity are classified as pilots. These include, among others, Germany, Italy, Spain, Denmark, and Finland. In these countries, local flexibility procurement is still mainly tested through pilot projects, regulatory sandboxes, or early-stage market trials. Denmark and Finland illustrate the diversity within this category. Denmark has shifted its focus from market-based local flexibility towards structural tools such as conditional connections and time-differentiated tariffs, after earlier pilots showed that LFMs can be complex and difficult to scale (Nordic Energy Research, 2025). Finland currently has no market-based flexibility services available for DSOs, although a first live pilot marketplace is expected to launch in winter 2025 (Nordic Energy Research, 2025).

Overall, the European landscape shows that LFMs are becoming increasingly prevalent, though they have not yet been uniformly institutionalised. This uneven development provides the empirical basis for the case selection described in the following subsection.

4.1.2. Case selection criteria

The case selection was guided by two sequential filtering criteria.

The first criterion is about the legal relevance of the NCDR. The selected cases should be countries where the NCDR will be directly applicable following its adoption. This excludes the United Kingdom. Although the UK has some of the most mature local flexibility markets in Europe, it is no longer an EU Member State, and its regulatory development is no longer directly influenced by EU network codes.

The second criterion relates to the analytical requirements of the research design. The assessment framework consists of 21 indicators, each requiring observable market features as the basis for evaluation. Consequently, the framework is best suited to existing and operational market arrangements. Emerging and pilot markets are also relevant to the NCDR, but they present a limitation for this thesis. In markets that are still developing, many indicators would likely be assessed as either not yet present or still under development. This would highlight implementation gaps but would reveal less about the design choices and institutional trade-offs already made in existing flexibility markets. The influence of the NCDR on less mature markets remains an important research question. In such countries, the NCDR may function primarily as a framework for market creation rather than market adaptation. By contrast, business-as-usual markets have already developed concrete arrangements for procurement, settlement, market coordination, and system operator coordination. These arrangements provide a stronger basis for assessing how existing national designs align with, diverge from, or may need to adapt to the NCDR.

After applying both criteria, two countries, France and the Netherlands, were selected for the case study. Both are EU Member States where the NCDR will be directly applicable, and both have operational LFM arrangements with sufficient maturity and publicly available documentation to support a structured NCDR-aligned assessment. Additionally, both have been in operation for more than five years (Chondrogiannis et al., 2022), providing observable market performance and existing issues. The impact of the NCDR will also be discussed in terms of whether it will help improve the current situation.

4.1.3. Most-different case design

The selection of France and the Netherlands is not only the result of the filtering process. It is also analytically valuable because the two cases represent contrasting market architectures. This combination of cases follows a theoretical replication logic, in which cases are selected because they are expected to produce contrasting results (Yin, 2018). The aim is to examine how the same NCDR requirements interact with different national designs.

France represents a DSO-led tender model. Enedis manages its own procurement process, directly overseeing tender publication, bid collection, selection, activation, and settlement. This model focuses on longer-term planning and uses semi-annual tenders and multi-year framework contracts. Flexibility delivery is measured using explicit baseline methods defined within the contract.

Table 4.1: Key architectural differences between the French and Dutch flexibility market arrangements

Dimension	France	Netherlands
Market platform type	Standalone marketplace (Enedis Marché de Flexibilités Locales)	Market intermediary (GOPACS redispatch linked to existing electricity markets)
Procurement time horizon	Long-term (semi-annual tenders and multi-year contracts)	Short-term (intraday congestion management)
DSO structure	One dominant DSO (Enedis, ~95% of the distribution network)	Multiple DSOs (Liander, Stedin, Enexis, and others)
System operator role	Local flexibility procurement mainly organised by Enedis, with RTE operating separate transmission-level arrangements	Joint TSO–DSO congestion management, with both TenneT and DSOs procuring flexibility through GOPACS
Primary flexibility service	Distribution-level congestion management (mainly MV networks)	Congestion management across transmission and distribution networks

The Netherlands exemplifies a more market-embedded model. GOPACS does not function as a standalone local flexibility marketplace. Instead, it links grid operators' congestion management requirements to bids submitted on existing intraday trading platforms. Redispatch is thus integrated into the intraday market via a counter-bid mechanism, and flexibility is quantified through accepted market positions.

Table 4.1 summarises the key architectural differences between the two cases. This contrast is directly relevant to the NCDR assessment framework. It allows the analysis to examine how NCDR requirements on procurement, market coordination, baseline methodology, and TSO–DSO coordination apply to different market architectures.

4.2. Document analysis

Document analysis is the primary empirical method of this thesis. Each country case is assessed through a systematic review of publicly available documents, using the NCDR market requirement assessment framework developed in Chapter 3. This method is suitable for the research because the assessment focuses on formal market arrangements, regulatory rules, platform procedures, and documented coordination mechanisms.

4.2.1. Document collection

Documents were collected for each case across several categories, including regulatory codes, regulator decisions, platform documentation, tender and contract documents, institutional reports, and academic literature. EU-level documents, including the draft NCDR text, ACER explanatory materials, and institutional reports, were used as common reference documents for both cases.

The document search started from the official market or platform websites in each case. For France, this mainly included the Enedis flexibility platform and related tender documents. For the Netherlands, it mainly involved GOPACS documentation and congestion management information. These websites were reviewed to identify documents relevant to the assessment indicators.

Regulatory documents were collected to understand the broader national arrangement. In the French case, documents from the CRE were reviewed, especially reports and decisions related to smart grids, flexibility, and distribution network regulation. In the Dutch case, ACM code decisions, the *Netcode elektriciteit*, and relevant publications from TSO and DSOs were examined. Search terms such as *flexibility*, *congestion management*, *local services*, *redispatch*, and *coordination* were used on official websites and search engines to identify additional relevant documents.

Table 4.2: Overview of main documents analysed per case

ID	Document	Type	Primary relevance
France			
FR-1	Enedis local flexibility tender, contract, Q&A, and results documents (Enedis, 2025a; Enedis, n.d. Enedis, 2025b; Enedis, 2026; Enedis, 2024)	Tender and contract documents	PM1; PM3–PM4; MC1–MC4; BM1–BM5; SOC5–SOC8
FR-2	CRE reports on flexibility, smart grids, and network regulation (Commission de Régulation de l'Énergie [CRE], 2025)	Regulator report	PM1–PM3; MC2; BM4; SOC1–SOC2; SOC4; SOC8
FR-3	Enedis governance and consultation documents (Enedis, 2025c; Enedis, 2021)	DSO governance and consultation documents	PM1–PM2; PM4; BM2; SOC3–SOC4
FR-4	RTE–Enedis coordination, technical publications, and flexibility platform pilot documents (Arnaud et al., 2017; Réseau de Transport d'Électricité [RTE], 2024; EPEX SPOT, 2026)	Coordination and technical documents	MC3; SOC1; SOC3–SOC4; SOC6
Netherlands			
NL-1	*Netcode elektriciteit*, ACM guidance, and congestion management code decisions (Autoriteit Consument & Markt, n.d.-b; Autoriteit Consument & Markt, n.d.-a; Autoriteit Consument & Markt, 2022; Autoriteit Consument & Markt, 2025)	Regulatory code and decisions	PM1–PM3; MC2; SOC1–SOC2
NL-2	GOPACS product, platform, FAQ, and participant documentation (GOPACS, n.d.-j; GOPACS, n.d.-i; GOPACS, n.d.-a; GOPACS, n.d.-l; GOPACS, n.d.-g; GOPACS, n.d.-b; GOPACS, n.d.; GOPACS, n.d.-c; GOPACS, n.d.-k)	Platform product documentation	PM1; PM3–PM4; MC1–MC4; BM1; BM3–BM5; SOC1; SOC3–SOC7
NL-3	GOPACS technical documentation, market data, algorithm, counter-bid, and effectivity information (GOPACS, n.d.-e; GOPACS, 2025; GOPACS, n.d.-h; GOPACS, n.d.-d; GOPACS, n.d.-f)	Platform technical and data documentation	PM3–PM4; MC3–MC4; SOC4; SOC6–SOC8
NL-4	TenneT direct channel strategy, and forecast documents (TenneT, 2024; TenneT, 2023; TenneT, 2021)	TSO product and forecast documentation	PM1; PM3–PM4; BM1–BM5; SOC2
NL-5	Dutch congestion management background and academic literature (Rabobank, 2024; Kok et al., 2022; van der Holst et al., 2026; EPEX SPOT, 2023)	Academic and institutional literature	PM2–PM3; MC1–MC2; SOC3
NL-6	Alliander & Enexis congestion management (Eurelectric, 2025a;Enexis Netbeheer, n.d.)	DSO congestion management information	PM1–PM2; BM1; BM5; SOC2–SOC3
Shared EU-level documents			
EU-1	Network Code on Demand Response, Annex 1 (ACER, 2025a)	Draft EU network code	All indicators
EU-2	ACER explanatory notes and webinar materials (ACER, 2025b;ACER, 2025c)	Regulatory context	All indicators
EU-3	Flexibility market report (European Commission and VITO, 2025; Chondrogiannis et al., 2022; Eurelectric, 2025b; DSO Entity, 2026)	Institutional report	All indicators

The two cases differ in the types of documents that provide the main empirical evidence. This reflects their distinct institutional designs. In France, the core evidence is derived from Enedis tender and contract documents, especially the *Modèle de contrat*, and from CRE reports on smart grids and flexibility. In the Netherlands, the core evidence comes from the *Netcode elektriciteit*, ACM code decisions, GOPACS platform documentation, and additional information from TSO and DSOs websites. Regarding system operator coordination, French evidence was less directly available in market documents, so academic papers and institutional reports were also used to identify relevant developments. In the Dutch case, coordination is more directly embedded in GOPACS and national congestion management arrangements.

Documents in French and Dutch were reviewed with translation support as needed. Key terms and important provisions were checked against the original language to minimize the risk of misinterpretation. Only publicly available documents were used in the analysis.

Table 4.2 provides an overview of the main documents analysed for each case. It lists the documents that provided the primary evidence for the indicator assessments in Chapter 5.

4.2.2. Analytical process

The analysis followed a directed content analysis approach (Hsieh and Shannon, 2005). The coding categories were derived deductively from the NCDR assessment framework.This approach is appropriate because the aim is is to assess how existing arrangements relate to a predefined set of NCDR derived requirements.

For each case, the documents were first screened against the four assessment subcategories. This step identified which documents contained relevant evidence for each dimension. The documents were then analysed at the indicator level. For each of the 22 indicators, the corresponding assessment question from Table 3.2 was applied to the available evidence. Based on the relevant documentary evidence from the identified documents, a qualitative alignment score is assigned according to the scoring criteria in Section 3.4.5. The same indicators and assessment questions were applied to both cases to support cross-case comparison.

4.3. Interview evidence

Semi-structured interviews were used as a supplementary research method. The primary empirical foundation of this thesis remains the document analysis described in Section 4.2. However, for some indicators, documentary evidence was incomplete, ambiguous, or insufficient to assess practical implementation. Semi-structured interviewing combines a predefined interview guide with opportunities for follow-up questions and exploration of emerging topics during the discussion (DeJonckheere and Vaughn, 2019). This approach was considered suitable because the study investigates complex market arrangements and implementation practices that cannot be fully captured through public documents alone. The interview guide ensured consistency across interviews while allowing participants to clarify documentary findings, share practical experiences, and identify implementation challenges relevant to the assessment framework.

4.3.1. Role of interviews

The interviews served three specific functions. First, they helped complete the indicator assessment where public documents did not provide sufficient information. For some indicators, relevant information was not directly available from public sources, either because it was managed through internal procedures or because the documentation was not publicly accessible. Therefore, expert interviews helped to fill these evidence gaps.

Second, the interviews helped validate the interpretation of regulatory and platform documents. Such documents can be ambiguous, and their practical meaning may differ from their formal wording. For example, a contractual clause on baseline validation may appear comprehensive in the text, but its operational application may be more limited. Interviews with relevant experts provided a check to ensure that the document-based assessment accurately reflected how the arrangements function in practice.

Table 4.3: Use of document analysis and interview evidence by indicator

Indicator	France		Netherlands	
	Document analysis	Interview evidence	Document analysis	Interview evidence
PM1	✓		✓	✓
PM2	✓		✓	
PM3	✓		✓	
PM4	✓		✓	✓
MC1	✓		✓	✓
MC2	✓	✓	✓	✓
MC3	✓		✓	✓
MC4	✓	✓	✓	✓
BM1	✓	✓	✓	✓
BM2	✓		✓	✓
BM3	✓		✓	✓
BM4	✓		✓	✓
BM5	✓	✓	✓	✓
SOC1	✓	✓	✓	✓
SOC2	✓	✓	✓	✓
SOC3	✓	✓	✓	✓
SOC4	✓	✓	✓	✓
SOC5	✓		✓	✓
SOC6	✓		✓	✓
SOC7	✓		✓	✓
SOC8	✓	✓	✓	✓

Third, the interviews provided insights into implementation realities that are only partially documented in public sources. These include practical participation experiences and implementation barriers related to flexibility procurement. These insights helped contextualise the indicator assessment findings and identify practical market issues.

Table 4.3 illustrates how document analysis and interview evidence were utilised across the assessment indicators. Document analysis was conducted for all indicators and remains the primary empirical basis of the case assessment. Interview evidence was added selectively to serve the three functions mentioned above. Interview findings were used to support, nuance, or challenge the document-based assessment. Where interview evidence adds to or qualifies the documentary findings, this is explicitly stated in the case assessments in Chapter 5.

4.3.2. Selection of interviewees

Interviewees were selected purposively. The aim was to collect targeted expert perspectives to address particular evidence gaps identified in the document analysis, rather than to obtain a statistically representative sample of all actors involved in LFMs. Each interviewee was chosen because their professional experience aligned with one or more areas where public documents were incomplete, ambiguous, or insufficient for assessing practical implementation.

The selected interviewees represented diverse stakeholder perspectives. For the Dutch case, interviews were conducted with the congestion service provider and TSO involved in congestion management and flexible market design. These interviews offered insights from both the service provider and system operator viewpoints regarding congestion management products, market coordination, baselines, and implementation barriers. In the French case, an academic expert with experience in distribution network planning and collaborative R&D projects with DSO was interviewed to provide expert insight into flexibility arrangements and implementation challenges. Additionally, an external expert interview was conducted for cross-case validation and broader reflection on NCDR implementation. Table 4.4 summarises the role of each interview in relation to the case assessment. The listed indicators show where the interview evidence was expected to be most relevant.

Table 4.4: Overview of interviewee selection

Case	Interviewee perspective	Selection reason	Evidence focus	Use in assessment
France	Academic expert with DSO R&D collaboration	Selected to provide expert knowledge on French distribution network planning and flexibility arrangements.	Market coordination; TSO–DSO coordination.	France (MC2; MC4; SOC1–SOC4; SOC8)
Netherlands	CSP / service provider	Selected to provide a service provider perspective on GOPACS participation and the practical use of congestion management products.	Market coordination; baseline methodology; TSO–DSO coordination.	Netherlands (MC2–MC4; BM1–BM5; SOC2; SOC7)
Netherlands	TSO / system operator	Selected to provide a system operator perspective on Dutch congestion management and ongoing implementation under the NCDR.	Market coordination; baseline methodology; TSO–DSO coordination.	Netherlands (PM1; MC1–MC4; BM1–BM3; SOC1; SOC3–SOC8)
Cross-case	Independent consultant	Selected to provide insights on baseline methodology, cross-case validation, and broader interpretation of NCDR implementation.	Baseline methodology.	France (BM1; BM5); Netherlands (BM1; BM2; BM5)

4.3.3. Design of interview questions

The interview questions were designed based on the assessment framework and the evidence gaps identified during the document analysis. Reflecting the three functions described in Section 4.3.1 and following the preliminary document-based interpretations, indicators with unclear evidence, ambiguous interpretations, or limited information on practical implementation were identified and used to define the main topics for the interview guides.

The interview guides were not identical for all interviewees. Instead, each guide was tailored to the interviewee's expertise and actor perspective. For the Dutch case, questions for market participants focused on practical participation in LFMs, multi-market participation, delivery verification, and market barriers. Questions for system operator experts concentrated more on product coordination, baseline setting, TSO–DSO coordination, and future developments. For the French case, questions were adapted to the expert's knowledge of flexibility in distribution network planning and Enedis R&D activities.

This design ensured that all interviews followed a consistent analytical logic while allowing each interview to focus on areas where the interviewee could provide the most relevant evidence. The complete set of interview guides and questions is provided in Appendix B.

4.3.4. Format and use of evidence

The interviews were conducted as semi-structured expert interviews of approximately 30 to 45 minutes. Each interview followed a predefined interview guide, but follow-up questions were asked when clarification was needed or when relevant topics emerged during the discussion. Interviewees received information about the research topic and interview focus in advance. Informed consent was obtained from all interviewees.

The interviews were conducted online in English. With the interviewees' consent, the sessions were recorded and automatically transcribed. The transcripts were then reviewed manually. This was necessary because the automatic transcripts were sometimes fragmented or unclear. Relevant parts of the transcripts were checked against the recording where needed.

The interview material was analysed manually by topic. The analysis focused on statements that were relevant to the assessment indicators, case interpretation, or market development barriers. Relevant extracts were grouped according to the main themes of the interview guide and the assessment framework, such as procurement, market coordination, baseline methodology, TSO–DSO coordination, and practical implementation barriers. This allowed the interview evidence to be linked to the document-based assessment in a structured way.

The score for each indicator was primarily based on document analysis. Interview evidence was used to complement this assessment when clarification, validation, or practical context was needed. In some cases, interview evidence supported the document-based interpretation. In other cases, it nuanced the interpretation or indicated that the preliminary score should be reconsidered. When interview findings are used directly for assessment in Chapter 5, a separate interview evidence paragraph is included.

For interviews with organisational representatives, the evidence is presented as the interviewees' professional perspectives rather than as official organisational positions, unless explicitly stated otherwise. This distinction is important because several interviewees discussed implementation challenges, practical experience, and possible future regulatory developments.

This chapter has explained the methodology used for the comparative case assessment. It described the case study design, the selection of France and the Netherlands, the document analysis process, and the role of expert interviews. Together, these methods provide the empirical basis for applying the assessment framework developed in Chapter 3. The next chapter presents the results of this assessment for the two selected cases.

5

Case assessment

This chapter applies the assessment framework to the French and Dutch cases. The assessment covers four subcategories: procurement mechanism, market coordination, baseline methodology, and TSO–DSO coordination. Each case starts with an overview of the national flexibility context. The indicators are then assessed using documentary evidence and, where relevant, interview evidence. The chapter ends with a cross-case comparison of the two cases. This comparison identifies similarities and differences in their alignment with the NCDR-related requirements and provides the empirical basis for the discussion in Chapter 6.

5.1. France

France represents one of the more mature and open flexibility markets in Europe. Independent aggregators can participate across multiple markets, and France is often identified as one of the more advanced Member States for demand-side flexibility (LCP Delta and smartEn, 2026). Compared with other EU countries, France also has a relatively concentrated system operator structure. It has one TSO, RTE, and one dominant DSO, Enedis, which is responsible for more than 95% of the distribution grid. This institutional structure has supported the nationwide development of local flexibility arrangements (European Commission and VITO, 2025).

At the same time, the French flexibility ecosystem is institutionally diverse. It includes aggregator participation in wholesale and balancing markets, DSO-level flexibility procurement, network tariff reform, flexible connection arrangements, and rules-based curtailment schemes (Eurelectric, 2025b). Therefore, local flexibility market should not be regarded as the sole flexibility instrument in France. Instead, they form part of a broader set of regulatory, tariff-based, contractual, and market-based tools for managing network constraints.

Market-based local flexibility procurement exists at both TSO and DSO levels. At the transmission level, RTE has initiated experimental flexibility tenders to manage network congestion. In 2021, RTE conducted a survey to identify candidate zones where flexibility could serve as an alternative to grid reinforcement, and later selected the Perquie zone in the Landes for its first experimental tender. This TSO-level initiative remains in the pilot phase, with no activation volumes recorded to date (RTE, n.d.). At the distribution level, Enedis has developed local flexibility tenders for congestion management and voltage control in specific opportunity zones. The first call for local flexibility services was issued in 2020 (Enedis, n.d.). Although DSO procurement is now considered standard practice, the contracted volume remains limited, with 46 MW contracted in 2024 (LCP Delta and smartEn, 2026).

For Enedis, local flexibility is not organised through one single mechanism. Instead, it forms part of a wider toolbox for distribution network management. Four approaches are particularly relevant. First, the ReFlex scheme represents a rules-based approach, where Enedis connects more generation capacity than traditional network design would allow and relies on curtailment when transformer limits are reached. Second, network tariffs provide time-of-use signals to shift consumption, with TURPE 7 introducing new incentives such as solar off-peak periods. Third, smart connection or flexible connection agreements allow renewable generation to connect faster by accepting certain curtailment conditions. Fourth, Enedis uses market-based local service tenders when flexibility can be more cost-effective than conventional network reinforcement (Chondrogiannis et al., 2022).

This broader context is important for interpreting the French case. The existence of local flexibility tenders does not mean that market-based procurement is the dominant flexibility tool in France. Enedis local tender is part of a wider flexibility strategy. However, in the following assessment, the focus is placed on Enedis local service tenders, because they are the French arrangement most directly related to the NCDR requirements on market-based procurement of local services. Other instruments, such as ReFlex, TURPE 7, and flexible connection agreements, are used as contextual evidence to explain the broader French flexibility arrangements.

5.1.1. Procurement mechanism

The French procurement mechanism demonstrates a strong alignment with the NCDR requirements. Enedis has established a formal, well-documented, tender-based system for procuring local flexibility services, supported by recurring tenders, detailed contractual rules, and regulatory oversight by the CRE. The procurement process is also integrated with network planning decisions through an ex-ante economic assessment to determine whether flexibility offers a cost-effective alternative to reinforcement. Operational responsibilities and procedures are clearly defined throughout the service lifecycle. Certain limitations raise concerns regarding market accessibility.

Table 5.1: Assessment of procurement mechanism indicators in the French case

No.	Indicator	Score
Procurement mechanism		
PM1	Existence of a formal market-based procurement framework	**3**
PM2	Ex-ante assessment and justification of procurement need	**3**
PM3	Quality, fairness, and openness of procurement rules	**2**
PM4	Institutional and operational design of procurement	**3**

PM1. **Assessment: Clearly aligned.**

Document analysis: The French case has a formal and well-documented market-based procurement arrangement for local flexibility services at the DSO level. Since 2020, Enedis has organised local flexibility tenders, with regular calls for local flexibility services within defined opportunity zones. The procurement process is supported by detailed tender and contract documents, which outline the contractual rules for service provision, activation, baseline methodologies, settlement, and operational responsibilities (Enedis, n.d.). This approach is also institutionally embedded. Reports from the Commission de Régulation de l'Énergie (CRE) discuss the development of local flexibility procurement and the role of Enedis tenders within the French flexibility landscape (Commission de Régulation de l'Énergie [CRE], 2025). Furthermore, Enedis describes local flexibility as an integral part of its distribution network management strategy, identifying flexibility opportunities when they offer a cost-effective alternative to conventional grid reinforcement (Enedis, 2025c; Chondrogiannis et al., 2022).

PM2. **Assessment: Clearly aligned.**

Document analysis: The French arrangement includes a documented ex-ante assessment process before local flexibility is procured. Enedis' flexibility procurement is linked to the identification of network constraints and the assessment of whether flexibility can provide a cost-effective alternative to conventional network reinforcement (DSO Entity, 2026). A key component of this process is the CritFlex methodology. According to CRE, CritFlex is used to determine Enedis' willingness to pay for flexibility by considering avoided or deferred reinforcement costs, additional network losses, and residual non-quality costs (Commission de Régulation de l'Énergie [CRE], 2025). The ex-ante assessment process is also embedded at the regulatory level. CRE monitors the application of CritFlex through the TURPE 7 incentive regulation and requires Enedis to launch tenders with capacity reservation when flexibility can defer or replace network investment (Commission de Régulation de l'Énergie [CRE], 2025). Furthermore, Enedis has publicly documented its willingness-to-pay approach in stakeholder consultations related to the ReFlex project (Enedis, 2021). These arrangements demonstrate that flexibility procurement is preceded by a structured assessment of network needs and economic efficiency.

PM3. **Assessment: Partially aligned.**

Document analysis: The French procurement process demonstrates a relatively high level of transparency and procedural fairness. Enedis publicly publishes tender documentation. Information on flexibility opportunities is also made available through the Enedis local flexibility platform, enabling potential providers to determine whether their assets are located within eligible procurement zones. Tender outcomes, including unsuccessful procurement rounds, are publicly disclosed, and procurement rules are regularly discussed with stakeholders through consultation processes (Enedis, n.d.).The arrangement is also broadly non-discriminatory and technology-neutral. It permits the participation of consumption, generation, storage, and mixed assets in its tender documentation (Enedis, 2025b). Furthermore, participation in other flexibility mechanisms is permitted (Enedis, 2025b). However, practical barriers to market access remain. Independent aggregators must establish the necessary BRP arrangements at the site level, creating additional administrative and contractual requirements that may be more burdensome for smaller market participants (Chondrogiannis et al., 2022). In addition, Enedis does not disclose its reserve price prior to tender submission, which may create information asymmetries between the procuring system operator and potential service providers (Enedis, 2025b). Finally, despite the formal openness of the procurement rules, participation remains concentrated among a small number of providers, and several recent tenders have received limited or no valid offers (Commission de Régulation de l'Énergie [CRE], 2025; Enedis, 2026).

PM4. **Assessment: Clearly aligned.**

Document analysis: The French local flexibility arrangement includes clearly defined institutional responsibilities, operational processes, and supporting systems for procurement. The *Modèle de contrat* specifies the roles of participants throughout the procurement and delivery process. Enedis is responsible for identifying flexibility needs, launching tenders, activating services, and performing settlement, while FSPs are responsible for managing flexibility portfolios and delivering contracted services. Asset owner authorisation and BRP involvement are also formally integrated through dedicated contractual arrangements. Operational procedures are defined across the full service lifecycle. The contract establishes standardised processes for activation, delivery verification, and settlement. It also defines communication channels for activation requests and data provision during the procurement procedure. The Service Observability clause creates a contractual basis for future near real-time data exchange between Enedis and FSPs (Enedis, 2021).

5.1.2. Market coordination

The French arrangement demonstrates a moderate level of market coordination. This subcategory evaluates how the French local flexibility arrangement interacts with other electricity markets and whether coordination measures exist to support efficient participation across multiple services. While the arrangement includes mechanisms for coordination with balancing markets and allows participation across various flexibility services, several aspects of cross-market coordination remain under development. In particular, coordination between local flexibility and alternative connection arrangements, as well as more integrated approaches to information sharing and market coordination, have yet to be fully established.

Table 5.2: Assessment of market coordination indicators in the French case

No.	Indicator	Score
Market coordination		
MC1	Coordination between local procurement and other electricity markets	**2**
MC2	Coordination between flexible connection agreements and local service markets	**1**
MC3	Cross-market participation arrangements	**2**
MC4	Protection against overlap and inconsistent positions	**2**

MC1. Assessment: Partially aligned.

Document analysis: The French local flexibility arrangements define several interaction mechanisms between local flexibility procurement and other electricity markets, particularly the balancing market. Public tender documentation establishes priority rules for situations in which local flexibility services and balancing services are activated simultaneously, while contractual arrangements provide BRP balance-correction procedures to ensure that flexibility activations are reflected in settlement processes (Enedis, 2025b; Enedis, 2025a). Energy products in Enedis LFM are defined to be procured once congestion occurs in the day-ahead or near real-time (DSO Entity, 2026). However, the contract contains no explicit provisions describing how local flexibility procurement relates to day-ahead or intraday market participation. The interaction between local flexibility procurement and wholesale markets is less clearly defined.

MC2. Assessment: Not aligned.

Document analysis: Flexible connection agreements in the French context are implemented through flexible connection offers (ORA-MP). The CRE reports that ORA-MP has been increasingly utilised, with 15 renewable parks connected under this arrangement in 2024 compared with five in 2023 (Commission de Régulation de l'Énergie [CRE], 2025). Public tender documentation confirms that sites subject to an alternative connection offer may participate in Enedis local flexibility tenders, provided they comply with the relevant connection, operational, and grid-access conditions (Enedis, 2024). This establishes compatibility between ORA-MP and local flexibility tenders. However, it does not define a substantive coordination mechanism between the two arrangements. The *Modèle de contrat V7* does not specify how flexible connection agreement curtailment should interact with local flexibility tender activation for the same asset (Enedis, 2025a).

Interview evidence: The academic expert interview supports this interpretation. The interviewee described flexible connection agreements and local flexibility tenders as two distinct mechanisms with different triggers. A flexible connection agreement, described as a smart connection in the interview, is negotiated at the connection stage as an alternative to a standard connection, whereas local flexibility tenders address existing network constraints after connection. The interviewee confirmed that smart connection is implemented for producers and may later be extended to storage assets but did not identify a formal operational coordination mechanism between the two flexibility approaches.

MC3. Assessment: Partially aligned.

Document analysis: The French arrangement explicitly permits participation across multiple flexibility mechanisms. Assets participating in Enedis local flexibility tenders are also allowed to contribute to other mechanisms, including RTE's balancing mechanism and other capacity-reservation arrangements (Enedis, 2025a). This principle is further confirmed in Enedis' tender Q&A documents, which state that participation in multiple mechanisms is permitted if undertaken by the same flexibility service provider (Enedis, 2025b). The arrangement also includes operational provisions supporting cross-market participation, which reduce the operational and financial risks associated with participation across multiple markets (Enedis, 2025b). However, the

French arrangement does not implement the more advanced coordination mechanisms required by the NCDR. Market participants wishing to participate in both local flexibility and balancing markets must submit bids through separate platforms. No mechanism exists for bid forwarding between Enedis and RTE, and no common information platform is currently used to coordinate participation across markets. Recent initiatives, such as the Portail Flexibilité pilot project, indicate progress in this direction, but these developments remain at the pilot stage and are not yet part of the operational arrangement (EPEX SPOT, 2026).

MC4. **Assessment: Partially aligned.**

Document analysis: The French arrangement includes several rules to reduce the risk of double selection, double activation, and inconsistent participation across flexibility mechanisms. The *Modèle de contrat V7* states that a site cannot be declared by different legal entities across the local flexibility market, RTE's balancing mechanism, system services, capacity reservation contracts, and other flexibility schemes (Enedis, 2025a). The Enedis tender Q&A also confirms that participation in several mechanisms is possible only if it is done by the same service provider, who remains responsible for delivering the local flexibility service (Enedis, 2025b). The Q&A also refers to priority rules for cases where local flexibility and the balancing mechanism are activated at the same time for the same asset (Enedis, 2025b). This provides a procedure for managing conflicting activations, although the detailed priority rules are defined mainly through RTE's market rules. However, these safeguards are mainly contractual and procedural. They do not show a fully integrated cross-market coordination platform.

Interview evidence: The academic expert interview supports this assessment. The interviewee explained that the participation restriction is linked to system security. If the same capacity is committed to several services and is not available when needed, this can create a risk for system stability. This confirms that the French rules are designed to reduce double commitment and non-delivery risk. However, this does not indicate a cross-market coordination process.

5.1.3. Baseline methodology

The French arrangement demonstrates a relatively advanced approach to baseline methodologies and verification processes. This subcategory assesses how baseline methods are defined, validated, and supported by the necessary governance and data arrangements. The French arrangement includes a comprehensive set of baseline methodologies, detailed validation procedures, and well-defined data requirements. However, several institutional elements required by the NCDR, such as national-level governance and stakeholder involvement in baseline method development, remain only partially developed.

Table 5.3: Assessment of baseline methodology indicators in the French case

No.	Indicator	Score
Baseline methodology		
BM1	Existence of a formal baseline methodology	**2**
BM2	Clarity of baseline institutional responsibilities	**2**
BM3	Existence of a clear baseline validation process	**3**
BM4	Data requirements and data sharing	**2**
BM5	Quality of baseline methods	**2**

BM1. **Assessment: Partially aligned.**

Document analysis: The French arrangement includes a formal and explicit baseline methodology for local flexibility services. The *Modèle de contrat* establishes rules for defining, calculating, validating, and applying baselines across different asset types, including consumption, generation, and mixed sites. Multiple baseline methodologies are available, including pre-activation reference methods, forecast-based methods, and historical data approaches (Enedis, 2025a). The arrangement also includes some coordination with other flexibility mechanisms. For example, Enedis may recognise baseline approval already completed under RTE's balancing mechanism, which reduces duplication for participating resources but does not imply one common Enedis–RTE baseline methodology (Enedis, 2025a). Therefore, the baseline methodology is defined within the Enedis local flexibility mechanism. It is not presented as a common national methodology jointly developed by system operators and formally approved at national level. It does not fully meet the NCDR expectation of a national baseline methodology.

Interview evidence: The independent consultant interview supports this interpretation. The interviewee confirms the baseline methodologies are more explicitly defined and subject to greater scrutiny in France. Flexibility providers must clarify which baseline method they use and how they check its accuracy. This confirms that France has a more formalised baseline arrangment. However, the gap between the current methodology and NCDR requirements still exists.

BM2. **Assessment: Partially aligned.**

Document analysis: The French arrangement clearly defines responsibilities for implementing baseline methods. The *Modèle de contrat* specifies the roles of Enedis and FSPs in baseline selection, validation, and performance monitoring. FSPs are responsible for selecting suitable baseline methods for their sites and providing the required information; Enedis is responsible for checking the selected method, validating its performance, and applying the related monitoring and penalty rules (Enedis, 2025a). However, the arrangement is less clear on the development and proposal of baseline methods. Public documents do not show a formal process through which relevant stakeholders can propose new baselining methods. Consultation processes exist, but they are not presented as a structured baseline method proposal process in the national terms and conditions (Enedis, 2021). The documents also do not clearly define the respective roles of Enedis, RTE, market participants, and the regulator in developing or updating baseline methods.

BM3. **Assessment: Clearly aligned**

Document analysis: The French arrangement includes a clearly defined process for baseline validation. It establishes comprehensive procedures for baseline development. Baseline methodologies requiring certification must be approved by Enedis before use, while validated methods are subject to continuous monitoring through periodic accuracy assessments. Additionally, the delivery of activated flexibility services is verified against the applicable reference curve, providing a further check on the practical application of the baseline methodology during service delivery. The arrangement also grants clear authority for accessing and using the data required for validation. Enedis utilises metering data collected through its distribution network infrastructure to calculate reference curves, verify service delivery, and assess baseline accuracy. Customer agreements explicitly authorise the collection and use of metering data for service validation and settlement purposes. Furthermore, certain baseline certifications obtained under RTE's balancing mechanism can be recognised within the local flexibility arrangement, reducing duplication and supporting consistency across flexibility services (Enedis, 2025a).

BM4. **Assessment: Partially aligned**

Document analysis: The French arrangement clearly specifies the data requirements necessary for baseline implementation and validation. It defines the metering data used for baseline calculation and service verification, with communicating meters operated by Enedis serving as the primary data source. The arrangement also specifies data granularity requirements. Sites with subscribed power up to 36 kVA are measured at 15 minute intervals, while larger sites are measured at 5 minute intervals. In addition, the Service Observability provisions establish requirements for higher frequency telemetry data should this functionality be activated in the future. It further establishes a legal basis for sharing baseline data. Customer agreements authorise Enedis to collect, use, and share relevant technical and contractual data with authorised stakeholders. The arrangement also supports limited data exchange between Enedis and RTE through the recognition of baseline certifications obtained under the balancing mechanism

(Enedis, 2025a). However, data sharing remains primarily centred on Enedis as the main data holder and coordinator, which does not yet provide a more extensive data sharing environment. CRE identifies network observability and data exchange capabilities as areas requiring further development to support more dynamic system operation (Commission de Régulation de l'Énergie [CRE], 2025).

BM5. **Assessment: Partially aligned**

Document analysis: The French arrangement incorporates several features that enhance the quality of baseline methodologies. It provides detailed definitions of the baseline methods used for different asset types, thereby supporting transparency and recalculability, as the baseline calculation process can be reproduced and verified by market participants. The methodology also includes measures to improve accuracy and prevent abusive behaviour. Historical reference periods exclude activation periods associated with local flexibility, balancing services, and other flexibility mechanisms, reducing the risk of artificially inflated baselines. Additionally, baseline methods are checked monthly against an absolute error threshold of 15%. During activation, delivery is also monitored against contractual thresholds, and significant deviations may trigger penalties (Enedis, 2025a). The methodology further supports the use of existing data where possible. Baseline calculations are based on data from Enedis operated communicating meters, and certain baseline certifications obtained through RTE's balancing mechanism can be recognised within the local flexibility arrangement (Enedis, 2025a). However, not all quality principles are explicitly addressed. Unbiasedness is not defined as a formal design objective, although some methods include procedures that may reduce systematic estimation error. Rebound effects are not explicitly considered in the baseline methodology.

Interview evidence: The independent consultant interview adds an important evidence. The interviewee identified rebound effects as one of the most difficult unresolved issues in baseline design. The interviewee explained that rebound depends on technology, location, and timing, and that no country has solved it in a concrete operational way. It is also noted that France may consider rebound only to a very limited extent. This supports the assessment that the French arrangement is partially aligned, but still has a significant gap on rebound effects.

5.1.4. TSO-DSO coordination

The French case demonstrates partial alignment with the system operator coordination requirements. RTE and Enedis have established several coordination mechanisms among various flexibility tools. However, the French arrangement is still evolving. Public documents reveal practical coordination between RTE and Enedis, but several NCDR requirements are not yet fully evident in the current local flexibility arrangement. This is particularly true for observability, grid prequalification, temporary limits, trade-position consistency, and structured data exchange. Therefore, the following indicators assess France as a case with clear coordination foundations but also significant implementation gaps.

Table 5.4: Assessment of TSO–DSO coordination indicators in the French case

No.	Indicator	Score
TSO-DSO coordination		
SOC1	Existence of a formal national coordination framework	**1**
SOC2	Establishment and maintenance of DSO observability areas	**0**
SOC3	Coordinated forecasting and detection of local system issues	**2**
SOC4	Coordination for solving congestion and voltage issues across systems	**2**
SOC5	Grid prequalification as a coordinated network security process	**NA**
SOC6	Coordination through temporary limits	**NA**
SOC7	Preservation of consistency of trade positions	**1**
SOC8	Coordination-related data exchange between system operators	**2**

SOC1. **Assessment: Not aligned.**

Document analysis: The French case shows substantial coordination between RTE and Enedis, but it lacks the formal national coordination arrangement required by the NCDR. RTE and Enedis have worked on TSO–DSO coordination through a joint project since 2014, which addresses issues such as voltage management, reactive power, distributed generation, and information exchange at the TSO–DSO interface (Arnaud et al., 2017). Recent documents indicate ongoing progress. The CRE highlights improvements in coordination between RTE and Enedis for the joint management of flexibilities but emphasizes that this coordination must continue and accelerate (Commission de Régulation de l'Énergie [CRE], 2025). This suggests that the current arrangement remains incomplete. The Portail Flexibilité pilot, supported by EPEX SPOT's Localflex platform, represents another significant step. It aims to support registration, visibility of flexibility needs, bid selection, and reporting for RTE and Enedis (EPEX SPOT, 2026). The main gap is the lack of formalisation and national coverage. Available evidence also points to bilateral coordination between RTE and Enedis and experimental platform development, but does not encompass all relevant system operators, including local DSOs. The rencent DSO report indicate that the RTE-Enedis optimised coordination process will be fully deployed by 2028 (DSO Entity, 2026).

Interview evidence: The expert interview supports this assessment. The interviewee confirmed that RTE and Enedis exchange information and are increasingly working on coordination. However, the interviewee described the current coordination as limited, not automated, and often case-specific. For example, activation coordination may still rely on direct communication between RTE and Enedis in certain cases. The interviewee also stated that a coordinated TSO–DSO platform for flexibility would be needed in the future, but that its implementation would take time. This suggests that coordination is recognised as necessary, but has not yet been formalised as a national coordination arrangement.

SOC2. **Assessment: Confirmed absent.**

Document analysis: The French case demonstrates increasing attention to grid observability, and the real-time observability of local services is under development (DSO Entity, 2026). CRE identifies grid observability as essential for dynamic grid management and references ongoing investments such as DERMS, NIO, and improved substation monitoring (Commission de Régulation de l'Énergie [CRE], 2025). These initiatives aim to improve network visibility and data exchange. The main challenge remains the integration of data flows into system operators' information systems to fully utilise them. Additionally, these projects are expected to be potentially operational by 2027 (Commission de Régulation de l'Énergie [CRE], 2025). Therefore, the process for defining DSO observability areas is not yet in place.

Interview evidence: The expert interview supports this assessment. The interviewee confirmed that observability and data exchange are active issues in France, particularly as distributed resources gain importance. However, the interview did not reveal the existence of a formal observability process. Instead, the interviewee described the current TSO–DSO data exchange as limited and not automated. The interviewee also stated that data exchange protocols still need to be defined, not only between RTE and Enedis, but also with flexibility providers, aggregators, and producers. This suggests that France is still developing the data and observability basis needed for coordinated flexibility management.

SOC3. **Assessment: Partially aligned.**

Document analysis: The French case shows coordination between RTE and Enedis for forecasting and detecting system issues, but the evidence is stronger for planning horizons than for a fully developed short-term coordinated forecasting process. The 2017 CIRED paper shows that RTE and Enedis have worked together since 2014 on operational planning and coordination (Arnaud et al., 2017). ReFlex and the S3REnR process also support identifying areas where forecasted renewable injection may exceed firm grid capacity (Enedis, 2025c). The recent DSO report describes a TSO–DSO coordination process in which RTE informs Enedis of potential congestion, Enedis proposes possible solutions along with their costs, RTE conducts simulations, and Enedis activates the most cost-efficient solution (DSO Entity, 2026). This demonstrates that short-term forecasting and coordination are implemented in practice. However, the current process is still not fully aligned with the NCDR expectation of a structured coordinated forecasting process among system operators. The DSO Entity report describes the RTE–Enedis optimised coordination process as a multi-year project to be fully deployed by 2028. It also identifies future needs such as more granular real-time grid monitoring for forecasting, preventing, and solving congestion (DSO Entity, 2026). This confirms that current operational forecasting capability still has gaps.

Interview evidence: The expert interview supports this assessment. The interview highlighted short-term forecasting as a new challenge. For example, storage connected to distribution networks may participate in transmission-level services while also creating constraints in the distribution grid. This issue is still under study, suggesting that some cross-system effects are not yet addressed through established operational forecasting practices.

SOC4. **Assessment: Partially aligned.**

Document analysis: The French case includes several mechanisms for addressing congestion and voltage issues across systems. RTE and Enedis have worked on TSO–DSO coordination for several years (Arnaud et al., 2017). RTE also uses NAZA, an adaptive zone automation system, to manage network constraints through automated curtailment. CRE reports that NAZA deployment is accelerating under TURPE 7 (Réseau de Transport d'Électricité [RTE], 2024; Commission de Régulation de l'Énergie [CRE], 2025). At the distribution level, Enedis uses ReFlex, a rules-based curtailment system linked to the S3REnR process and coordinated with RTE (Enedis, 2025c). The DSO report provides further evidence of operational coordination. RTE identifies potential congestion issues, Enedis proposes possible solutions along with their associated costs, RTE evaluates these options and establishes operational limits at the TSO–DSO interface, and Enedis implements the most cost-effective solution (DSO Entity, 2026). This shows that cross-system issue resolution exists in practice and includes both technical and economic coordination. However, the evidence also indicates that this coordination is still developing. CRE characterises the broader use of local flexibility as mixed and notes that contracted and activated volumes for local congestion management remain low (Commission de Régulation de l'Énergie [CRE], 2025). The DSO Entity report also states that the optimised RTE–Enedis coordination process is expected to be fully deployed by 2028, with operational limits, data exchange, and ICT still under development (DSO Entity, 2026).

Interview evidence: The expert interview supports this assessment. The interviewee confirmed that RTE and Enedis exchange information, but described the current coordination as not fully automated. Coordination often follows a request and response pattern, where RTE identifies a constraint and the DSO responds. It is also noted that activation coordination can still rely on direct communication in specific cases. This confirms that practical coordination exists, but still depends partly on informal operational interaction.

SOC5. Assessment: Insufficient evidence.

Document analysis: The French case involves several qualification steps for Enedis local flexibility tenders. The local flexibility contract requires a Customer Agreement authorising Enedis to access the relevant sites from the asset owner. It also requires BRP consent for injection and mixed sites where the flexibility provider is not the BRP. In addition, Enedis certifies certain baseline methods and verifies the quality of the certified methods during implementation (Enedis, 2025a). These elements show that Enedis assesses whether a site and its flexibility service can participate in the local flexibility arrangement. However, the available public documents do not provide sufficient evidence to assess the grid prequalification required by the NCDR. They do not indicate whether a formal grid security assessment is conducted by all relevant system operators.

SOC6. Assessment: Insufficient evidence.

Document analysis: The Enedis local flexibility arrangement outlines how Enedis activates local flexibility services and how flexibility providers report product unavailability (Enedis, 2025a). Some operational coordination between RTE and Enedis also exists within the French system (Arnaud et al., 2017). However, the available public documents do not provide sufficient evidence to determine whether a temporary limits process is in place. The local flexibility contract does not describe a separate procedure by which Enedis or impacted system operators establish temporary network limits for flexibility providers before activation. Additionally, the evidence regarding RTE–Enedis coordination is general and does not specify temporary limits for local flexibility services.

SOC7. Assessment: Not aligned.

Document analysis: The French case includes mechanisms to address the effect of local flexibility activation on BRPs and suppliers. The Enedis local flexibility contract includes BRP balance correction and supplier compensation arrangements. Flexibility activations are treated as instructed imbalances when calculating the final BRP position (Enedis, 2025a; Chondrogiannis et al., 2022). This shows that the French arrangement recognises that LEM activation can affect BRPs. However, this mechanism operates post-activation. It corrects the settlement impact, but it does not maintain trade-position consistency before gate closure. Public documents do not show an opposite direction activation by Enedis or RTE to restore the BRP position within the relevant market window. The currently low volume of local flexibility may explain why Enedis and RTE do not yet anticipate significant system imbalances resulting from LEM activations (Chondrogiannis et al., 2022).

SOC8. Assessment: Partially aligned.

Document analysis: The French case shows that data exchange between RTE and Enedis already exists. The Enedis local flexibility contract allows Enedis to use and transmit technical and contractual data to relevant stakeholders, such as RTE. It also references data exchanged with RTE for the operational implementation of the balancing mechanism (Enedis, 2025a). However, the current data exchange does not yet constitute a structured coordination process covering all NCDR-related requirements. The available documents do not clearly define the scope or review process for coordinating data exchange. They also do not clarify how this data exchange supports grid prequalification, temporary limits, or assessments by impacted system operators. The New Operational Interface (NIO) project represents a significant development. CRE states that RTE and Enedis are collaborating on the NIO project to modernise grid management processes between them, from three-year advance planning to real-time operations.

The project aims to coordinate constraint management, leverage distribution grid resources, and balance operations in alignment with grid constraints. However, these new processes are expected to be implemented gradually between 2027 and 2029, so NIO is not yet an operational arrangement (Commission de Régulation de l'Énergie [CRE], 2025).

Interview evidence: The expert interview supports this assessment. The interviewee confirmed that data exchange is a critical area of development but described the current data exchange process as not fully automated. The interviewee also noted that data exchange must be defined not only between the TSO and DSO, but also with flexibility providers, aggregators, and producers. This indicates that the current arrangement is still evolving.

5.2. Netherlands

The Netherlands has one TSO, TenneT, and several DSOs, including Enexis, Liander, Stedin, Coteq, Rendo, and Westland Infra. It is often regarded as one of the more advanced European examples of market-based flexibility procurement, which is mainly interpreted in this case as redispatch. Two main redispatch approaches exist for system operators in the Netherlands. The first is GOPACS, a coordinated platform used by the TSO and DSOs. The second is Reserve Power Other Purposes (ROP), a direct TenneT redispatch channel through platform RESIN used by the TSO (TenneT, 2023). The TSO interview indicated that ROP has much higher redispatch volumes than GOPACS. However, GOPACS remains important for this thesis because it is the most visible joint TSO–DSO platform. Since 2018, approximately 1,280 MWh has been secured by DSOs through GOPACS (LCP Delta and smartEn, 2026). Therefore, GOPACS is used as the main Dutch case for assessing market-based local flexibility procurement, while RESIN/ROP is used as supplementary evidence.

GOPACS is not a standalone local flexibility marketplace. It is an add-on mechanism connected to existing electricity trading platforms, including EPEX SPOT, ETPA, and the upcoming Nord Pool (Eurelectric, 2025b). Through these platforms, market participants can offer flexible capacity for congestion management and voltage control services. GOPACS enables Dutch grid operators to use flexible capacity when there is a temporary constraint at a specific grid location. By linking flexibility activation to the timing and location of congestion, GOPACS aims to ensure that flexibility is used efficiently and transparently, without creating new constraints elsewhere in the grid (GOPACS, n.d.).

GOPACS currently includes several congestion management products with different degrees of contractual and market-based design. These include capacity limitation contracts (CLC), capacity steering contracts (CSC), Time Duration Transport Right (TDTR), mandatory bidding contracts, and redispatch (GOPACS, n.d.). CLC-T/CSC-T refers to capacity limitation or steering within fixed time windows, whereas CLC-A/CSC-A allows the grid operator to activate capacity limitation or steering when congestion is anticipated, typically on a day-ahead basis. TDTR is better understood as a flexible connection arrangement for TenneT-connected users. In contrast, redispatch and mandatory bidding contracts are more directly related to market-based congestion management.

RESIN/ROP applies mainly to larger connected parties with a connection capacity greater than 60 MW that submit redispatch bids directly to TenneT. These bids are used to resolve transport problems and are selected where they are effective in reducing power flows over overloaded grid elements, at the lowest possible cost (TenneT, 2024).

For the NCDR assessment, this distinction is important. CLC-T/CSC-T and CLC-A/CSC-A resemble bilateral or rule-based contractual instruments, because capacity limits, activation conditions, and compensation are largely predefined. TDTR is closer to a flexible connection arrangement. Therefore, the most relevant Dutch products for evaluating market-based procurement are redispatch and the market delivery component of mandatory bidding contracts. Redispatch is the clearest market-based approach, because activation is based on submitted bids. This includes redispatch through GOPACS and direct redispatch channels such as ROP. Mandatory bidding contracts are more hybrid. The obligation to participate is contractual, but the delivery of flexibility still occurs through redispatch bids. This makes the Dutch case analytically interesting because it combines voluntary market participation, direct TSO redispatch channels, and contractual mechanisms designed to ensure sufficient flexibility availability.

5.2.1. Procurement mechanism

The Dutch case is strongly aligned with the procurement mechanism requirements. Evidence shows that market-based procurement is both legally grounded and operationally implemented. Procurement is linked to identified congestion management needs and conducted through market-based processes with publicly available operational information. The Dutch model differs from a standalone platform because it is embedded within existing electricity trading structures. However, this does not reduce its alignment with the NCDR direction. It demonstrates that market-based procurement can be organised through a market intermediary arrangement. Table 5.5 displays the scores for the procurement mechanism indicator assessment.

Table 5.5: Assessment of procurement mechanism indicators in the Dutch case

No.	Indicator	Score
Procurement mechanism		
PM1	Existence of a formal market-based procurement framework	**3**
PM2	Ex-ante assessment and justification of procurement need	**2**
PM3	Quality, fairness, and openness of procurement rules	**3**
PM4	Institutional and operational design of procurement	**3**

PM1. **Assessment: Clearly aligned.**

Document analysis: Redispatch is recognised as one of the congestion management services available to grid operators under the supervision of ACM (Autoriteit Consument & Markt, n.d.-a). This legal basis is also reflected in official Dutch documents. Article 9 of the *Netcode elektriciteit* specifies that grid operators procure congestion management services through two main products: the redispatch product in Bijlage 11 and the capacity limitation product in Bijlage 12 (Autoriteit Consument & Markt, n.d.-b). GOPACS and ROP both provide the operational platform for implementing redispatch. GOPACS connects grid operators' congestion management needs with intraday redispatch bids submitted by market participants, thereby turning the legal requirement into an active market-based process (GOPACS, n.d.-j). This logic is also reflected in mandatory bidding contracts. Enexis explains that a redispatch *biedplichtcontract*, or mandatory bidding contract, requires a market participant to submit bids when congestion management is needed, and that these bids are then used through the redispatch mechanism (Enexis Netbeheer, n.d.).

The other redispatch approach, the ROP product specification, indicates that CSPs can submit redispatch bids directly to TenneT to resolve transmission-level congestion (TenneT, 2024).

Interview evidence: The TSO interview clarifies that GOPACS should not be understood as the full Dutch redispatch arrangement. TenneT also uses other redispatch channels, including direct bids submitted to TenneT through RESIN/ROP and direct operational communication with large connection points or power plants. The ROP documents confirm that redispatch bids can be submitted directly to TenneT and selected to solve transport problems at the lowest possible cost (TenneT, 2024). This indicates that Dutch market-based redispatch is broader than GOPACS.

PM2. **Assessment: Partially aligned.**

Document analysis: The Dutch arrangement includes an ex-ante assessment step before grid operators procure or reject congestion management solutions. When physical congestion is anticipated, the grid operator must first announce the expected congestion and investigate whether congestion management can be applied in the relevant area (Rabobank, 2024; Autoriteit Consument & Markt, 2022; Autoriteit Consument & Markt, n.d.-b). However, this process is mainly congestion triggered. It does not amount to a systematic cost benefit comparison between flexibility procurement and network expansion. Recent DSO-level reporting indicates that, in the Dutch case, financial limits on flexibility expenditure may be applied instead of a full cost-benefit analysis (DSO Entity, 2026). This suggests that the Dutch arrangement has a practical decision process for applying congestion management, but not a complete economic assessment for flexibility approach.

PM3. Assessment: Clearly aligned.

Document analysis: The Dutch redispatch arrangement under GOPACS provides procurement rules that are objective, transparent, non-discriminatory, and technology-neutral. GOPACS enables market participants to submit redispatch bids through connected trading platforms, and the mechanism does not favor any specific technology type. Participation depends on whether an asset can adjust generation or consumption in response to congestion management needs. Market participants determine the size and price of their offers, supporting a technology-neutral and market-based procurement approach (GOPACS, n.d.-i; Rabobank, 2024). The arrangement treats bids non-discriminatory. Bids submitted under mandatory bidding obligations do not receive priority over voluntary bids simply because they are mandatory. GOPACS selects the combination of bids that resolves congestion at the lowest societal cost (Rabobank, 2024; GOPACS, n.d.-i). Transparency is ensured through the public availability of congestion information and historical redispatch data. GOPACS publishes redispatch market announcements and historical market activity data, making the mechanism's operation visible to market participants and external observers (GOPACS, n.d.-h). Overall, the redispatch and mandatory bidding arrangements provide clear evidence of quality, fairness, and openness in procurement rules.

ROP provides supplementary evidence for the Dutch redispatch arrangement. The ROP product specification defines the role of CSP, bid submission, activation, and settlement processes. It also states that ROP bids are selected when they effectively reduce power flows over overloaded grid elements at the lowest possible cost (TenneT, 2024). This supports the assessment that Dutch redispatch is based on clear product rules and transparent operational criteria. Larger connected parties with a connection capacity above 60 MW are required to submit redispatch bids directly to TenneT, while smaller connections can choose between GOPACS channels and TenneT channels (Autoriteit Consument & Markt, n.d.-b;TenneT, 2023). This shows that the Dutch redispatch arrangement is not organised through one single channel, but the channel rules are explicitly defined. Overall, the existence of different channels does not undermine the assessment, because the distinction between GOPACS and direct TenneT redispatch is documented and rule-based.

PM4. Assessment: Clearly aligned.

Document analysis: The Dutch redispatch arrangement is supported by well-defined actor roles, operational procedures, and IT systems. Institutional roles are distributed among several actors. ACM sets and supervises congestion management rules; grid operators identify congestion-management needs; GOPACS coordinates the redispatch process; CSPs support bidding and settlement; and connected trading platforms provide the market infrastructure. It explicitly states that GOPACS is not a trading platform itself but collaborates with trading platforms such as ETPA and EPEX SPOT to connect grid operators' flexibility needs with market bids (GOPACS, n.d.-i). The operational process is also standardised. GOPACS describes a registration and pre-qualification process in which connected parties and CSPs create accounts, register their connections, and have those connections pre-qualified by grid operators before use (GOPACS, n.d.). Once congestion management is required, grid operators place orders for flexible capacity on GOPACS, and CSPs place bids on connected energy trading platforms. This indicates that the procurement process has been translated into an executable workflow. The supporting IT systems are fully operational. GOPACS provides technical documentation for API-based processes (GOPACS, n.d.-e). Additionally, GOPACS has introduced a new algorithm that combines bids from connected trading platforms into a single virtual order book. This allows bids from different platforms, with varying volumes or durations, to be matched into a balance-neutral solution (GOPACS, 2025). Public data on redispatch announcements and historical market activity further demonstrate that the arrangement is active and data supported (GOPACS, n.d.-h).

ROP provides supplementary evidence that direct TenneT redispatch is also organised through defined procedures. The ROP product specification sets out the CSP role, bid submission, activation and settlement (TenneT, 2024). This indicates that the broader Dutch redispatch arrangement is supported by both joint TSO–DSO platform processes and direct TenneT procedures.

5.2.2. Market coordination

The Dutch case demonstrates a relatively high degree of alignment with the market coordination requirements. Its main strength is that flexibility procurement is integrated with existing electricity market processes and congestion management arrangements. This provides a basis for coordinating products, market timeframes, and market participants. At the same time, the Dutch redispatch arrangement is broader than GOPACS alone. TenneT also uses direct redispatch channels, including RESIN/ROP. The channel strategy distinguishes these approaches mainly by connection size and bidding obligation. GOPACS is used as the main case for market coordination because it is the visible joint TSO–DSO platform and is linked to existing trading platforms. Therefore, the following indicators mainly assess the GOPACS-based arrangement.

Table 5.6: Assessment of market coordination indicators in the Dutch case

No.	Indicator	Score
Market coordination		
MC1	Coordination between local procurement and other electricity markets	**3**
MC2	Coordination between flexible connection agreements and local service markets	**3**
MC3	Cross-market participation arrangements	**2**
MC4	Protection against overlap and inconsistent positions	**2**

MC1. **Assessment: Clearly aligned.**

Document analysis: The Dutch arrangement defines how local service procurement through GOPACS interacts with existing electricity market processes. Different GOPACS products operate across various market timeframes. Capacity limitation contracts address more predictable congestion before or around the day-ahead stage, while redispatch provides a short-term instrument closer to the intraday timeframe (GOPACS, n.d.-j). In GOPACS Redispatch, participants submit bids via connected platforms, such as EPEX SPOT and ETPA, and these bids include locational information and are made available to grid operators. The collaboration between EPEX SPOT and GOPACS demonstrates that redispatch utilizes the same trading infrastructure as continuous intraday trading, while serving the specific purpose of congestion management (EPEX SPOT, 2023). In addition, redispatch is designed to remain balance neutral. A local redispatch action is matched with a counter-bid outside the congested area, allowing local congestion to be resolved without disturbing the balancing market (GOPACS, n.d.-j).

Interview evidence: The TSO interview clarifies that GOPACS redispatch should not be understood as ordinary intraday trading. Although redispatch bids utilize intraday trading platforms, the redispatch process itself is a separate congestion management procedure. The interview also confirms that GOPACS is not the only redispatch channel used by TenneT. Other direct redispatch channels exist, but GOPACS remains the main platform for assessing market coordination in this case.

MC2. **Assessment: Clearly aligned.**

Document analysis: The Dutch case provides an explicit mechanism for coordinating flexible connection agreement product with market-based procurement for local service. Within the GOPACS product structure, TDTR, a flexible connection type product, and redispatch, a local procurement product, serve complementary congestion management functions across different time horizons. TDTR is designed for companies directly connected to TenneT's high-voltage grid and guarantees access to contracted transport capacity for at least 85% of the hours in a year, while allowing TenneT to impose partial limitations during the remaining hours (GOPACS, n.d.-l). Coordination between TDTR and congestion management services is addressed in the Dutch regulatory process. In the 2025 code decision, ACM confirmed that a capacity steering contracts (CSC) can be combined with a TDTR under certain conditions. ACM further stated that when a party holds both a TDTR and a capacity control contract, it must be clear at all times whether the TDTR and/or the congestion management service is being used (Autoriteit Consument & Markt, 2025). This directly mitigate the risks of double counting and uncertainty. Operationally, the Dutch arrangement also structures the coexistence of different congestion management instruments through GOPACS. Academic research on the Dutch case analyses the coordination between capacity limitation contracts and redispatch contracts within a single congestion management process (van der Holst et al., 2026). Therefore, within the assessed GOPACS arrangement, the relationship between flexible connection agreement and local service market procurement is explicitly recognised and operationally structured.

Interview evidence: The CSP interview provides additional insight into the practical role of flexible connection arrangements. The interviewee explained that TDTR and similar arrangements of flexible connection agreement are primarily valued because they enable faster grid access under constrained network conditions. In practice, these arrangements are typically accompanied by mandatory redispatch participation. Specifically, mandatory bidding contracts often accompany TDTR. This bundling establishes a direct operational link between flexible connection agreements and market-based congestion management at the contract level.

The TSO interview further clarifies how these products are coordinated in practice. The interviewees emphasised that TDTR should be distinguished from congestion management products because TDTR is a grid connection contract rather than a procured congestion product. In contrast, CSC is a day-ahead congestion management product, while redispatch is an intraday congestion management product. This distinction shows that the Dutch arrangement separates flexible connection agreements and market-based congestion products by legal nature and operational timeframe. At the same time, the interviewees explained that TDTR and CSC can be operationally adjacent because both may be relevant in the day-ahead timeframe. In such cases, TenneT must decide which instrument to activate based on cost optimisation and product-specific constraints, such as the annual limitation on TDTR activation. This confirms that coordination between flexible agreement connection and congestion management products is also considered in daily operational decision-making.

MC3. **Assessment: Partially aligned.**

Document analysis: The Dutch arrangement enables participation across platforms, and to some extent across markets, but it does not implement bid forwarding as required by the NCDR. Within GOPACS, cross-platform activation allows bids from different connected trading platforms to be combined into a single virtual order book. This increases the available flexibility pool and improves the chance of finding a cost-effective redispatch solution (GOPACS, 2025). However, this function mainly coordinates bids across trading platforms within the redispatch process, which cannot be interpreted as a full bid forwarding mechanism between different electricity markets. GOPACS also recognises that flexible capacity may be used in other electricity markets, such as FCR, aFRR, mFRR, or the imbalance market, provided that the CSP and BRP coordinate the use of capacity and prevent double use or conflicting activations (GOPACS, n.d.-g). This indicates that multi-market participation is not excluded by design. However, public documentation does not show a bid forwarding mechanism.

Interview evidence: The CSP interview supports this interpretation. The interviewee explained that flexible assets may be active in several markets, but the same capacity is not necessarily offered simultaneously in all of them. The capacity is allocated across markets according to technical constraints and commercial value. Assets already contracted for balancing services are generally excluded from mandatory redispatch participation, while only uncontracted “free volume” is made available for congestion management. This suggests that multi-market participation exists in practice, but it is managed through portfolio allocation by the service provider rather than through an integrated bid forwarding process.

The TSO interview further confirms that a more integrated architecture between intraday trading and redispatch has not been fully implemented. The interviewees distinguished between an ”elegant” design, in which one intraday bid could also be used for redispatch, and a less integrated design, in which market parties trade in the intraday market and submit separate redispatch bids when congestion is announced. They indicated that the more integrated design had been considered, but was not implemented by the connected trading platforms. This evidence supports the assessment that the Dutch arrangement enables cross-platform activation and allows cross-market participation, but lacks a clear operational bid forwarding arrangement.

MC4. **Assessment: Partially aligned.**

Document analysis: Within GOPACS-based congestion management, the Dutch arrangement includes strong safeguards against double selection. Redispatch bids are submitted through connected trading platforms, and once matched and executed, they are removed from the relevant order book. Additionally, GOPACS' cross-platform activation function combines bids from connected trading platforms into a single virtual order book. This enables coordinated bid selection across platforms and reduces the risk of double selection (GOPACS, n.d.-g). The counter-bid mechanism also helps maintain consistent market positions by ensuring that local redispatch actions remain balance neutral. However, safeguards are less explicit when the same flexible capacity is used across congestion management and other energy markets, such as balancing markets. GOPACS states that flexible capacity offered through GOPACS can often also be used in other markets, but this requires coordination with the CSP and BRP to avoid double use of capacity or conflicting activations (GOPACS, n.d.-g). Thus, cross-market participation is possible, but the prevention of double activation across market types relies primarily on operational coordination by market participants and service providers.

Interview evidence: The CSP interview confirms that protection against double use and conflicting activations is primarily achieved through portfolio management by CSPs and BRPs. According to the interviewee, capacity already committed to other services is generally not offered in redispatch markets, thereby reducing the risk of overlapping commitments. The interviewee also noted that TenneT can distinguish deviations resulting from different market activations, suggesting that conflict prevention is partly supported through settlement arrangements. However, the interview still implies that avoiding conflicts depends largely on operational management by market participants rather than on fully automated cross-market safeguards. This evidence supports the assessment that coordination mechanisms exist but are not yet fully integrated across markets.

The TSO interview adds an important nuance. The interviewees confirmed that preventing double activation is primarily the responsibility of the market party submitting the bid. They also explained that an IT-level mechanism has been conceptually developed to remove or lock a bid from the intraday market when the same flexibility is activated for congestion management. However, this mechanism has not yet been fully implemented by most connected trading platforms. Therefore, the interviewees characterized this issue as a future operational challenge rather than a fully resolved feature of the current arrangement.

5.2.3. Baseline methodology

The baseline methodology subcategory is particularly important in the Dutch context because it shows a difference between the Dutch prognosis-based design and the NCDR expectation of formal baseline rules. In GOPACS redispatch, the reference point is embedded in the participant's existing market schedule or market position. In ROP, the T-prognosis performs a similar operational role. However, these references are not the separately calculated statistical baselines. Therefore, the Dutch arrangement can be understood as using a practical nominal baseline approach (DNV, 2024). This supports activation and delivery verification, but it is not yet codified as a complete NCDR style baseline methodology.

Table 5.7: Assessment of baseline methodology indicators in the Dutch case

No.	Indicator	Score
Baseline methodology		
BM1	Existence of a formal baseline methodology	**2**
BM2	Clarity of baseline institutional responsibilities	**2**
BM3	Existence of a clear baseline validation process	**2**
BM4	Data requirements and data sharing	**2**
BM5	Quality of baseline methods	**1**

BM1. **Assessment: Partially aligned.**

Document analysis: The Dutch redispatch arrangement does not define a separate statistical baseline methodology with explicit public rules for calculating a counterfactual level of consumption or injection. Instead, it relies on schedule-based or prognosis-based reference values. In GOPACS redispatch, accepted buy and sell orders change the participant's position compared to the original schedule (GOPACS, n.d.-a). This indicates that the existing market schedule or market position serves as the practical reference point for redispatch. The DSO report also points out that the baseline for GOPACS is provided by the customers themselves, which could be classified using the declarative baseline methodology (DSO Entity, 2026).

ROP provides similar supplementary evidence. The ROP product specification states that activated power is delivered relative to the T-prognosis at the time of activation and in addition to the planned dispatch. The activated volume is then used for BRP imbalance correction (TenneT, 2024).

The TenneT forecast document further shows that forecasts are submitted one day in advance and updated during the execution day, which supports the role of prognoses as formal operational references for grid security analysis (TenneT, 2021). This suggests that the T-prognosis functions as an operational reference for activation and settlement. However, public documents do not provide a complete baseline methodology and do not clearly specify how the schedule or prognosis is validated. Based on document analysis, the Dutch case provides a practical baseline approach, but not a fully formalised NCDR baseline methodology.

Interview evidence: The CSP interview supports this interpretation. The interviewee explained that GOPACS redispatch relies on the asset's market schedule and BRP nomination as operational reference points. Day-ahead and intraday positions define the expected delivery profile, and redispatch activations modify this market position. Therefore, from the CSP perspective, a separate baseline calculation is not necessary in practice.

The independent consultant interview further supports this assessment. The interviewee explained that GOPACS does not prescribe one baseline methodology, but relies on the prognosis, E-program, or energy program submitted by the CSP. She described this as a form of "nominal baseline", because the CSP submits what it expects to generate or consume and this schedule is then used as the reference for flexibility delivery. She also noted that this is not an official term, but a useful way to classify the Dutch approach.

The TSO interview adds a connection-point perspective. The interviewees explained that participants submit a prognosis, which represents the expected withdrawal or injection before redispatch activation. When redispatch is activated, the activated volume is added to or subtracted from the prognosis to establish an activation-adjusted reference for verification. The interviewees also indicated that a national baseline methodology is being developed through the limitation concept, which will apply not only to redispatch, but also to capacity steering contracts and flexible connection arrangements. All of this demonstrates that a formal baseline methodology is currently under development.

BM2. **Assessment: Partially aligned.**

Document analysis: The Dutch redispatch arrangement establishes practical responsibilities for implementing prognosis-based reference values. A forecast/prognosis must be submitted one day in advance and updated during the execution day. Connected parties may submit forecasts themselves or outsource this task to a BRP, but they remain responsible for data quality. Grid operators then use the submitted forecasts for grid security analyses and congestion prevention (TenneT, 2021). The arrangement defines the responsibilities for submitting and using prognosis-based reference values. However, it does not clearly specify who develops, approves, or updates the baseline methods.

Interview evidence: The CSP interview supports this assessment. The interviewee explained that GOPACS redispatch relies on the asset's market schedule and BRP nomination as operational reference points.

Both TSO and independent consultant interview further clarifies the interpretation. The interviewees explained that the prognosis is submitted by the service provider, and this submitted schedule reflects what it expects to generate or consume. However, it was also noted that GOPACS does not prescribe a single baseline methodology, but allows the CSP considerable flexibility within the market schedule structure. Therefore, it does not outline a formal stakeholder process for proposing, developing, or approving baseline methods.

BM3. **Assessment: Partially aligned.**

Document analysis: The Dutch redispatch arrangement includes clear processes for validating activation and delivery, but it does not define a process for validating baseline methods. In GOPACS redispatch, activated participants are required to follow redispatch instructions, maintain reliable measurement and control, log delivered flexibility, and receive payment only after verification of delivered MWh (GOPACS, n.d.-j).

RESIN/ROP provides similar supplementary evidence. The ROP product specification states that activated power is delivered relative to the T-prognosis at the time of activation and in addition to the planned dispatch. The activated volume is then used for BRP imbalance correction (TenneT, 2024).

The TenneT forecast document also provides relevant evidence regarding data usage. It states that grid operators compare forecasted and measured values, provide quality feedback and reports, and consult individual market participants about forecast quality (TenneT, 2021). This suggests that grid operators have access to and utilize the data necessary to assess the quality of prognosis-based reference values. However, this still differs from validating a formal baseline method.

Interview evidence: The CSP interview supports this assessment. The interviewee explained that GOPACS delivery is evaluated based on the updated market position following redispatch activation. This means that validation focuses on physical delivery and consistency with the market position.

The TSO interview explained that participants submit a prognosis before activation. When redispatch is activated, the activated volume is added to or subtracted from this prognosis to establish an adjusted reference. Actual metered values can then be compared with this reference to verify delivery. However, the interviews do not indicate the existence of a formal baseline method validation process.

BM4. **Assessment: Partially aligned.**

Document analysis: Public documents define data requirements and data-sharing arrangements that partly cover minimum data inputs, granularity, and sharing arrangements. For GOPACS redispatch, the minimum data inputs are defined by the general forecast obligation. Market participants must submit forecasts one day in advance and update them during the execution day. These forecasts include expected production and consumption, encompassing both active and reactive power (TenneT, 2021). In addition, GOPACS participants are required to register on the platform, submit bids via connected trading platforms, and operate reliable near real-time measurement and control infrastructure, such as an EMS or telemetry system to support bid execution and delivery verification (GOPACS, n.d.-j). The required granularity is partly defined. Forecasts are submitted at 15-minute intervals and at the level of each individual grid connection point (TenneT, 2021). Data-sharing routes are also partially defined. Parties directly connected to TenneT submit forecasts to TenneT, while those connected to a DSO submit to the relevant operator. Submission may be outsourced to a BRP, but the connected party remains responsible for data quality. Grid operators provide feedback on forecast accuracy by comparing forecasted values with actual measurements (TenneT, 2021).

For ROP, the minimum data inputs are defined within the bid specification itself, which includes the preparation period, delivery period, direction, volume in MW, and grid location (TenneT, 2024). After activation, the delivered power is measured relative to the T-prognosis, and an updated T-prognosis must be sent to the grid operator immediately (TenneT, 2024). The required granularity is more fully specified at the product level. ROP uses 15-minute intervals as its time unit and identifies the relevant location through an EAN code (TenneT, 2024). Data sharing follows a direct bilateral route. After activation, TenneT sends a transaction message to the supplier and BRP specifying the transaction volume, price, bid reference, and the BRP imbalance correction (TenneT, 2024). However, they are documented as operational data flows, not as one integrated baseline data arrangement. They do not fully define how baseline data should be calculated, validated, shared, and used under the NCDR.

Interview evidence: The CSP interview confirms the practical data logic. The interviewee explained that verification at the TenneT level is usually supported by measurements at the grid connection or transformer level. This makes delivery verification relatively straightforward at transmission level. However, DSO-level verification may be more difficult because of the larger number of connections and less mature measurement infrastructure.

BM5. **Assessment: Not aligned.**

Document analysis: Public documents does not demonstrate that the Dutch prognosis-based reference meets the required baseline quality principles. In GOPACS redispatch, the reference is linked to the participant's original market position, and payment depends on verified delivery (GOPACS, n.d.-a; GOPACS, n.d.-j). This supports a basic level of transparency in the redispatch transaction and helps reduce manipulation risk. However, the quality of the underlying schedule or prognosis is not clearly validated as a baseline method. Recent DSO-level report also raises concerns about the low quality of customer forecasts and baseline data, which may affect flexibility activation and congestion management decisions on GOPACS(DSO Entity, 2026). This weakens the evidence for accuracy and transparency. In addition, public documents do not specify how rebound effects are assessed or managed.

ROP provides similar supplementary evidence. Activated power is delivered relative to the T-prognosis at the time of activation, and the activated volume is used for BRP imbalance correction (TenneT, 2024). Therefore, the quality of the prognosis is not fully addressed, which creates a gap with the NCDR requirements.

Interview evidence: The CSP interview supports this assessment. The interviewee explained that redispatch verification is based on the adjusted market position and measured delivery. However, rebound effects are not clearly addressed in the current commercial arrangement.

The independent consultant interview further clarifies the main gap. The interviewee described the Dutch approach as a form of ”nominal baselining”, which can reduce manipulation risk because the reference is linked to the participant's market position. However, she also identified rebound effects as one of the most difficult unresolved issues in baseline design. Rebound effects depend on technology, location, and timing, and no clear Dutch procedure was identified for addressing them.

5.2.4. TSO-DSO coordination

The Dutch case demonstrates a relatively high level of alignment with the system operator coordination requirements. However, the Dutch redispatch arrangement is broader than GOPACS alone. TenneT also employs direct redispatch channels, including RESIN/ROP. These channels are mainly TenneT-led instruments and are therefore less relevant for assessing TSO–DSO coordination. For this reason, the system operator coordination assessment focuses mainly on GOPACS.

GOPACS is the most relevant Dutch arrangement for this subcategory because it is a shared platform used by the TSO and multiple DSOs. Coordination between system operators is embedded in the national congestion management arrangement through both formal regulations and the shared GOPACS platform. This provides the Dutch case with a clear institutional and operational foundation for coordinating congestion management across network levels. At the same time, some NCDR concepts extend beyond the current public documented Dutch arrangements. Requirements related to observability areas, grid prequalification, temporary limits, and broader coordination data exchange are only partly visible in public sources.

Table 5.8: Assessment of TSO–DSO coordination indicators in the Dutch case

No.	Indicator	Score
TSO-DSO coordination		
SOC1	Existence of a formal national coordination framework	**3**
SOC2	Establishment and maintenance of DSO observability areas	**2**
SOC3	Coordinated forecasting and detection of local system issues	**3**
SOC4	Coordination for solving congestion and voltage issues across systems	**2**
SOC5	Grid prequalification as a coordinated network security process	**2**
SOC6	Coordination through temporary limits	**2**
SOC7	Preservation of consistency of trade positions	**3**
SOC8	Coordination-related data exchange between system operators	**2**

SOC1. Assessment: Clearly aligned.

Document analysis: The Dutch case has a formal national coordination framework for congestion management. At the regulatory level, ACM's 2022 code decision revised the congestion management rules in the *Netcode elektriciteit*, extending their applicability beyond transmission networks to include distribution networks (Autoriteit Consument & Markt, 2022). This establishes a common legal basis for congestion management by Dutch grid operators. At the operational level, coordination is institutionalised through GOPACS, a joint initiative of Dutch grid operators that functions as a shared platform for coordinating market-based congestion management (GOPACS, n.d.). GOPACS is described as a grid operator platform involving TenneT, Stedin, Liander, Enexis Groep, and Westland Infra, designed to resolve congestion while considering the network conditions of participating grid operators and national balance maintenance (GOPACS, n.d.). This demonstrates that TSO–DSO coordination is not only a general policy objective but is embedded in both national regulations and an operational platform.

Interview evidence: The TSO interview reinforces this assessment. The interviewees explained that GOPACS is legally structured as a foundation jointly owned by the TSO and the DSOs, with one of its purposes being to organise TSO–DSO interaction. The interview also indicated that national agreements on processes and information exchange have been developed among the main parties involved in Dutch congestion management, including the TSO, DSOs, BRPs, suppliers, closed distribution systems, and connected customers. This confirms that the Dutch arrangement has a formal national coordination basis that extends beyond individual bilateral coordination.

SOC2. Assessment: Partially aligned.

Document analysis: Public documents do not demonstrate a process in which DSOs define, maintain, and periodically reassess observability areas with relevant system operators. The closest formal requirement is that grid operators must establish data exchange agreements when a congestion area involves more than one network (Autoriteit Consument & Markt, n.d.-b). However, this does not constitute a formal, ongoing observability area process. Concurrently, DSO observability capabilities are being developed in practice. For example, Alliander has implemented an open-source digital platform for capacity management, which includes real-time substation data collection, short-term load and renewable energy forecasting, power flow analysis, state estimation, and operator support tools (Eurelectric, 2025a). This suggests that at least one major Dutch DSO has developed technical tools to support grid observability and congestion management. Additionally, the TenneT forecast document indicates that DSOs provide forecast information to TenneT, enhancing forward-looking visibility of network conditions (TenneT, 2021). Nevertheless, these developments do not amount to a national observability area arrangement.

Interview evidence: The CSP interview supports this assessment. The interviewee had more experience with TenneT congestion management than with DSO operation, and noted limited visibility into DSO-level verification and measurement infrastructure. At the same time, the interviewee identified Alliander as one of the more active DSOs in product development. This is consistent with the document evidence. DSO observability capability is currently under development but has not yet been formalised as a national observability area process.

SOC3. Assessment: Clearly aligned.

Document analysis: The Dutch case shows a coordinated process for congestion forecasting and detection. In the GOPACS arrangement, the involved DSOs and TSO use load-flow calculations together with a continuous forecasting process to identify upcoming congestion. Once congestion is identified, it is registered in GOPACS, after which the platform can be used to select and execute trades that resolve the congestion (Kok et al., 2022). GOPACS then matches buy and sell orders in a way that resolves congestion at one location without creating new constraints elsewhere in the grid, while selecting the most cost-efficient combination of orders (GOPACS, n.d.-j).

Additional evidence from Alliander indicates that DSO side forecasting and grid analysis capabilities are also under development. Alliander employs OpenSTEF for short-term load and renewable infeed forecasting, utilizing live measurements, historical data, and weather forecasts. These forecasts are integrated with the Power Grid Model, which supports power-flow analysis and state estimation before congestion (Eurelectric, 2025a). However, GOPACS primarily supports congestion registration and redispatch coordination after congestion has been identified, while the earlier forecasting processes between system operators are less clearly documented.

Interview evidence: The TSO interview offers valuable clarification. The interviewees explained that TSO–DSO forecast coordination operates outside GOPACS through bilateral information exchanges. DSOs provide forecasts for their distribution grids and submit daily prognosis updates for their connection points with the HV grid. This confirms that forecast exchange exists between system operators. However, the interviewees also noted that coordinated TSO–DSO forecasting is still in its early stages, with current efforts focused on making the process operational.

SOC4. Assessment: Partially aligned.

Document analysis: The Dutch arrangement includes mechanisms for coordinating congestion solutions across network areas. GOPACS allows market participants to use flexibility to help solve congestion and voltage issues (GOPACS, n.d.-b). For redispatch, coordination is supported by the counter-bid mechanism. A bid inside the congestion area is matched with an opposite order outside the congestion area, so that local congestion can be relieved without creating national imbalance (GOPACS, n.d.-d). GOPACS also uses an effectivity matrix. This matrix records the expected effect of a bid on the congested grid element, based on network calculations by the grid operator (GOPACS, n.d.-f). These mechanisms help ensure that selected bids are relevant for solving the identified network constraint (GOPACS, n.d.-j). However, the documents primarily demonstrate coordination within GOPACS redispatch. They offer limited evidence that cross-system congestion or voltage impacts are comprehensively managed through coordination across TSO and DSO networks.

Interview evidence: The TSO interview provides important evidence. The interviewees explained that there is a function through which a DSO can restrict the use of certain assets if they create congestion in the distribution-level system. However, the interviewees also stated that this function is not yet operational in the current process. A more immediate short-term concern is the interaction between balancing activation and local congestion. For example, TSO balancing activations could exacerbate DSO congestion if many flexible assets in the same local area are activated simultaneously. Overall, the Dutch arrangement includes clear mechanisms for coordinated redispatch, but the designed safeguard against cross-system congestion impacts is not yet operational, and coordination still relies on several parallel processes.

SOC5. **Assessment: Partially aligned.**

Document analysis: The Dutch arrangement includes a clear prequalification process at the connection level. GOPACS states that connected parties and CSPs can create an account, register their connections, and have those connections prequalified by the grid operators before they can be used for congestion management (GOPACS, n.d.). It also states that CSP recognition is nationwide and only needs to be completed once, but a separate prequalification must be completed for each connection (GOPACS, n.d.-c). The registration page further explains that asset prequalification is started by entering the EANs of the relevant assets or connections (GOPACS, n.d.-k). This indicates that prequalification includes a specific grid connection check by the relevant grid operator. However, this does not fully meet the NCDR requirements for grid prequalification, which expect a coordinated assessment by both the connecting system operator and any impacted system operators. This assessment should consider whether service delivery could create congestion, voltage issues, or other operational security risks.

Interview evidence: The TSO interview confirms this interpretation. Prequalification is conducted by the system operator to which the active customer is connected. The process is straightforward, primarily requiring the EAN code and 15-minute settlement measurements. This indicates that an operational grid prequalification process exists in the Dutch context. The interview also reveals that GOPACS serves as a central registration point. Market participants can use a single national entry point, while GOPACS manages registration on behalf of the system operators, simplifying the process for market participants. However, the interview did not indicate that impacted system operators are systematically involved in assessing grid impacts before approval.

SOC6. **Assessment: Partially aligned.**

Document analysis: GOPACS includes operational safeguards that perform a similar function to temporary limits. Before redispatch bids are selected, the effect of a bid on the congested grid element is assessed through effectivity calculations. GOPACS also matches buy and sell orders in a way that resolves congestion without creating new constraints elsewhere in the grid (GOPACS, n.d.-f; GOPACS, n.d.-j). These mechanisms help ensure that selected bids support the network constraint they are intended to solve. However, these safeguards are not the same as the formal temporary limits process required by the NCDR. Public documents do not indicate a separate procedure by which connecting and impacted system operators can establish or update temporary limits.

Interview evidence: The TSO interview provides additional relevant evidence through the concept of system operation limitations. The interviewees explained that this concept defines limits that customers must adhere to after activation. It applies across several products, including redispatch, capacity steering contracts, and TDTR. This approach aligns more closely with the NCDR concept of temporary limits than with the GOPACS effectivity mechanism alone. At the same time, the interviewees noted that the regulatory process is still ongoing, particularly concerning the payment or penalty consequences when a customer exceeds these limits. The interview also did not clearly indicate how impacted system operators can set or update such limits.

SOC7. **Assessment: Clearly aligned.**

Document analysis: The Dutch redispatch arrangement is designed to maintain consistency in trade positions. In GOPACS, a local redispatch bid is always matched with an equal and opposite counter-bid outside the congestion area. GOPACS explains that the bid and counter-bid together resolve the congestion while maintaining the national balance on the electricity grid (GOPACS, n.d.-d). Additionally, since redispatch is executed through connected intraday trading platforms, the accepted buy and sell orders are treated as normal market transactions. Their effects are reflected in the usual trading and settlement processes. The CSP manages the redispatch bid, while the BRP remains responsible for the portfolio balance. In this way, local congestion management stays aligned with market positions.

Interview evidence: The CSP interview supports this assessment. The interviewee explained that redispatch activations are reflected in updated BRP nominations and intraday market schedules. Deviations are then handled through standard imbalance settlement.

The TSO interview adds further detail. The interviewees explained that, after redispatch activation, the market party must update its schedule or nomination with the TSO. The TSO then expects the party to follow the updated schedule. If the party does not comply, the deviation is settled through imbalance penalties. This demonstrates that nomination updates serve as an operational mechanism to maintain trade-position consistency. It also clarifies that this consistency is maintained at the connection point level. A BRP initially holds a market position at the portfolio level, but this position is then allocated to connected parties and translated into a prognosis at the connection point. Redispatch delivery is compared with the prognosis at the relevant connection point. Therefore, trade-position consistency is maintained both through BRP nominations and connection point prognoses.

SOC8. **Assessment: Partially aligned.**

Document analysis: The Dutch arrangement establishes a clear data exchange rule for congestion management through GOPACS. GOPACS provides technical documentation for data exchange, including APIs for flexibility messages (GOPACS, n.d.-e). It also publishes current and historical redispatch information, such as market announcements, prices, and volumes (GOPACS, n.d.-h). This demonstrates that data exchange supports both platform operation and market transparency. However, the documents do not fully address the broader data exchange requirements of the NCDR, such as observability areas, temporary limits, or systematic coordination with impacted system operators.

Interview evidence: The TSO interview reinforces the assessment that data exchange is actively being developed in the Dutch case. The interviewees explained that some national agreements on data exchange processes have already been implemented, while others are still in progress. One example is the information flow following independent CSP activation. When a redispatch product is activated, the relevant BRPs are informed so they are aware of changes affecting their customers. Subsequently, BRPs and BSPs receive detailed information necessary for daily or monthly processes, such as forecasting, billing, and others. This is managed through a national standard messaging system. The interview also reveals that data exchange between DSOs and TSO exists for both planning and operational coordination. DSOs provide longer-term forecasts, such as expected PV growth in their grids, and submit daily prognosis updates for their connection points with the HV grid. These exchanges assist the TSO in assessing potential congestion impacts across system levels. Therefore, the Dutch case demonstrates strong practical data exchange arrangements for congestion management and market coordination, but the evidence also indicates that not all NCDR-related data categories are fully covered.

5.3. Cross-case comparison

To facilitate cross-case comparison, Figure 5.1 summarises the indicator scores at the assessment subcategory level. The figure presents the average score for each subcategory in France and the Netherlands, revealing a clear difference in the alignment profiles of the two cases. Both France and the Netherlands have the same average score for the procurement mechanism, confirming that market-based procurement is relatively well developed in both countries. The Netherlands scores higher in market coordination and TSO–DSO coordination, reflecting the role of GOPACS and the stronger integration of congestion management with existing market and coordination arrangements. France scores slightly higher on baseline methodology, mainly because the Enedis tender arrangement defines more explicit baseline and validation procedures.

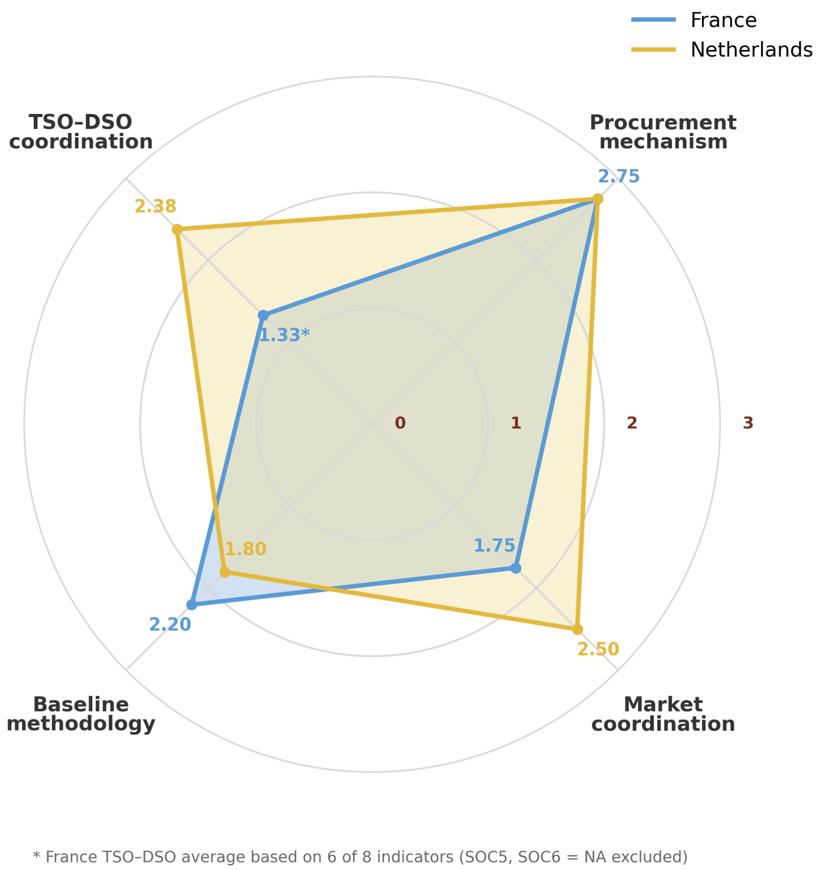

Figure 5.1: Cross-case comparison of average NCDR alignment scores by assessment subcategory

The spider chart suggests a stronger alignment profile for the Netherlands across the four selected subcategories, while also illustrating the complementary strengths of the two cases. At the same time, the figure should be interpreted with caution. The lower French score for TSO–DSO coordination partly reflects missing public evidence, as two indicators in this subcategory were assessed as NA and excluded from the average. Overall, the figure reflects the main cross-case finding: France performs better in formal tender design and baseline arrangements, while the Netherlands excels in market coordination and system operator coordination.

This chapter applied the assessment framework to the French and Dutch cases and compared their alignment with the NCDR requirements. The assessment identified both common patterns and different remaining gaps across the two national arrangements. These results provide the empirical basis for Chapter 6, which examines the barriers observed in the two cases and discusses the implications of the alignment findings for flexibility market development.

6

Discussion

Chapter 5 assessed how the French and Dutch flexibility market arrangements align with the NCDR requirements. This chapter moves from the assessment results to their broader interpretation. Section 6.1 first examines the main market development barriers observed in the two cases, organised using the barrier categories introduced in the literature review. Section 6.2 then discusses three related implications for the NCDR: the scope of NCDR harmonisation, how this scope is reflected differently in the two national arrangements, and the limits of regulatory alignment when compared with the identified barriers. Based on these findings, Section 6.3 develops practical recommendations for France, the Netherlands, and the further development and implementation of the NCDR. Finally, Sections 6.4 discuss the limitations of the research.

6.1. Barriers to market development

The case assessment shows the degree of alignment with the NCDR, but it does not capture all practical challenges to market development. This section examines the main barriers observed in the French and Dutch cases. The barrier categories follow the literature review in Section 2.2.2, while the specific barriers are identified from case evidence, including interviews and market observations. These identified barriers are compared with the assessment results from Chapter 5 in Section 6.2.3 to determine the limitations of the NCDR.

6.1.1. Regulatory barriers

Regulatory barriers concern the rules and coordination arrangements needed to support flexibility across different parts of the electricity system (Scrocca et al., 2026; Vigano et al., 2023). As flexibility resources are increasingly connected at the distribution level, effective coordination between system operators becomes particularly important. In the two cases, the main regulatory barrier involves TSO–DSO coordination, including data exchange and network observability.

Insufficient TSO--DSO coordination

This barrier refers to operational TSO–DSO coordination, data exchange, and network observability. While local flexibility can help alleviate congestion, it may also introduce new challenges if activations are not properly coordinated across different network levels.

In the French case, interview evidence suggests that TSO–DSO coordination exists, but is not yet fully automated. The academic expert explained that RTE and Enedis exchange information, but the process remains largely case-specific. RTE may identify a constraint and request that Enedis respect certain limits, while Enedis responds based on its knowledge of the distribution network. The same interview also emphasised data challenges, including confidentiality, data format, and interoperability issues.

In the Dutch case, several practical barriers remain in platform coordination. The TSO interview explained that GOPACS includes a function allowing DSOs to restrict the use of certain assets if activation would cause local congestion. However, this function has been developed but is not yet operational in the current process. The CSP interview also discussed the difference in observability between TSOs and DSOs. Assets connected to TenneT are typically linked to larger grid nodes with better measurement capabilities, whereas assets connected to DSOs are more difficult to monitor.

This barrier is becoming increasingly important because flexibility resources are more frequently connected at the distribution level, potentially creating cross-system coordination challenges. The independent consultant interview also noted that system operator coordination is a complex aspect of regulation. Therefore, TSO–DSO coordination remains a key regulatory barrier identified in 2.2.2.

6.1.2. Technical barriers

Technical barriers relate to the practical requirements for measuring and verifying flexibility delivery (Scrocca et al., 2026; Vigano et al., 2023). Reliable market operation depends on whether delivered flexibility can be identified accurately and whether its effects on the electricity system can be understood. In the two cases, the main technical barrier concerns baseline calculation issues.

Baseline calculation issues

This barrier refers to baseline quality and rebound effects. A flexibility market needs a clear reference point to measure whether flexibility has been delivered. It also needs rules for what happens after activation, especially when demand reduction or load shifting creates a rebound effect later.

In the Dutch case, one concern is the quality of customer forecasts and baseline data. If the reference point is inaccurate, flexibility activation may be measured incorrectly. It can also affect congestion management decisions, because system operators may not have a reliable view of the flexibility that is actually available or delivered.

The more general issue in both cases is the rebound effect. France has more formal baseline methods, while the Netherlands uses a more prognosis-based logic. However, neither case provides a complete operational solution for rebound effects. The indenpendent consultant interview identified rebound as one of the most difficult baseline issues. Rebound depends on the technology, the location, and the timing of the response. For example, an EV may reduce charging in one location and increase charging later in another location. This can create new local effects that are difficult to include in a simple baseline rule.

Overall, baseline and rebound are technical barriers to market development, as listed in Section 2.2.2. The problem is not only the existence of a baseline method. The deeper issue is whether the reference point is accurate, trusted, and able to deal with rebound effects.

6.1.3. Economic barriers

Economic barriers relate to whether participation in local flexibility markets provides a sufficiently clear and attractive business case (Scrocca et al., 2026; Vigano et al., 2023). Even where formal market access exists, uncertain revenues and limited predictability can reduce the willingness of market participants to invest in and provide flexibility. In the two cases, this issue is mainly reflected in revenue uncertainty.

Revenue uncertainty

This barrier is uncertain revenue and unclear risk allocation. It specifically refers to the economic factors limiting participation. Flexibility providers require predictable revenues to justify their investments and operational efforts. Similarly, system operators need assurance that flexibility will be available when required. When these conditions are not met, scaling flexibility as a market-based solution remains challenging.

In the French case, this barrier primarily arises from the comparison between flexibility procurement and grid reinforcement. The academic expert explained that flexibility creates uncertainty for DSOs due to its availability. In contrast, grid reinforcement offers a more certain network solution. If the need is not sufficiently strong, or if the availability of flexibility is highly uncertain, DSOs may still prefer to invest in grid reinforcement instead of supporting the flexibility market.

In the Dutch case, the incentive problem is more apparent from the perspective of market participants. The CSP interview indicated that redispatch is not always commercially attractive, especially because it does not offer capacity remuneration. Consequently, participation may be driven more by mandatory bidding obligations than by a voluntary business case. The TSO interview also noted that market participants need to be able to generate revenue from congestion management. However, congestion activations remain difficult to predict, and current operational volumes may be too low to justify investment. This creates uncertainty for market participants who are expected to prepare for a larger future market.

The independent consultant interview confirms that this issue is not limited to the Netherlands or France. Low revenue can restrict participation, even when providers are permitted to enter the market. This demonstrates that flexibility service providers require a clear mechanism to generate income, while system operators must have confidence that flexibility will be accessible when needed. This barrier belongs to the economic barriers discussed in Section 2.2.2.

6.1.4. Operational barriers

Operational barriers concern how effectively local flexibility markets function in practice (Scrocca et al., 2026; Vigano et al., 2023). Formal market arrangements may exist, but participation can remain limited if market activity is low or if the process is difficult for participants to understand and use. In the two cases, the main operational barriers are low market liquidity and a lack of practical know-how.

Low market liquidity

This barrier is low effective liquidity. This does not necessarily mean that flexible resources are physically absent. Rather, it means that potential flexibility is not consistently converted into active bids, successful tenders, or repeated market participation. In both cases, formal arrangements for flexibility procurement exist, but these arrangements do not always generate stable market activity.

In the French case, low liquidity is primarily evident through uneven tender outcomes and concentrated participation. As shown in Figure 6.1, Enedis local flexibility tenders have been organised regularly, but the procurement results remain unstable. The success rate declined sharply in 2025 S1, and the 2025 S2 tender round did not result in any awarded lots. This suggests that the existence of a formal tender arrangement does not automatically guarantee sufficient market response. The interview with the French academic expert noted that participation has increased compared to the early years of the scheme, but also indicated that the number of active participants remains limited. The interviewee attributed this partly to the current low demand for flexibility in France, which reduces the incentive for additional participants to enter the market.

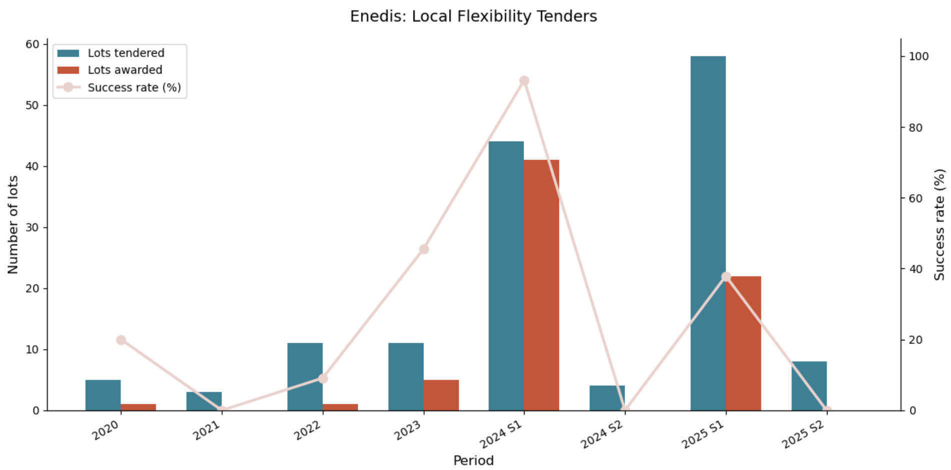

Figure 6.1: Enedis local flexibility tender outcomes in France. (based on Enedis, 2026)

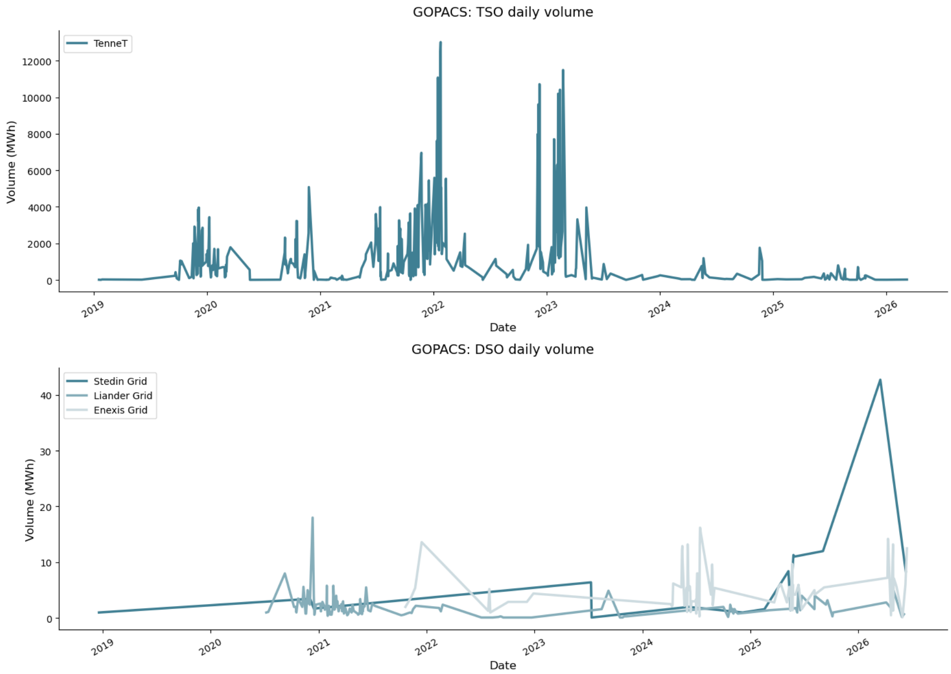

Figure 6.2: GOPACS redispatch volumes by system operator in the Netherlands. (based on GOPACS, n.d.-h)

In the Dutch case, low liquidity appears more as uneven platform activity and limited active participation. As shown in Figure 6.2, TSO-related GOPACS volumes were high around 2021–2023, but declined thereafter, while DSO-related volumes remain much smaller and more fragmented. This figure should be interpreted with caution, as GOPACS does not represent all Dutch redispatch activity. TenneT also uses direct redispatch channels such as RESIN/ROP. Nevertheless, the GOPACS data indicate that the joint TSO–DSO platform has not yet developed into a consistently liquid local flexibility market, especially on the DSO side. This interpretation is supported by the CSP interview, which described the Dutch congestion management market as having very limited liquidity and only a small share of registered CSPs being active in practice. The TSO interview adds that the issue is not only the amount of potential flexibility, but also whether market parties have access and can establish a credible business case. Current operational congestion volumes are still smaller than the expected future need, while future congestion locations and volumes remain uncertain.

Overall, low liquidity is a fundamental barrier to market formation in both cases, although it manifests differently. This barrier primarily corresponds to the operational barrier explained in Section 2.2.2. It also shows that formal market opening does not automatically create effective market participation.

Lack of know-how

This barrier refers to the practical knowledge and information needed to participate in LFMs. Service providers must understand product rules, documentation, platform requirements, bidding processes, and available market opportunities. When these elements are unclear or difficult to navigate, participation becomes more costly and time-consuming. This issue is particularly significant for small market participants and new entrants, as they have fewer resources to manage complex rules, ambiguous information, and platform challenges.

In the French case, this barrier appears mainly through tender access and information asymmetry. The Enedis local flexibility tender is well documented, but some information is not fully visible to the market, such as the reserve price used in tender evaluation. This can make it harder for providers to judge whether participation is commercially attractive.

In the Dutch case, the CSP interview described the documentation for Dutch congestion management products as confusing, with many documents and different names for similar products. The interview also pointed to platform limitations. In one example, the platform did not support some bidding conditions that were needed by the CSP to manage consecutive hours. This made it difficult for clients to meet their redispatch obligations in practice. The comparison with Nord Pool was also used to show that clear documentation, a good API, and a user-friendly interface can reduce participation costs. The TSO interview also noted that communication about congestion problems could be improved, including where congestion occurs, how it is solved, and what prices are paid. However, at the same time, the interview also showed that transparency is not simple, because there may be reasons not to disclose all congestion and price information. This makes information provision a difficult design issue rather than only a communication problem.

Therefore, these barriers affect the practical usability of local flexibility markets, which belong to the operational barrier listed in Section 2.2.2.

Overall, the two cases show several common barriers, but these barriers appear in different ways. Low market liquidity and revenue uncertainty are present in both cases. In France, low liquidity is mainly reflected in uneven tender outcomes and limited participation, while revenue uncertainty is closely related to the availability of flexibility and the comparison with grid reinforcement. In the Netherlands, low liquidity is reflected in uneven GOPACS activity and limited active participation, while revenue uncertainty is linked to unpredictable congestion activations and the lack of capacity remuneration. Lack of know-how is also observed in both cases, although it is more visible in the Dutch case through complex documentation and platform limitations. Baseline and rebound complexity affects both cases, while insufficient TSO–DSO coordination remains relevant in both France and the Netherlands. These findings show that the same broad barriers exist in both cases, but their specific form depends on the national market arrangement.

6.2. Implications for the NCDR

This section discusses three related implications for the NCDR. The first considers the scope of NCDR harmonisation based on the requirement extraction and case assessments. The second uses the cross-case comparison to examine how this scope is reflected differently in the French and Dutch market arrangements. The third combines the assessment results with the market development barriers identified in Section 6.1 to examine the limits of regulatory alignment.

6.2.1. The scope of NCDR harmonisation

This subsection draws primarily on the NCDR requirement extraction developed for SQ1, together with the case assessment results in Chapter 5, to examine what aspects of local flexibility market arrangements the NCDR seeks to harmonise. The requirement extraction defines the formal regulatory scope of the NCDR, while the case assessments show how these common requirements relate to different existing market arrangements.

The extracted requirements covers a broad range of market functions, categorised into five main areas: production design, pre-qualification, procurement, activation and settlement, and governance. However, the NCDR does not mandate a single, detailed market architecture for implementing these functions. Instead, it establishes common requirements for how these functions should be organised, coordinated, and governed.

This distinction is also evident in the case assessments. France and the Netherlands employ markedly different approaches to procuring local flexibility. France primarily relies on structured DSO tenders, whereas the Netherlands uses congestion management arrangements centred around GOPACS and redispatch. Despite these differences, both cases demonstrate a strong alignment with the NCDR procurement requirements. This suggests that diverse national market architectures can fulfill the same regulatory functions.

The remaining gaps in the two mature cases primarily involve the formalisation and coordination of existing arrangements rather than the complete absence of fundamental market functions. For example, in France, coordination between RTE and Enedis occurs in practice but has not yet been established as a comprehensive national coordination framework. In the Netherlands, prognosis-based reference points are already used in congestion management, but they have not yet been formalised as a national baseline methodology that fully complies with NCDR requirements. Similar gaps appear in areas such as joint procedures, structured data exchange, and coordination between system operators.

Taken together, the requirement extraction and the case assessment suggest that the NCDR mainly creates a common functional and governance framework rather than a single European market model. Its harmonising scope involves mandating common functions, responsibilities, procedures, and interfaces while allowing Member States to maintain diverse institutional and market architectures. Therefore, the NCDR can reduce regulatory fragmentation without necessitating that national flexibility markets converge toward a single, uniform design.

6.2.2. Different implementation pathways

This subsection draws on the cross-case assessment in Section 5.3 to examine how the same NCDR requirements translate into different implementation needs in France and the Netherlands. Both cases are relatively mature and already have operational arrangements for procuring local flexibility, but their remaining alignment gaps are located in different parts of the framework.

In France, the main adjustments relate to integration and formalisation. Although coordination between RTE and Enedis currently exists in practice, it has not yet been formalised into a national coordination arrangement covering the relevant system operators. Supporting elements, such as observability areas and structured data exchange, are either absent or still under development. Additionally, the Enedis tender mechanism remains relatively separate from balancing, wholesale markets, and flexible connection arrangements. Therefore, further alignment with the NCDR would primarily require stronger integration of existing arrangements and the establishment of more formal coordination processes.

In the Netherlands, the main adjustments involve formalising and completing existing practices. GOPACS and other congestion management arrangements already use schedules, prognoses, and market positions as practical reference points. However, these practices have not yet been developed into a national baseline methodology that fully complies with the NCDR requirements. Some coordination concepts, such as grid prequalification involving affected system operators and temporary limits, currently exist only partially or conceptually and require further development and operational implementation.

The comparison, therefore, suggests that NCDR implementation in mature markets is mainly an adaptation process. The code is applied to arrangements that have already developed along different national paths. As a result, the same European requirements can lead to different implementation priorities. France needs stronger integration across existing arrangements, while the Netherlands needs greater formalisation and completion of practices already operating in the market.

This has broader implications for European harmonisation. A common regulatory framework does not necessarily produce one common implementation pathway. Different national arrangements may achieve the same functional requirements through varied approaches. For mature markets, the NCDR seems to guide further formalisation, integration, and completion of existing arrangements rather than replacing them with a new market model. For less mature markets, the implementation process may differ. In cases where fewer market arrangements are in place, the NCDR can serve as a more robust reference for developing new rules and procedures.

6.2.3. The limits of regulatory alignment

This subsection draws on the case assessment in Chapter 5 and the barriers identified in Section 6.1. The two are compared to examine whether closing the NCDR alignment gaps would also help address the practical barriers observed in the two cases. The degree of overlap differs across the four barrier categories. Technical and regulatory barriers are closely related to the NCDR requirements, operational barriers are only partly covered, and economic barriers remain largely beyond the direct reach of regulatory alignment.

More directly within the NCDR's reach. The technical barrier related to baseline and rebound complexity is closely connected to the baseline indicators in the assessment framework. The NCDR requires formal processes for defining, calculating, and validating baselines, which relates directly to BM1 and BM2. In France, baseline methods and validation procedures are already relatively well defined within the Enedis local flexibility arrangement. In the Netherlands, congestion management already uses prognosis-based reference points, but these have not yet been formalised as a national baseline methodology. Closing these gaps would therefore strengthen the formal basis for baseline calculation and validation in both cases.

The remaining quality issues are reflected particularly in BM5. The NCDR requires baseline methods to meet principles such as accuracy, transparency, and unbiasedness, and it also requires rebound effects to be considered. These requirements directly address some of the technical concerns identified in Section 6.1. However, regulatory alignment cannot remove all technical complexity. The interviews showed that rebound effects depend on technology, location, and timing, while the NCDR does not provide a complete method for identifying or measuring them. Therefore, the code can establish the requirement, but further technical development is still needed to make it operational.

The regulatory barrier related to TSO–DSO coordination is also strongly reflected in the assessment framework. It corresponds particularly to the formal coordination framework (SOC1), DSO observability areas (SOC2), coordination across systems (SOC4), and coordination-related data exchange (SOC8). The Netherlands already has a relatively strong starting point through GOPACS and national congestion management arrangements, although some coordination processes remain incomplete or not yet fully operational. France shows larger gaps. Coordination between RTE and Enedis exists in practice, but it is not yet formalised as a comprehensive national arrangement, while observability and structured data exchange are still developing.

Therefore, in these two areas, the NCDR can directly address important regulatory gaps by requiring common methodologies, coordination processes, and data exchange arrangements.

Partly within the NCDR's reach. The operational barriers identified in Section 6.1 are only partly covered by the NCDR assessment framework. The lack of know-how is related to requirements for transparent and non-discriminatory procurement, clear operational arrangements, proportionate qualification processes, and effective information exchange. These issues are particularly reflected in PM3 and PM4. Improved alignment can therefore help reduce some of the administrative and information barriers faced by flexibility providers.

However, the case evidence shows that formal openness does not necessarily make a market easy to use. In the Netherlands, the CSP interview identified confusing documentation, different product names, and platform limitations even though the assessment showed relatively strong alignment in procurement openness and operational design. Similar issues may arise when comparable arrangements are described differently across Member States. These problems do not necessarily indicate non-compliance with the NCDR, but they can still increase the effort required to participate. While the NCDR can mandate clearer and more consistent rules, it cannot fully control the quality of national documentation, communication, or platform design.

Low market liquidity has an even weaker direct correlation with the assessment indicators. Requirements related to open procurement, market access, and simplified qualification processes may facilitate participation and thereby indirectly support liquidity. However, no indicator within the assessment framework directly measures whether a sufficient number of providers submit bids, whether activations occur regularly, or whether participants remain active over time. The cases of France and the Netherlands both demonstrate that formal market arrangements can exist even when market activity is limited or uneven.

For this reason, regulatory alignment can eliminate some operational barriers to participation, but it cannot, by itself, create a liquid market. Liquidity also depends on the number and location of available providers, the actual need for flexibility, and the attractiveness of participation.

Largely beyond the NCDR's direct reach. The clearest limitation lies in the economic barrier of revenue uncertainty. This barrier has only limited direct overlap with the assessment framework. While the NCDR can establish principles for fair and transparent procurement and remuneration, it does not determine whether participation will generate sufficient or predictable revenue.

The two cases illustrate this limitation in different ways. In France, the opportunity for repeated participation is influenced by the current level and location of demand for local flexibility. Flexibility must also compete with grid reinforcement as an alternative network solution. These conditions affect the value of flexibility but cannot be changed through NCDR alignment alone. In the Netherlands, congestion needs are stronger, but the CSP interview indicated that redispatch is not always commercially attractive, particularly without capacity remuneration. The TSO interview also emphasised uncertainty regarding future congestion volumes and locations, making it difficult for market participants to predict future revenues.

Detailed choices such as capacity remuneration, energy-only payments, activation prices, and the balance between mandatory and voluntary participation largely remain national decisions. They also depend on local network conditions and the expected value of flexibility compared to alternative solutions. Therefore, even full alignment with the NCDR would not guarantee stable activation volumes, predictable revenues, or a viable business case.

Overall, the comparison demonstrates that the closer a barrier aligns with the formal rules, methodologies, and coordination processes assessed in Chapter 5, the more directly the NCDR can address it. Regulatory barriers and much of the technical barriers fall most clearly within its reach. Operational barriers can be mitigated only partially through regulatory alignment, while economic barriers largely depend on national market choices and local system conditions. Therefore, NCDR alignment can improve conditions for market operation, but it alone cannot ensure an active and commercially viable flexibility market. The remaining barriers require complementary actions from national regulators, system operators, and market participants. These practical implications are discussed in Section 6.3.

6.3. Practical implications and recommendations

This section translates the main findings into practical recommendations for three targets: France, the Netherlands, and the further development and implementation of the NCDR. France and the Netherlands are considered separately because the case assessment identified different alignment gaps and market-development barriers in the two countries. The recommendations for each case therefore address both the remaining steps towards NCDR alignment and the barriers that cannot be resolved through regulatory alignment alone. The final subsection considers whether the findings also suggest areas where the NCDR or its implementation guidance could be improved.

6.3.1. France

In terms of NCDR alignment, the main priorities for France relate to system operator coordination and the formalisation of existing arrangements. The assessment identified significant gaps in the SOC indicators, particularly in the national coordination arrangement (SOC1), DSO observability areas (SOC2), and trade-position consistency (SOC7). Market coordination also remains incomplete, while baseline governance is still largely organised within the Enedis local flexibility arrangement. The findings suggest that further alignment could be achieved by developing the existing RTE–Enedis coordination into a more formal national framework, establishing clearer observability and data-exchange arrangements, and strengthening national-level baseline governance. Ongoing developments such as NIO and DERMS are already moving in this direction and could serve as a foundation for closing several of these gaps.

Beyond NCDR alignment, the French case suggests that developing a more active flexibility market should not be a goal by itself. Indicator PM2 already reflects this logic by requiring an ex-ante assessment of whether flexibility is a justified alternative to grid reinforcement. This is particularly relevant in France, where interview evidence suggests that current congestion pressure is still relatively limited and the power system remains supported by a large and stable nuclear generation base. The current use of longer-term flexibility tenders by RTE and Enedis may therefore remain appropriate while flexibility needs are still limited. Rather than rapidly expanding procurement, system operators should continue to evaluate where flexibility offers clear economic and operational benefits compared to reinforcement.

At the same time, the need for flexibility may increase with further electrification and the integration of renewables. France could use the current period to improve market readiness and commercial design. Existing flexibility arrangements already include several products and approaches, but participation and market activity remain limited. Where more reliable flexibility availability is expected to become necessary, regulators and system operators could review whether current contracting arrangements provide sufficient incentives for service providers. This review could include considering capacity reservation arrangements where appropriate, rather than relying only on energy-based remuneration. Such preparation would allow the market to develop in response to actual system needs while also reducing future revenue uncertainty for providers.

6.3.2. The Netherlands

In terms of NCDR alignment, the main priorities for the Netherlands are to formalise and complete arrangements that already exist in practice. The assessment reveals a strong starting point in procurement and system operator coordination, but several gaps remain. Baseline quality is the clearest issue (BM5), particularly regarding forecast quality and rebound effects. DSO observability arrangements are not yet fully formalised (SOC2), and bid forwarding between markets remains incomplete (MC3). Therefore, the findings suggest that further alignment should focus on finalising the national baseline methodology, formalising observability arrangements, and developing the remaining cross-market coordination processes.

Beyond NCDR alignment, the main challenge is the commercial viability of congestion management. Interview evidence indicates that redispatch does not provide capacity remuneration and that only a limited share of registered CSPs are active in practice. While mandatory bidding can ensure the availability of flexibility, it does not necessarily create a strong voluntary business case. The TSO interview also described this as a balance between obligations and economic incentives. This suggests that ACM and the system operators should assess whether the current remuneration structure offers sufficient incentives for sustained voluntary participation.

Practical access could also be improved alongside these economic incentives. The CSP interview identified complex documentation, different product terminology, and platform limitations as additional barriers. Improving the clarity of market information and the usability of congestion management platforms could therefore reduce participation costs. These measures primarily fall within national market implementation and would complement the NCDR alignment.

6.3.3. NCDR development and implementation

The case assessment also points to several areas where the further development and implementation of the NCDR could be improved. These recommendations are related to common requirements that may still be difficult to apply consistently in practice across both cases.

First, further guidance could be provided on addressing rebound effects. The NCDR requires that proven rebound effects be considered in baseline methodologies, but the case assessment shows that this remains challenging to operationalise. Neither case provides a complete approach, and interview evidence suggests that rebound effects vary significantly depending on technology, location, and timing. Therefore, further EU-level guidance could clarify how rebound effects should be identified and assessed, potentially through common detection principles or technology-specific approaches.

Second, greater clarity could be provided regarding the terminology used for flexibility arrangements across Member States. Related concepts appear under different national names, such as smart connection arrangements and ORA-MP in France, and TDTR and VVTR in the Netherlands. These differences do not necessarily reflect different functions, but they can make national arrangements more difficult to compare and understand for market participants operating across multiple countries. A common terminology guide or a mapping between NCDR concepts and national arrangements could reduce this complexity without requiring Member States to adopt identical product names.

6.4. Limitations

This section outlines the main limitations of the research. While these limitations do not undermine the findings, they provide important context for interpreting the results. Additionally, they highlight potential directions for future research.

6.4.1. Case selection and framework applicability

This research is based on two cases, France and the Netherlands. Both are relatively mature flexibility markets, and both are among the more advanced Member States. This selection was suitable for a most-different case design, but it also creates two limitations related to the scope of the framework.

The first limitation relates to the applicability of the assessment framework to less mature markets. In countries where flexibility markets remain mainly at the pilot or regional stage, many indicators may receive low scores or cannot yet be fully assessed because national processes and institutions have not been established. While the framework can still identify which NCDR governance requirements are missing, the results offer less insight on existing market arrangements. This reflects the purpose of the framework. It assesses alignment with the NCDR rather than the maturity or quality of the market design itself. The NCDR provides common requirements for market governance and coordination, but does not prescribe one detailed market architecture. Consequently, less mature markets must still develop products, procurement arrangements, and commercial models tailored to their own system conditions. In such cases, the framework may serve as a regulatory reference but is less suited to guiding the broader process of market development.

The second limitation concerns the exclusion of several subcategories. The assessment framework is selective, focusing on 21 indicators across four subcategories. Other NCDR-related topics, such as product design, detailed pre-qualification procedures, pricing arrangements, and market timing, are not assessed at the same level of detail. This means the framework does not cover the market design layer of the NCDR. If a market's main challenge lies in the detailed design of its products or prices, the framework would not capture it directly. However, since the NCDR does not impose strict requirements in these areas, there is no clear benchmark against which to measure any gaps. For example, the pricing requirements state that the mechanism shall allow energy-only or capacity payments, subject to an economic efficiency assessment. These are broad framing requirements. Therefore, the impact of this exclusion on the research objective is limited. This choice is also consistent with the central finding of this research, namely that the NCDR mainly harmonises governance rather than market design.

6.4.2. Timing of the NCDR

At the time of this research, the NCDR has not yet entered into force. Therefore, Chapter 5 assesses national arrangements against future regulatory requirements rather than obligations currently being enforced. This approach presents two limitations. First, the alignment scores reflect the current state of France and the Netherlands before formal NCDR implementation. National rules may still change once the NCDR comes into effect. Additionally, national interpretations and possible derogations under Article 11 may influence how the requirements are applied in practice. Second, the implications discussed in Section 6.2 are partly forward-looking. They assume that closing certain alignment gaps would help address specific market development barriers. This is a reasoned interpretation based on case evidence, but cannot yet be empirically tested. Future research conducted after the NCDR enters into force could examine how national alignment evolves and whether the anticipated market effects actually occur.

6.4.3. Evidence limitations

This research relies mainly on publicly available documents, supported by semi-structured expert interviews. This improves the traceability of the assessment, but it also means that internal procedures or ongoing developments may not always be visible.

The interview coverage is also uneven across the two cases. In France, one case-specific interview was conducted with an academic expert who also works with Enedis on R&D projects. In the Netherlands, two case-specific interviews covered the perspectives of the TSO and a CSP. One additional interview with an independent consultant provided cross-case insights, although the discussion was more detailed for the Netherlands. The Dutch case therefore has a richer interview basis. For example, the TSO interview provided information on the developing national baseline approach that was not clear from public documents. Similar details may be missing from the French assessment.

A further limitation concerns the interview design. Because the number of interviews was limited, the interview questions were adapted to the expertise of each interviewee and to the evidence gaps identified in each case. This helped obtain more relevant case-specific information, but it also reduced the comparability of the interview evidence. Different interviewees were not always asked the same questions, so some differences in the evidence may reflect the interview design rather than differences between the two cases. With a larger interview sample, a more standardised set of core questions could be used across interviewees, while stakeholder specific follow-up questions could still be included where needed.

Finally, regulator and DSO perspectives are not directly represented in both cases. This limits the interpretation of regulatory intentions and some DSO implementation practices, particularly where public documents provide only partial information.

6.4.4. Market performance data

Market performance data are used to support the identification of barriers in Section 6.1. This includes Enedis local flexibility tender outcomes for France and GOPACS redispatch volume data for the Netherlands. While these datasets are useful, they have clear limitations. The GOPACS data represent only one redispatch channel in the Netherlands. TenneT also employs direct redispatch channels, such as RESIN/ROP, and direct operational communication with large connection points. These activities are not fully captured in the publicly available GOPACS data. Therefore, GOPACS data should not be interpreted as a comprehensive measure of Dutch redispatch activity. Similarly, the Enedis tender data have limitations. They show procurement outcomes for Enedis local flexibility tenders but do not represent the entire French flexibility system. In addition, tender results reflect awarded contract lots rather than actual activation volumes. Consequently, they should not be considered a complete measure of French flexibility. For these reasons, the market performance data are used as illustrative evidence for the specific arrangements assessed in this thesis. A more thorough performance analysis would require access to non-public data on bids, prices, activations, redispatch volumes, and settlement outcomes.

6.4.5. Scoring judgement

The indicator scores presented in Chapter 5 are based on document analysis and interview evidence. However, scoring still involves a degree of judgment. Some indicators are easier to assess because the relevant requirements are clearly documented, while others are more challenging, particularly when public evidence is incomplete or when national arrangements use terminology that differs from the NCDR. To mitigate this limitation, the assessment uses a consistent scoring scale and provides explanations for the reasoning behind each score. Interview evidence is used, where possible, to validate or refine the document interpretations. Nevertheless, the scores should be understood as structured assessments based on available evidence, rather than precise measurements. Future research could strengthen the assessment by involving more researchers in the scoring process, or by validating the scores with a wider group of stakeholders.

This chapter has interpreted the case assessment beyond the indicator scores themselves. The barrier analysis showed that regulatory alignment does not remove all practical challenges to flexibility market development. The discussion further showed that the NCDR provides a common functional framework while allowing different national implementation pathways, and that its reach becomes more limited for operational and economic barriers. These findings were translated into recommendations for the two case-study countries and for the further development and implementation of the NCDR. The chapter also identified the main limitations of the research. The next chapter brings these findings together to answer the sub-questions and the main research question and to conclude the thesis.

7

Conclusion

This thesis examined what the alignment of current local flexibility market arrangements with the forthcoming EU Network Code on Demand Response (NCDR) reveals about the code's scope and limits in shaping these markets. Since the NCDR has not yet entered into force, the research focused on current regulatory and market arrangements. It combined NCDR requirement extraction, the development of an assessment framework, and comparative case assessments of France and the Netherlands. This chapter concludes the thesis by answering the three sub-questions and the main research question, followed by directions for future research.

7.1. Answering the subquestions

SQ1: What requirements related to flexibility markets are introduced by the NCDR?

The first subquestion was addressed using the requirement extraction table developed in Chapter 3 and presented in Appendix A.

The main challenge was not only to identify the relevant NCDR provisions but also to organise them in a way that reflects the structure of local flexibility markets. NCDR Annex 1 contains ten titles and fifty-eight articles. However, its legal structure does not directly correspond to the functional structure of a LFM. Requirements related to a single market function may be scattered across several titles, while some titles are only partially relevant. For this reason, analytical categories were developed before the detailed requirements extraction. The extraction identified five main categories of NCDR requirements relevant to local flexibility markets: product design, pre-qualification, procurement, activation and settlement, and governance. These were further divided into fifteen subcategories. Together, they demonstrate that NCDR encompasses more than just procurement. It also addresses the broader conditions necessary for flexibility markets to function effectively.

SQ2: How can these requirements be translated into a structured assessment framework?

The second subquestion was answered by translating selected NCDR requirements into an assessment framework shown in Table 3.2.

Not all fifteen subcategories were selected for the case assessment. The selection was based on analytical relevance, evidence availability, and the need for comparison across cases. Four assessment subcategories were selected: procurement mechanism, market coordination, baseline methodology, and TSO–DSO coordination. These subcategories capture the core elements necessary to assess how national flexibility market arrangements relate to the NCDR. Subsequently, they were developed into 21 indicators. Each indicator was linked to specific NCDR provisions and reformulated as an assessment question. Scoring approach was created to provide a structured basis for cross-case comparison. This framework established a structured link between the legal text of the NCDR and observable features of national flexibility market arrangements.

SQ3: How do selected national flexibility market arrangements align with the NCDR requirements?

The third subquestion was answered by applying the assessment framework to France and the Netherlands in Chapter 5 and interpreting the results in Chapter 6.

Both cases show relatively mature arrangements for market-based procurement of local flexibility services. In both countries, procurement mechanisms are operational, documented, and broadly aligned with the NCDR. However, the two cases show different readiness profiles. France represents a DSO-led tender model. It is strong in formal procurement design and baseline validation. Enedis local flexibility tenders are based on a structured procurement process, and define several baseline methods and validation procedures. The main gaps are related to coordination. Local flexibility, balancing, wholesale markets, and flexible connection arrangements remain relatively separate. TSO–DSO coordination also exists in practice, but it has not yet been fully formalised as a national coordination framework.

The Netherlands represents a market-embedded platform model. Congestion management is supported by national regulation and by GOPACS as a shared TSO–DSO platform. This leads to strong alignment in market coordination and several aspects of system-operator coordination. The main gap is the baseline foundation. The Dutch prognosis-based approach works in practice, but it has not yet been formalised as a national baseline methodology that fully meets the NCDR quality principles, especially on forecast quality and rebound effects.

The case assessment also showed that regulatory alignment and market development are related but not the same. Both cases face market development barriers despite their relatively high level of maturity. These barriers include low effective liquidity, revenue uncertainty, lack of know-how, baseline and rebound complexity, and TSO–DSO coordination gaps. Technical and regulatory barriers are most clearly within the NCDR's reach. Operational barriers are partly within its reach. Economic barriers are largely beyond its direct reach.

7.2. Answering the main research question

The main research question was:

What does the alignment of current national flexibility market arrangements with the NCDR reveal about its implications for flexibility market development?

Drawing on the discussion in Section 6.2, the alignment of the French and Dutch cases reveals three related implications of the NCDR for flexibility market development.

First, the NCDR mainly harmonises common functions and processes rather than imposing a common market architecture. It establishes requirements for functions such as procurement mechanisms, baseline methodology, market coordination, and system operator coordination, while leaving room for different national market designs. France and the Netherlands use different approaches to local flexibility procurement, yet both can meet many of the same NCDR requirements. Therefore, the NCDR can promote greater regulatory consistency without requiring one uniform market model.

Second, in the two mature cases, NCDR implementation mainly involves adaptation and formalisation rather than market creation. The same requirements result in different implementation pathways because existing arrangements vary. In France, the remaining gaps mainly involve stronger integration and formalisation, particularly in TSO–DSO coordination, observability, and cross-market coordination. In the Netherlands, the main gaps concern the formalisation and completion of existing practices, especially baseline methodology and several coordination arrangements. Therefore, NCDR provides a common reference, but the changes needed to achieve alignment depend on the national starting point.

Third, the limits of regulatory alignment become clearer when the assessment results are compared with the market development barriers. The NCDR can directly address many regulatory and technical gaps, particularly those related to baseline methodology and TSO–DSO coordination. It can also partly reduce operational barriers through clearer rules on market access and information exchange.

However, it cannot, by itself, ensure market liquidity or resolve economic barriers such as revenue uncertainty. These issues also depend on the actual need for flexibility, national market choices, local network conditions, and the commercial value of flexibility.

Overall, the alignment of the two cases suggests that the NCDR can support flexibility market development by creating more consistent regulatory and operational conditions while allowing different national market models to remain in place. However, its implications extend only partly to market activity itself. Regulatory alignment alone cannot guarantee an active and commercially viable local flexibility market.

7.3. Future research

The limitations and findings of this research in suggest several directions for future research.

First, the assessment could be repeated after the NCDR enters into force. The current study provides an ex-ante assessment based on the proposed regulatory requirements. A subsequent assessment could examine how national arrangements evolve during implementation and whether the alignment gaps identified in this thesis are actually reduced. It could also test whether the expected implications for market development are observed in practice.

Second, the framework could be applied to a broader range of cases, particularly emerging or pilot flexibility markets. This would test whether the framework remains effective when national market arrangements are not yet fully developed. It could also determine whether a different, more readiness-oriented version of the framework is needed for emerging markets.

Third, future research could examine the barriers that remain partly or largely beyond the direct reach of the NCDR. In particular, further work is needed on market liquidity and the revenue uncertainty associated with flexibility. This could include comparing different remuneration and procurement arrangements and their effects on voluntary market participation.

Finally, the assessment framework could be expanded beyond regulatory alignment. Future studies might incorporate dimensions of market design and market performance, including pricing, product design, participation, liquidity, and activation volumes. This approach would enable a more robust evaluation of whether regulatory alignment correlates with effective market development.

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A

NCDR requirement extraction table

This appendix presents the complete NCDR requirement extraction table used to develop the analytical framework in Chapter 3. The table documents the relevant provisions identified from the NCDR, including their title, article reference, requirement summary, responsible actor, main category, subcategory, key aspect, and analytical implication. It serves as a traceable foundation for the development of categories and assessment indicators used in this thesis. The requirements are summarised in plain language to facilitate easier comparison of regulatory content across categories.

Table A.1: NCDR requirement extraction table_README

README – Design Requirements Table

Purpose of this file

This Excel file stores the regulatory requirements extracted from the upcoming EU Network Code on Demand Response (NCDR).

The file is used to:
- identify the main requirements in the NCDR,
- record who is responsible for each requirement,
- organise the requirements into clear categories,
- support the development of an assessment framework for local flexibility markets.

This file supports the first stage of the research: extracting and organising the NCDR requirements that are relevant to local flexibility markets.

Structure of the table

The table consists of the following columns:

Title	The title of the NCDR where the requirement comes from.
Article	The article number in the NCDR.
Article / Paragraph:	The exact reference to the provision in the NCDR text.
Requirement Summary:	A concise summary of the requirement in plain language.
Responsible Actor:	The main actor responsible for implementing, managing, or complying with the requirement, such as regulatory authority, system operator, or
Main Category:	The broad theme of the requirement.
Sub Category:	A more specific theme within the main category.
Key Aspect:	A short label that captures the main issue or focus of the requirement.
Analytical Insight / Implication:	A short note on the meaning or importance of the requirement for flexibility market design and later analysis.

Main category		Sub category	
Product design:	The specification of local flexibility products for market use.	***Product attributes:***	Minimum attributes and design considerations for congestion management and voltage control product
Pre-qualification:	The process of showing that participation is allowed before entering the market.	***Service provider qualification:***	Qualification of a market participant to act as a service provider
		Product prequalification:	Assessment of whether an service provider unit or service provider group can provide a specific product
		Grid prequalification:	Assessment of whether service provision is compatible with secure system operation
Procurement:	The process through which local flexibility is purchased in the market.	***Procurement mechanism:***	General rules and structure for market-based procurement of local services
		Pricing arrangement:	How local services may be priced and remunerated
		Market timing:	Timing of procurement, market sessions, and interaction across timeframes
		Clearing and selection:	How bids are identified, selected, and translated into procurement outcomes
		Market coordination:	Interaction of local procurement with day-ahead, intraday, balancing markets, and related mechanisms
Activation and settlement:	The process through which local services are delivered, validated, and settled.	***Baseline methodology:***	Counterfactual reference and calculation rules for determining the electrical quantities absent service activation, used as the basis for measuring delivered volumes.
		Verification:	Checking compliance or service delivery through tests, data, or actual provision
		Measurement and metering:	Measurement data, metering devices, granularity, and validation used for delivery and settlement
Governance:	The institutional arrangements that support, coordinate, and oversee the market.	***Flexibility information system:***	Common system for recording, updating, and exchanging flexibility-related qualification data
		System operator coordination:	TSO–DSO and DSO–DSO cooperation mechanisms for jointly identifying and resolving congestion and voltage issues across system boundaries.
		Reporting and monitoring:	Periodic reporting, implementation monitoring, and review of market and baselining developments

Coding approach

Each requirement is coded based on its main function in the regulation.

The coding follows these principles:
- each row represents one requirement or one clear requirement block.
- the requirement is written in plain language, not copied directly from the legal text.
- requirements are grouped by their main role in flexibility market design.
- when one provision relates to several topics, it is placed in the category that best reflects its main purpose.
- the coding is designed to support later comparison with existing local flexibility market designs.

**** Find the full table of contents of NCDR Annex 1 in the "NCDR structure" tab.***

Table A.2: NCDR requirement extraction table_NCDR structure

Title	Title name	Article	Official name
I	GENERAL PROVISIONS	Article 1	Subject matter and scope
		Article 2	Definitions
		Article 3	Objectives and regulatory aspects
		Article 4	National rules of procedure to develop common proposals
		Article 5	Adoption of terms and conditions or methodologies
		Article 6	Consultation
		Article 7	Stakeholders involvement
		Article 8	Delegation and assignment of tasks
		Article 9	Recovery of Costs
		Article 10	Confidentiality Obligations
II	GENERAL REQUIREMENTS FOR MARKET ACCESS	Article 11	National terms and conditions for service providers
		Article 12	Settlement volumes determination
		Article 13	Framework for the validation and quality of data from dedicated measurement devices
		Article 14	National terms and conditions for baselining methods
		Article 15	Validation of the baseline
III	QUALIFICATION REQUIREMENTS AND PROCESSES	CHAPTER 1	REQUIREMENTS FOR QUALIFICATION, VERIFICATION AND PREQUALIFICATION
		Article 16	Table of Equivalences
		Article 17	Qualification for service providers
		Article 18	Principles, Pre-Conditions and Applicability of the product verification and product prequalification processes
		Article 19	Requirements and process for product verification for service providing units or service providing groups
		Article 20	Requirements and process for product prequalification for service providing units or service providing groups
		Article 21	Further harmonisation of qualification, verification and prequalification requirements and processes
		Article 22	Criteria to reassessing and requiring a new product prequalification or product verification
		Article 23	Switching of controllable units between service providers
		CHAPTER 2	REQUIREMENTS FOR FLEXIBILITY DATA MANAGEMENT FOR QUALIFICATION
		Article 24	National terms and conditions for a flexibility information system
		Article 25	Principles for Governance, Accessibility and Interoperability
		Article 26	Principles and requirements for system operators responsible for one or more modules of the flexibility information system
		Article 27	Service Provider module procedures
		Article 28	Controllable Unit module procedures

Title	Title name	Article	Official name
IV	MARKET BASED PROCUREMENT OF LOCAL SERVICES	Article 29	Principles and requirements for the procurement of local services
		Article 30	Derogation from market-based procurement of local services
		Article 31	Rules for flexible connection agreements
		Article 32	Rules for market-based procurement of local services
		Article 33	Requirements for procuring system operators
		Article 34	Coordination and interoperability between local and day-ahead, intraday, and balancing markets
		Article 35	Rules for market-based procurement, pricing and settlement of local services
		Article 36	Data exchange related to settlement of local services
		Article 37	Publication of information
		Article 38	List of product attributes
		Article 39	Requirements for the definition of local products
V	OWNERSHIP OF ENERGY STORAGE FACILITIES BY SYSTEM OPERATORS	Article 40	Requirements and conditions for the ownership, development, management or operation of an energy storage facility by system operators
		Article 41	Requirements and conditions for shared ownership, development or operation of an energy storage facility by system operators and third parties
		Article 42	Assessment of cost and benefits of phasing out system operators' ownership and operation of energy storage facilities
VI	DISTRIBUTION NETWORK DEVELOPMENT PLANS	Article 43	Content and requirements of the Distribution Network Development Plan (DNDP)
		Article 44	Local services in the DNDP
VII	TSO-DSO COORDINATION AND DSO-DSO COORDINATION	Article 45	National terms and conditions for TSO-DSO and DSO-DSO coordination
		Article 46	DSO observability area
		Article 47	Forecasting and detecting physical congestion and voltage issues
		Article 48	Solving physical congestion and voltage issues
		Article 49	Grid prequalification for service providing units or service providing groups
		Article 50	Short-term procedures to account for temporary limits
		Article 51	Ensuring consistency of trade positions
		Article 52	Data exchange between DSOs and between DSOs and TSO
VIII	DATA EXCHANGE REQUIREMENTS FROM SERVICE PROVIDERS	Article 53	Organisation, roles, responsibilities, and quality of data exchange
		Article 54	Data to be provided by service providers
IX	REPORTING AND MONITORING	Article 55	ENTSO-E and EU DSO entity report on demand response
		Article 56	Monitoring
X	TRANSITIONAL AND FINAL PROVISIONS	Article 57	Final and transitional provisions
		Article 58	Entry into force

Table A.3: NCDR requirement extraction table_Product design

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
IV	38	Art. 38(1)	**The product requirements** for each **congestion management product and voltage control product** defined in the table of equivalences shall be determined based on at least the following **attributes**: availability window, preparation period, ramping period, full activation time, validity period, mode of activation, location, minimum and maximum quantity, deactivation period, minimum and maximum duration, recovery time, direction of activation, divisibility, and relevant data exchange standards.	System operator	Product design	Product attributes	Minimum attribute set for congestion management and voltage control products	This is the core NCDR requirement for product design and provides a clear benchmark for checking whether current local products are defined through a transparent and comparable attribute set.
IV	38	Art. 38(2)	In addition to the general product attributes, **voltage control products using reactive power** shall be defined based on at least the following attributes: capability to receive setpoints in real time remotely or offline, operating mode, reference voltage, voltage/reactive power characteristic, response time, voltage setpoint range, reactive power setpoint range, and target power factor with tolerance and response time.	System operator	Product design	Product attributes	Additional attribute set for reactive power voltage control products	This provision adds a more technical product-design layer for reactive-power-based voltage control and is especially relevant when assessing whether voltage-control products are sufficiently specified.
IV	38	Art. 38(3)	When system operators define new local products, they shall set their product requirements using at least the attributes referred to Art. 38(1) and Art. 38(2).	System operator	Product design	Product attributes	Use of minimum attribute set for new local products	This extends the attribute-based design requirement to future product development and supports harmonisation of new local products.
IV	39	Art. 39(1)	The national terms and conditions for service providers shall include the list of all congestion management and voltage control products to be used by system operators, including existing day-ahead, intraday or balancing products that system operators seek to use for congestion management or voltage control.	Regulatory authority	Product design	Product attributes	List of products in national terms and conditions	This requires product transparency at national level and links local product design to possible reuse of existing wholesale or balancing products.
IV	39	Art. 39(2)	System operators shall standardise local products where appropriate and avoid product fragmentation.	System operator	Product design	Product attributes	Standardisation and avoidance of product fragmentation	This is an important design principle for assessing whether local products are overly fragmented or sufficiently harmonised.
IV	39	Art. 39(3)	When defining new local products, system operators shall consider current and future system needs for capacity or energy, short-term and long-term needs described in TNDPs and DNDPs, and the current and future ability of service providers to meet the product requirements; product definition shall facilitate the effective use of local products for multiple system operators' needs.	System operator	Product design	Product attributes	Consideration of system needs and provider capability in product definition	This provision links product design to planning needs and provider capability, rather than allowing purely ad hoc product creation.
IV	39	Art. 39(4)	Local products shall correspond to the specific needs of system operators, considering at least network topology, the size and predictability of congestion or voltage issues, expected local market liquidity, the type of system users available in the area, and features affecting the availability of potential controllable units.	System operator	Product design	Product attributes	Product definition according to system and market context	This makes product design context-dependent and can be assessed by checking whether products reflect local network needs and resource characteristics.
IV	39	Art. 39(5)	Product requirements shall ensure the effective and non-discriminatory participation of system users and service providers in providing local services.	System operator	Product design	Product attributes	Non-discriminatory and effective participation through product requirements	This provision turns product design into an access issue by requiring that product requirements do not unnecessarily exclude potential participants.

Table A.4: NCDR requirement extraction table_Pre-qualification

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
I	2	Art. 2(21)	'**service provider qualification**' or '**SP qualification**' means the **process** aiming at **verifying the market participant's capability** to deliver a balancing or local service fulfilling the necessary criteria for market access, thereby becoming an authorised service provider		Pre-qualification	Service provider qualification	**Definition**	
I	2	Art. 2(24)	**'grid prequalification'** means the **process** by the connecting **system operators** and the impacted system operators to **ensure that the delivery** of balancing or local service(s) by a SPU, a SPG or parts of a SPG **does not compromise the safety and operational conditions** of connecting and impacted systems		Pre-qualification	Grid prequalification	**Definition**	
I	2	Art. 2(25)	**'product prequalification'** means the **process** of **verifying**, prior the delivery of the service, the **compliance** of a potential SPU or SPG with the **product requirements** to provide balancing or local services		Pre-qualification	Product prequalification	**Definition**	
II	11	Art. 11(3)	The national terms and conditions for service providers shall aim at simplifying access to balancing and local services and avoiding duplications where prequalification processes are justified.	Regulatory authority	Pre-qualification	Service provider qualification	Simplification of prequalification access	This provision frames prequalification as something that should be simplified and de-duplicated where justified, signalling that access barriers should be reduced across balancing and local services. It can be assessed by checking whether current LFMs use streamlined or coordinated qualification arrangements rather than repeated separate procedures.
II	11	Art. 11(4)(a)	The national terms and conditions for service providers shall specify the rules for the use of data from dedicated measurement devices, if applicable, pursuant to Article 13.	Regulatory authority	Pre-qualification	Service provider qualification	Use of dedicated measurement device data	This links qualification and participation conditions to measurement-device data rules. In practice, current LFMs can be checked for whether they clearly define what measurement devices are acceptable and how their data can be used.
II	11	Art. 11(4)(b)	The national terms and conditions for service providers shall specify the national table of equivalences and the procedures to ensure a simplification of the prequalification process pursuant to Article 16.	Regulatory authority	Pre-qualification	Service provider qualification	National table of equivalences and simplified prequalification	This is a core prequalification requirement: national rules must specify equivalence arrangements and simplification procedures. It is highly relevant for assessing whether existing LFMs rely on duplicated qualification or recognize equivalent qualifications across services.
II	11	Art. 11(4)(c)	The national terms and conditions for service providers shall specify the process and requirements for a market participant to qualify as a service provider pursuant to Article 17.	Regulatory authority	Pre-qualification	Service provider qualification	Service provider qualification process	This requires a defined qualification pathway for market participants to become service providers. It can be assessed through public platform rules on eligibility, application steps, technical criteria, and approval procedures.
II	11	Art. 11(4)(d)	The national terms and conditions for service providers shall specify the pre-conditions and applicability of product verification and product prequalification pursuant to Article 18.	Regulatory authority	Pre-qualification	Product prequalification	Preconditions and applicability of product prequalification	This provision requires national rules to define when product prequalification apply. It is relevant for checking whether current LFMs clearly distinguish product-level qualification from provider-level qualification.
II	11	Art. 11(4)(e)	The national terms and conditions for service providers shall specify the process and requirements for product verification pursuant to Article 19, and for product prequalification pursuant to Article 20.	Regulatory authority	Pre-qualification	Product prequalification	Process and requirements for product verification / prequalification	This creates a structured requirement for product-level qualification procedures. Current LFMs can be assessed on whether product verification and product prequalification are explicitly described, transparent, and procedurally clear.
II	11	Art. 11(4)(f)	The national terms and conditions for service providers shall specify the criteria to reassess and require a full or partial repetition of the product verification or product prequalification pursuant to Article 22.	Regulatory authority	Pre-qualification	Product prequalification	Reassessment and repetition criteria for product qualification	This provision extends prequalification beyond first entry by requiring rules for reassessment and repetition. It is relevant for evaluating whether current LFMs include ongoing qualification control rather than a one-off admission process.

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
III	16	Art. 16(1)	National terms and conditions shall define a national table of equivalences and simplification procedures for prequalification; where local services are procured through a market-based mechanism, these requirements shall also be part of the national terms and conditions for local service providers.	Regulatory authority; system operators	Pre-qualification	Product prequalification	National table of equivalences and simplification procedures	Creates the core framework for simplifying product prequalification across balancing and local services and links local service qualification rules to the same national structure.
III	16	Art. 16(2)	The national table of equivalences shall list product requirements by attribute, use the balancing and local product attributes defined in the Regulation, identify equivalences and relative stringency across products while considering voltage level, include simplification procedures for already registered SPUs/SPGs, and be publicly available.	Regulatory authority	Pre-qualification	Product prequalification	Content of the national table of equivalences	This makes product qualification more reusable and comparable across products. It can be assessed by checking whether current markets publish a structured and transparent equivalence table instead of duplicating product qualification requirements.
III	16	Art. 16(3)	When a new balancing or local product is created or an existing one is amended, the System operator shall add its product requirements to the table of equivalences and implement the related simplification procedures.	System operator	Pre-qualification	Product prequalification	Update of equivalence table for new or amended products	This requires product qualification rules to evolve together with product design, helping keep simplification arrangements current and usable.
III	17	Art. 17(1)	A System operator shall qualify a market participant as a service provider if the participant meets the relevant financial requirements, ICT and data-exchange capabilities, communication testing requirements where applicable, and any required descriptions of technical means, communication systems, compensation effects and rebound effects.	System operator; service provider	Pre-qualification	Service provider qualification	Service provider qualification requirements	Defines the main provider-level entry requirements. Current markets can be assessed on whether they clearly specify financial, ICT, communication, and technical documentation requirements for becoming a service provider.
III	17	Art. 17(2)	If a market participant is already qualified for at least one balancing or local product and applies for another product, the System operator shall use a simplified qualification process.	System operator	Pre-qualification	Service provider qualification	Simplified qualification for already qualified providers	This reduces duplication for providers active across several products and is directly assessable from public qualification procedures.
III	17	Art. 17(3)	If a service provider offers the same product to more than one System operator, it shall be qualified only once for that product, though each System operator may still require a communication test with minimum burden for the provider.	System operator; service provider	Pre-qualification	Service provider qualification	Single qualification for same product across multiple System operators	Supports mutual recognition of provider qualification and avoids repeated full qualification for the same product across system operators.
III	17	Art. 17(4)	The service provider shall inform the System operator about significant ICT changes affecting reliable and efficient service provision, and the System operator may require a new communication test if justified by the national terms and conditions.	Service provider; system operator	Pre-qualification	Service provider qualification	Reassessment after ICT changes	Keeps provider qualification dynamic rather than one-off by linking ongoing eligibility to ICT reliability.
III	17	Art. 17(5)	Any market participant applying to qualify as a service provider shall register all relevant qualification data in the relevant SP module of the flexibility information system, and the System operator shall verify the data.	System operator; service provider	Pre-qualification	Service provider qualification	Registration and verification of provider qualification data	Makes the flexibility information system a central tool for provider qualification.
III	17	Art. 17(6)	The System operator shall update the qualification status of the service provider in the relevant SP module of the flexibility information system within one business day.	System operator	Pre-qualification	Service provider qualification	Update of provider qualification status	This sets a short deadline for reflecting qualification decisions in the system, improving procedural transparency and speed.
III	18	Art. 18(1)	Before applying for product prequalification or product verification, the service provider shall ensure that CU data are registered in the relevant CU module and that the data of the potential SPU or SPG are registered in the relevant SP module of the flexibility information system.	Service provider	Pre-qualification	Product prequalification	Registration preconditions for product verification or prequalification	This sets the basic administrative preconditions for product-level qualification processes.
III	18	Art. 18(3)	National terms and conditions shall define the application process, starting with a formal application through the flexibility information system and ending with confirmation by the System operator that the application is complete before product verification or prequalification starts.	Regulatory authority; system operator	Pre-qualification	Product prequalification	Application process for product prequalification	Requires a formal and structured application workflow, which can be checked in market rulebooks and qualification manuals.
III	18	Art. 18(4)	The System operator is responsible for the applicable product verification or product prequalification process, and where several system operators procure the same product from the same SPU or SPG, only one System operator shall carry out the process.	System operator	Pre-qualification	Product prequalification	Responsibility for product verification or prequalification	Avoids multiple duplicative product qualification processes for the same SPU/SPG and product.

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
III	18	Art. 18(5)	By default, service providers for specific balancing, congestion management, and voltage control products are subject to product verification at SPU or SPG level; standard balancing products follow European harmonised verification or prequalification rules, and participation in the integrated scheduling process requires product prequalification.	System operator; service provider	Pre-qualification	Product prequalification	Default applicability of verification versus prequalification	This paragraph allocates which products normally require verification or prequalification and is central for comparing product-entry arrangements across markets.
III	18	Art. 18(6)	If allowed in national terms and conditions, the System operator may apply product prequalification instead of product verification for specific products in certain cases, such as failed previous verification, higher-capacity or alert/emergency balancing products, or larger congestion/voltage products above voltage-level thresholds.	System operator	Pre-qualification	Product prequalification	Conditions for using product prequalification instead of verification	This introduces a risk-based shift from lighter verification to stronger prequalification in more demanding or security-relevant cases.
III	18	Art. 18(7)	The verification or prequalification process, including the application process, shall be carried out within the shortest possible time as defined in national terms and conditions and in line with Article 23(4).	System operator	Pre-qualification	Product prequalification	Timeframe for verification or prequalification	The Regulation pushes qualification procedures toward speed and procedural efficiency.
III	18	Art. 18(8)	The service provider shall ensure that the potential SPU or SPG meets the product requirements in the national table of equivalences and can provide the System operator with the required data.	Service provider	Pre-qualification	Product prequalification	Compliance of SPU or SPG with product requirements	Makes product qualification dependent both on technical compliance and data availability.
III	18	Art. 18(9)	Approval of product verification or prequalification shall depend on the performance of the whole SPU or SPG rather than individual controllable units, and for later full or partial repetition the provider may reuse activation-test results not older than three years for unchanged controllable units.	System operator; service provider	Pre-qualification	Product prequalification	Assessment at SPU/SPG level and reuse of test results	This reduces repeated testing burden and confirms that qualification is portfolio/group-based rather than unit-by-unit.
III	18	Art. 18(10)	When a new balancing, congestion management, or voltage control product is defined, the system operator shall develop the relevant prequalification or verification process for that product in the national terms and conditions for service providers.	System operator	Pre-qualification	Product prequalification	Qualification process for newly defined products	Links product innovation directly to the need for corresponding qualification procedures.
III	19	Art. 19(1)	After an application is confirmed complete, each potential SPU or SPG shall receive temporary qualification for preliminary service provision until the System operator verifies full compliance with product requirements and verification criteria.	System operator	Pre-qualification	Product prequalification	Temporary qualification during product verification	Allows preliminary participation while the formal verification process is being completed.
III	19	Art. 19(2)	National terms and conditions shall set the maximum verification timeframe, describe the process for a negative verification result, and specify what CU-level data must be measured and stored for verification and when longer storage is required.	Regulatory authority	Pre-qualification	Product prequalification	Product verification rules and data requirements	This makes product verification procedurally transparent and links it to concrete data-retention obligations.
III	19	Art. 19(3)	If minimum verification criteria are not reached within the maximum timeframe, the System operator may require an activation test for verification purposes, if this is allowed in national terms and conditions.	System operator	Pre-qualification	Product prequalification	Activation test for verification	Provides a fallback tool when documentary or data-based verification is insufficient.
III	20	Art. 20(1)	After the application is confirmed complete, the System operator, together with the service provider, shall perform product prequalification of the potential SPU or SPG by assessing its technical characteristics against the relevant product requirements.	System operator; service provider	Pre-qualification	Product prequalification	Process for product prequalification	Defines the core technical evaluation step of product prequalification.
III	20	Art. 20(2)	As part of product prequalification, the System operator may require the SPU or SPG to pass an activation test, but only under the conditions set in national terms and conditions and only where demonstration is necessary for system security or secure network operation.	System operator	Pre-qualification	Product prequalification	Activation test for prequalification	Activation testing is allowed, but only where justified by system-security needs, limiting unnecessary burden.
III	20	Art. 20(3)	Where the potential SPU or SPG consists only of small controllable units, identical units already prequalified elsewhere, or a combination of both, the System operator shall simplify the evaluation and, if testing is needed, test only a limited number of units.	System operator	Pre-qualification	Product prequalification	Simplified prequalification for small or identical controllable units	This is one of the clearest simplification provisions for smaller or standardised resources and could be highly relevant for market participation by distributed flexibility.

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
III	21	Art. 21	**Within 12 months after entry into force**, ENTSO-E and the EU DSO entity shall propose a Union-wide methodology to further simplify product prequalification, including identifying when prequalification can be replaced by verification and where simplifications in processes, requirements, and activation tests are possible, especially for small or identical units.	ENTSO-E; EU DSO entity	Pre-qualification	Product prequalification	Union-wide methodology for further simplification of product prequalification	This is a harmonisation and simplification provision at EU level and may shape future convergence in how product prequalification is designed.
III	22	Art. 22(1)	At least 10 business days before changes to a CU, SPU or SPG, the service provider shall update the relevant CU and SPU/SPG data in the flexibility information system under the applicable update procedures.	Service provider	Pre-qualification	Product prequalification	Update of qualification-related data before changes	This creates a procedural trigger for reassessment by ensuring qualification-relevant changes are recorded in advance.
III	22	Art. 22(2)	If allowed in national terms and conditions, the System operator may require a full or partial repetition of product prequalification or product verification when there is a significant capacity change, a change in the ICT system for SPU or SPG control, or if the last qualification took place more than five years ago and the product has not been provided in the past 12 months.	System operator	Pre-qualification	Product prequalification	Criteria for reassessment and repetition of product qualification	This defines when qualification must be revisited and links reassessment to material changes, ICT changes, and inactivity.
III	22	Art. 22(3)	The System operator shall notify the service provider within one business day after the change notification if a full or partial repetition of product prequalification or verification is required.	System operator	Pre-qualification	Product prequalification	Notification of reassessment decision	This adds a short response deadline and can be assessed in terms of procedural clarity and speed.
III	22	Art. 22(4)	Where the System operator requires a full or partial repetition of product prequalification, the service provider may continue service provision with the affected SPU or SPG under the conditions set in national terms and conditions.	System operator; service provider	Pre-qualification	Product prequalification	Continuation of service during repeated product prequalification	This reduces disruption by allowing continued provision during reassessment, subject to national conditions.
III	23	Art. 23(3)(a)	After confirming the new assignment, the System operator shall assess whether a new product prequalification or product verification is needed; if it does not respond within the national deadline, no new product qualification shall be required, and if needed the regular Article 19 or 20 process shall apply.	System operator	Pre-qualification	Product prequalification	Effect of provider switching on product qualification	This links provider switching to product qualification and sets a default rule if the System operator does not respond in time.
III	23	Art. 23(3)(b)	After confirming the new assignment, the connecting and impacted system operators shall assess whether a new grid prequalification is needed; if they do not respond within the national deadline, grid prequalification is deemed not required, and if they do not require it the new service provider may use the CU from the intended switch date.	System operator	Pre-qualification	Grid prequalification	Effect of provider switching on grid prequalification	This is a key grid prequalification rule and shows how switching between service providers may trigger network-level reassessment.
III	27	Art. 27	**The SP module shall include** at least procedures for registration, application, update, suspension, de-registration, grid prequalification, switching of controllable units, revocation of qualification, and confirmation of SPU/SPG characteristics.	System operator	Pre-qualification	Service provider qualification	Minimum procedures in the SP module	This article operationalises the service-provider side of the flexibility information system and can be checked against whether case platforms support these qualification-related workflows.
III	27	Art. 27(f)	**The SP module shall include** a grid prequalification procedure allowing connecting and impacted system operators to set operational limits for SPUs, SPGs or parts of SPGs due to system constraints.	System operator	Pre-qualification	Grid prequalification	Grid prequalification procedure in the SP module	This makes grid prequalification part of the SP-module workflow and links qualification directly to network constraints.
III	28	Art. 28(e)	**The CU module shall include** a grid prequalification procedure allowing connecting system operators to validate information on controllable units connected to their system and submitted through registration or update procedures.	System operator	Pre-qualification	Grid prequalification	Grid prequalification procedure in the CU module	This embeds network validation directly into controllable-unit data management.
VII	45	Art. 45(3)(e)	The national terms and conditions for TSO-DSO and DSO-DSO coordination shall specify the processes and rules for setting and updating grid prequalification status, including methods, criteria, timeline, rules for conditional approval, responsible parties, and criteria to maximise approved results.	Regulatory authority	Pre-qualification	Grid prequalification	National rules for setting and updating grid prequalification status	This is the core national framework for grid prequalification. It can be assessed by checking whether national or platform rules clearly define status-setting, timelines, responsibilities, and conditional approval logic.

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
VII	48	Art. 48(1)(b)	Each system operator shall implement solutions to physical congestion and voltage issues that respect grid prequalification status and temporary limits.	System operator	Pre-qualification	Grid prequalification	Operational use of grid prequalification status	This shows that grid prequalification is not only an entry requirement but also an operational constraint that must be respected when activating local services.
VII	48	Art. 48(1)(c)(i)	Each system operator shall coordinate with connecting and impacted system operators and exchange necessary information so they can apply the procedures of grid prequalification and temporary limits.	System operator	Pre-qualification	Grid prequalification	Coordination to enable grid prequalification procedures	This links grid prequalification directly to coordination between operators and highlights that network-level validation depends on timely information exchange.
VII	49	Art. 49(1)	Connecting and impacted system operators shall have the right to perform grid prequalification of SPUs, SPGs or parts of SPGs before or in parallel to product prequalification or product verification to ensure that service delivery does not compromise safe system operation.	System operator	Pre-qualification	Grid prequalification	Right to perform grid prequalification	This is the basic legal basis for grid prequalification and shows that network-level assessment can run alongside product-level qualification.
VII	49	Art. 49(2)	The grid prequalification process shall not prolong the duration of the product prequalification process or delay the start of the product verification process for the relevant SPU or SPG.	System operator	Pre-qualification	Grid prequalification	Time limit interaction between grid and product qualification	This prevents grid prequalification from becoming an excessive procedural bottleneck.
VII	49	Art. 49(3)	Each connecting and impacted system operator shall forecast future system status, assess whether service delivery may create security, congestion, or voltage issues, assign one of three statuses (approved, conditionally approved, not approved), communicate the result through the flexibility information system, automatically approve if no result is communicated in time, and explain reasons where the result is conditional or negative.	System operator	Pre-qualification	Grid prequalification	Grid prequalification process and status outcomes	This is the main operational rule for grid prequalification. It provides an observable assessment basis because cases can be checked for whether they define status types, communication rules, automatic approval fallback, and justification requirements.
VII	49	Art. 49(4)	Each system operator may update the grid prequalification status when grid structural data changes, when relevant system-user data changes, or when the reassessment criteria in Article 22(2) are met.	System operator	Pre-qualification	Grid prequalification	Update of grid prequalification status	This makes grid prequalification dynamic and tied to system, user, or qualification changes rather than a one-off approval.
VII	49	Art. 49(5)	Each service provider shall respect the grid prequalification status set for its SPUs, SPGs or parts of SPGs when configuring bids and activating controllable units to deliver balancing or local services.	Service provider	Pre-qualification	Grid prequalification	Obligation to respect grid prequalification status	This connects grid prequalification to actual bidding and activation behaviour, making it an operational restriction on participation.
VII	49	Art. 49(6)	Each system operator shall maximise the number of approved grid prequalification results by using efficient national criteria, focusing grid prequalification on frequent and general scenarios, optimising safety margins, and coordinating efficiently with the temporary-limits process where applicable.	System operator	Pre-qualification	Grid prequalification	Maximising approved grid prequalification results	This provision pushes system operators to avoid unnecessarily restrictive grid prequalification and to use it efficiently.
VII	49	Art. 49(7)	The grid prequalification process shall be consistent with Regulation (EU) 2017/1485 for balancing services, and the methodology to perform grid prequalification shall be public, transparent, verifiable, and accurate.	System operator	Pre-qualification	Grid prequalification	Methodology requirements for grid prequalification	This is important for case assessment because it allows you to check whether the methodology is publicly described and whether the process is transparent.
VII	49	Art. 49(8)	The relevant system operators shall annually report to the regulatory authority on SPUs, SPGs and parts of SPGs with non-approved or conditionally approved grid prequalification and the reasons for those results.	System operator	Pre-qualification	Grid prequalification	Annual reporting on non-approved or conditionally approved grid prequalification	This adds accountability and may provide useful public or regulatory evidence about how restrictive grid prequalification is in practice.

Table A.5: NCDR requirement extraction table_Procurement

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
I	2	Art. 2(7)	**'market-based procurement'** or **'market-based mechanism'** means a procurement process for a service provision where either the selection of the service providers or the activation of the service is based on a bidding process		Procurement	Procurement mechanism	**Definition**	
IV	29	Art. 29(1)	System operators shall at least every two years assess the need for and procurement of services from demand response, energy storage facilities, or other resources as alternatives to system expansion, publicly consult on the assessment, and use it for network-planning obligations.	System operator	Procurement	Procurement mechanism	Assessment of need for procuring local services	This creates an ex-ante basis for procurement by linking market-based local services to identified flexibility needs and alternatives to network expansion.
IV	29	Art. 29(2)	System operators shall procure local services within a bidding zone through a market-based mechanism, unless a derogation is granted under Article 30.	System operator	Procurement	Procurement mechanism	Market-based procurement as the default rule	This is the central rule establishing market-based procurement as the normal model for local services.
IV	29	Art. 29(3)-(4)	Before granting or extending a derogation from market-based procurement, the regulatory authority shall require or initiate an assessment of market-based procurement in defined cases and then decide whether procurement should take place or continue.	Regulatory authority	Procurement	Procurement mechanism	Assessment and decision framework for derogation from market-based procurement	This shows that even non-market exceptions are evaluated against the market-based model, reinforcing procurement by market as the reference architecture.
IV	31	Art. 31(2)(a),(c)	Where flexible connection agreements and local-service markets coexist, activation of flexible connection agreements shall be coordinated with relevant local products through a mechanism specified in the procurement rules, and system operators activating such agreements shall ensure consistency of trade positions.	System operator	Procurement	Market coordination	Coordination of flexible connection agreements with local service markets	This provision is relevant where local-service markets coexist with flexible connection agreements and requires coordination to avoid distortion and inconsistency.
IV	32	Art. 32(1)	All system operators procuring or intending to procure local services in a market-based way shall define the procurement rules in the national terms and conditions for service providers; for reactive power, the proposal shall specify which special requirements apply according to service characteristics.	Regulatory authority	Procurement	Procurement mechanism	Procurement rules in national terms and conditions	This establishes that market-based local procurement must be governed by explicit national terms and conditions.
IV	32	Art. 32(2)	Rules for market-based procurement of local services shall be objective, transparent, non-discriminatory and technology neutral, reflect resource particularities, support efficient market access and appropriate economic signals, avoid market fragmentation, ensure coherence with other wholesale markets and timeframes, and protect confidential data while ensuring bidding and tendering transparency.	Regulatory authority	Procurement	Procurement mechanism	General principles for market-based procurement rules	This is the main principles article for procurement architecture and provides a strong benchmark for judging whether current LFMs are accessible, efficient, coherent, and transparent.
IV	32	Art. 32(3)(a)	The procurement rules shall specify the tasks and responsibilities of relevant system operators, flexibility information system operators, service providers and other market participants, including additional transparency, neutrality and business-separation requirements where third parties are assigned tasks.	Regulatory authority	Procurement	Procurement mechanism	Institutional design of procurement rules	This provision defines the institutional structure through which procurement is organised and operated.
IV	32	Art. 32(3)(b)	The procurement rules shall include provisions on coordination with operators of other markets and on how local-service procurement relates to day-ahead, intraday, and balancing markets, including whether the interrelation is sequential, parallel, simultaneous or another form.	Regulatory authority	Procurement	Market coordination	Interrelation of local procurement with other electricity markets	This is one of the core market-coordination provisions because it requires the architecture of the local market to be defined in relation to other markets.

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
IV	32	Art. 32(3)(c)	The procurement rules shall define the processes and responsibilities for bid selection and activation and for procurement, pricing and settlement of service provision in accordance with Articles 34 and 35.	Regulatory authority	Procurement	Clearing and selection	Processes and responsibilities for bid selection and activation	This is a central provision for how procurement outcomes are produced and implemented in the market.
IV	32	Art. 32(3)(d)	The procurement rules shall include a mechanism for coordinating activation of flexible connection agreements and relevant active-power local products where both coexist.	Regulatory authority	Procurement	Market coordination	Coordination mechanism for flexible connection agreements and local products	This makes coexistence between two flexibility mechanisms part of the procurement architecture.
IV	32	Art. 32(4)	Where active-power local services are procured as capacity products, activation of the corresponding energy bids from contracted resources shall be subject to competition with other available non-contracted energy bids in the relevant activation market, if such a market exists.	System operator	Procurement	Clearing and selection	Competition between contracted and non-contracted energy bids	This affects clearing logic by requiring competition at activation stage instead of automatic activation of contracted resources.
IV	32	Art. 32(5)	Where local services are procured by tender and providers may offer CU, SPU or SPG not yet connected, registered or prequalified, the national terms and conditions shall clarify timelines for registration, prequalification and other tender elements.	Regulatory authority	Procurement	Market timing	Timelines for tender participation and qualification	This provision links tender-based procurement to explicit timing rules for entry and readiness of resources.
IV	32	Art. 32(6)	**Within three years after entry into force**, ENTSO-E and the EU DSO Entity shall develop a Union-wide methodology to further specify and harmonise at least coordination with other markets, procurement methods and activated-volume calculation, stakeholder information and transparency, and the list of product attributes including relevant data exchange standards.	Regulatory authority	Procurement	Procurement mechanism	Union-wide methodology for further harmonisation of local procurement	This points to future harmonisation of core procurement-design elements at EU level.
IV	33	Art. 33(1)-(2)	Each procuring system operator shall act in a non-discriminatory manner when procuring and using congestion management or voltage control products and shall not exchange preferential, confidential or commercially sensitive information with affiliated companies and service providers.	System operator	Procurement	Procurement mechanism	Neutrality and non-discrimination of procuring system operators	This sets basic conduct requirements for procuring system operators and supports fair procurement processes.
IV	33	Art. 33(3)	Each procuring system operator shall identify bids, SPUs, parts of SPGs or volumes that can solve physical congestion or voltage issues in accordance with Articles 47 and 48.	System operator	Procurement	Clearing and selection	Identification of bids able to solve local issues	This connects bid selection directly to the physical purpose of the procurement.
IV	33	Art. 33(5)(e)-(g)	Each procuring system operator shall provide, maintain and operate IT solutions that implement procurement, pricing and settlement rules, support communication with service providers and other system operators for required data exchange and procurement results, and communicate with the flexibility information system where applicable.	System operator	Procurement	Procurement mechanism	IT support for procurement operation	This provision shows that procurement architecture includes operational IT capability and interfaces with both actors and the FIS.
IV	33	Art. 33(6)-(7)	Procuring system operators shall coordinate with other procuring system operators according to the procurement rules; subject to provider consent, they may forward active-power bids to other markets, and all procuring system operators in one Member State shall have a common information platform, standardised definitions, and standardised use of locational information, with coordination and interoperability requirements specified in the procurement rules.	System operator	Procurement	Market coordination	Coordination between procuring system operators and with other markets	This is a major market-architecture provision because it links local procurement to bid forwarding, shared information platforms, and interoperability across procuring operators.

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
IV	34	Art. 34(1)	Where bids offered in day-ahead, intraday and balancing markets are used to solve physical congestion or voltage issues, the procurement rules shall consistently describe the coordination between involved parties and ensure that local-market arrangements do not override or compromise the rules of other wholesale markets.	Regulatory authority	Procurement	Market coordination	Coordination with day-ahead, intraday and balancing markets	This is the core interoperability provision between local and wholesale markets.
IV	34	Art. 34(2)	Service providers shall be allowed to submit the same bid in several markets, but the bid shall not be selected twice for the same market time unit; if a bid is not selected, or the selected service is no longer needed, it may be submitted to another market, and controllable units may be registered in different SPGs for different services provided double activation is avoided.	Service provider	Procurement	Market coordination Clearing and selection	Avoidance of double selection and double activation	This provision is central for multi-market participation and clearing logic across overlapping market opportunities.
IV	34	Art. 34(3)	Where services are offered in another market directly, through an intermediary, or via bid forwarding by a procuring system operator, the procurement rules shall include at least requirements for forwarding, handling consent, inclusion of locational information, transparency of forwarded bids, changes or withdrawal of bids, rights and liabilities, pricing and compensation, avoidance of double selection, and handling of forwarded or combined bids for service validation.	Regulatory authority	Procurement	Market coordination	Rules for bid forwarding and cross-market participation	This is one of the clearest market-architecture articles because it specifies how local bids can interact with other markets without double use or loss of transparency.
IV	35	Art. 35(1)	**The procurement rules** shall include the process for market-based procurement of local services through products, including tender-based procurement where applicable, the characteristics of the procured products, bid selection criteria, the pricing mechanism, and the settlement process.	Regulatory authority	Procurement	Procurement mechanism	Minimum content of procurement rules for local services	This is a central structuring provision for how the procurement process must be designed.
IV	35	Art. 35(2)	**The pricing mechanism** for market-based procurement of local services shall ensure cost-efficient activation of bids, take account of actual market structure and concentration, and provide incentives for long-term market development.	Regulatory authority	Procurement	Pricing arrangement	Pricing principles for local-service procurement	This is the core NCDR provision on the objectives of local-market pricing.
IV	35	Art. 35(3)	The pricing mechanism shall allow variations by product, voltage level, time horizon, market liquidity, local features and service purpose; allow predetermined prices for contracted availability or activation subject to economic-efficiency assessment; allow energy-only and/or capacity payments subject to economic-efficiency assessment; and allow deviation from general price mechanisms in wholesale markets where procurement takes place there.	Regulatory authority	Procurement	Pricing arrangement	Permitted forms and variations of pricing arrangement	This provision gives flexibility in remuneration design and is highly relevant for comparing current pricing arrangements across LFMs.
IV	37	Art. 37(1)	Each procuring system operator shall publish clear information on market sessions, including the number and structure of sessions, gate closure times, and information on traded products, no later than two months before launch or amendment.	System operator	Procurement	Market timing	Publication of market-session structure and gate closure times	This directly supports participant access to the market by making timing and session structure visible in advance.
IV	37	Art. 37(2)-(4)	System operators shall publish relevant information to promote liquidity, including indicative expected needs for local services, information necessary for operation of local markets, and aggregated information on offered and selected bids, resulting costs, temporary-limit effects, and activated volumes of flexible connection agreements after procurement results.	System operator	Procurement	Clearing and selection	Publication of market needs and procurement results	This provision supports transparency of procurement outcomes and market functioning and can be used to assess how observable local-market results are in practice.

Table A.6: NCDR assessment framework_Activation and settlement table

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
-	-	(11)	A properly designed baselining method is probably one of the most important determinants of the successful conduct of any DR service as it enables system operators and system users to measure performance of DR resources. The relevant methods should contain a balance of the essential qualities of accuracy, simplicity, integrity and alignment. The national terms and conditions on baseline calculation will include the details necessary to create the baselines used in the settlement of the demand response services. A European registry for all implemented baselining methods will serve as the basis for further harmonisation.	Regulatory authority	Activation and settlement	Baseline methodology	Baseline methodology	Baseline methodology becomes a core settlement requirement under NCDR. Current markets may need to adapt their verification and settlement rules to ensure baselines are accurate, simple, robust, and capable of future harmonisation. Other relevant methods are allowed as well.
I	2	Art. 2(2)	**'baseline'** means a counterfactual reference about the electrical quantities that would have been withdrawn or injected if there had been no activation of any balancing or local services, or no activation of demand response in any other wholesale market	-	Activation and settlement	Baseline methodology	**Definition**	
I	2	Art. 2(3)	**'baselining method'** means the formula for the calculation of a specific baseline or the set of data constituting the specific baseline	-	Activation and settlement	Baseline methodology	**Definition**	
II	14	Art. 14(1)	All system operators of a Member State shall, **within 12 months** after approval of the national rules of procedure, develop a common proposal on the processes for the definition, calculation and validation of baselining methods.	System operators	Activation and settlement	Baseline methodology	Baseline governance framework	Creates a mandatory national baseline framework for local services and balancing-related uses, meaning baseline design is not optional and must be jointly specified by system operators at Member State level.
II	14	Art.14(2)(a)	The national terms and conditions shall include the roles and responsibilities of market participants providing balancing, local services and participating in other wholesale markets regarding the development and implementation of baselining methods, including a process through which relevant stakeholders may propose baselining methods.	Regulatory authority; system operators	Activation and settlement	Baseline methodology	Roles and responsibilities for baselines	Baseline design becomes institutionally structured: roles, responsibilities, and stakeholder input must be formalised, which can affect who may shape settlement methodologies in current flexibility markets.
II	14	Art.14(2)(b)	The national terms and conditions shall include the process for validating the baseline.	Regulatory authority; system operators	Activation and settlement	Baseline methodology	Baseline validation process	Makes validation an explicit procedural requirement, so current markets need a clear and auditable process to verify whether baseline calculations are acceptable for settlement.
II	14	Art.14(2)(c)	The national terms and conditions shall include the minimum set of data necessary to implement the respective baselining method and the granularity required by the relevant market time unit or service provision.	Regulatory authority; system operators	Activation and settlement	Baseline methodology	Data requirements and granularity	Baseline implementation must be supported by minimum data specifications and time granularity rules, which may require current markets to upgrade metering, data access, or settlement-resolution arrangements.
II	14	Art.14(2)(d)	The national terms and conditions shall include an obligation to share necessary data with all relevant stakeholders for implementing the respective baselining method, and the frequency for sharing such data, as required by the relevant market time unit or service provision.	Regulatory authority; system operators	Activation and settlement	Baseline methodology	Data sharing for baselines	Introduces an explicit data-sharing obligation linked to baseline implementation, making information exchange a core settlement requirement rather than a voluntary market design choice.

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
II	14	Art.14(2)(e)	The national terms and conditions shall include a recurring evaluation process to assess whether a proposed baselining method from outside the European baselining method register is fit for purpose.	Regulatory authority; system operators	Activation and settlement	Baseline methodology	Fit-for-purpose evaluation of baselines	Allows innovation beyond the EU register, but only through recurring assessment, so national frameworks must balance harmonisation with controlled methodological flexibility.
II	14	Art.14(3)(a)	Baselining methods shall be recalculable and transparent.	Regulatory authority; system operators	Activation and settlement	Baseline methodology	Baseline quality principle: transparency and recalculability	Sets core design principles for baselines and raises the minimum quality standard for current market methodologies.
II	14	Art.14(3)(b)	Baselining methods shall prevent abusive behaviour.	Regulatory authority; system operators	Activation and settlement	Baseline methodology	Baseline integrity / anti-gaming	Baseline methodology is explicitly linked to market integrity, meaning settlement rules must be robust against manipulation and strategic behaviour.
II	14	Art.14(3)(c)	Baselining methods shall be precise, accurate and unbiased so that they deliver reliable results.	Regulatory authority; system operators	Activation and settlement	Baseline methodology	Baseline quality principle: reliability and accuracy	Current markets may need to review whether their baseline methods are sufficiently accurate and unbiased to meet a harmonised legal standard.
II	14	Art.14(3)(d)	Baselining methods shall consider compensation effects and, if applicable, also any proven rebound effects.	Regulatory authority; system operators	Activation and settlement	Baseline methodology	Treatment of compensation and rebound effects	Baseline methodologies must account for behavioural and operational distortions, which can make settlement design more sophisticated than simple before/after measurement.
II	14	14(3)(e)	Baselining methods shall, if possible, use the existing available data.	Regulatory authority; system operators	Activation and settlement	Baseline methodology	Data minimisation / use of existing data	The Regulation supports pragmatic implementation by preferring use of existing data where possible, which may reduce administrative burden while still constraining baseline design choices.
II	14	Art.14(4)	**Within 24 months after entry into force**, ENTSO-E and the EU DSO entity shall publish on their website a baselining method register based on Member States' approved baselining methods, with information at least per resource type and product, updated at least yearly, and explained in English.	ENTSO-E; EU DSO entity	Activation and settlement	Baseline methodology	European baselining method register	Creates an EU-level transparency and harmonisation mechanism for baseline methods, enabling comparability across Member States and potentially shaping convergence in local flexibility market settlement design.
II	15	Art.15(1)	Where the data used for determining the provision of a service is based on measurement, the granularity of the data used shall be the imbalance settlement period, unless higher resolution is required by the procuring system operator to determine service delivery.	System operator; service provider	Activation and settlement	Baseline methodology	Data granularity for validation	Sets a default validation data resolution linked to the imbalance settlement period while allowing the procuring system operator to require finer granularity where necessary. Current flexibility markets may need to align metering and validation practices with this minimum standard.
II	15	Art.15(2)	The procuring system operator shall have the right to require from the service provider all data necessary to validate the provision of the respective service.	System operator; service provider	Activation and settlement	Baseline methodology	Data access right for validation	Strengthens the validation authority of the procuring system operator by establishing an explicit right to request all necessary validation data from service providers. This may require clearer contractual and data-sharing arrangements in current markets.
II	15	Art.15(3)	Concerned stakeholders identified within the Member State shall have the right to receive from the respective system operator relevant customer data, upon customer consent, to execute validation of a service provided to system operators, provided this does not violate commercially sensitive information rules or Regulation (EU) 2016/679.	System operator	Activation and settlement	Baseline methodology	Third-party access to validation data	Introduces a conditional right for relevant stakeholders to access customer-related validation data, subject to consent and data-protection/confidentiality limits. This can support more robust validation ecosystems, but may require national rules on who qualifies as a concerned stakeholder and how consent and confidentiality are managed.

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
					Activation and settlement			
I	2	Art. 2(26)	**'product verification'** means the process of verifying, after the delivery of service, the compliance of a SPU or SPG with the product requirements to provide balancing or local services		Activation and settlement	Verification	**Definition**	
II	11	Art. 11(4)(d)	The national terms and conditions for service providers shall specify the pre-conditions and applicability of product verification and product prequalification pursuant to Article 18.	Regulatory authority	Activation and settlement	Verification	Applicability of product verification	This provision requires national rules to define when product verification.
II	11	Art. 11(4)(e)	The national terms and conditions for service providers shall specify the process and requirements for product verification pursuant to Article 19, and for product prequalification pursuant to Article 20.	Regulatory authority	Activation and settlement	Verification	Process and requirements for product verification	This creates a structured requirement for verification procedures. Current LFMs can be assessed on whether product verification are explicitly described, transparent, and procedurally clear.
II	11	Art. 11(4)(f)	The national terms and conditions for service providers shall specify the criteria to reassess and require a full or partial repetition of the product verification or product prequalification pursuant to Article 22.	Regulatory authority	Activation and settlement	Verification	Reassessment and repetition criteria for product verification	This provision extends verification beyond first entry by requiring rules for reassessment and repetition. It is relevant for evaluating whether current LFMs include ongoing verification control rather than a one-off admission process.
III	18	Art. 18(1)	Before applying for product verification, the service provider shall ensure that CU data are registered in the CU module and that the data of the potential SPU or SPG are registered in the SP module of the flexibility information system.	Service provider	Activation and settlement	Verification	Registration preconditions for product verification	This sets the basic administrative preconditions for starting a product verification process.
III	18	Art. 18(3)	National terms and conditions shall define the application process, starting with a formal application through the flexibility information system and ending with confirmation by the system operator that the application is complete before product verification starts.	Regulatory authority	Activation and settlement	Verification	Application process for product verification	This requires a formal and transparent workflow before verification can begin.
III	18	Art. 18(4)	The system operator shall be responsible for the product verification process for each product, and where several system operators procure the same product from the same SPU or SPG, only one system operator shall carry out the process.	System operator	Activation and settlement	Verification	Responsibility for product verification	This avoids duplicated verification of the same SPU or SPG for the same product.
III	18	Art. 18(5)	By default, service providers for specific balancing, congestion management, and voltage control products shall be subject to product verification at SPU or SPG level; standard balancing products follow harmonised European arrangements, and integrated scheduling requires product prequalification.	System operator	Activation and settlement	Verification	Default applicability of product verification	This paragraph defines where verification is the default entry route and is important for comparing product-entry rules across markets.
III	18	Art. 18(6)	If allowed in national terms and conditions, the system operator may apply product prequalification instead of product verification for specific products in defined cases, such as failed previous verification, larger-capacity balancing products, or larger congestion or voltage products above voltage-level thresholds.	System operator	Activation and settlement	Verification	Conditions to replace verification with prequalification	This shows that verification is the default for many products, but stricter prequalification may replace it in more demanding or security-sensitive cases.
III	18	Art. 18(7)	The verification process, including the application process, shall be carried out within the shortest possible time as defined in national terms and conditions and in line with the switching-time requirements in Article 23(4).	System operator	Activation and settlement	Verification	Timeframe for product verification	This pushes verification toward procedural speed and limits administrative delay.

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
III	18	Art. 18(8)	The service provider shall ensure that its potential SPU or SPG meets the product requirements for which product verification is required according to the national table of equivalences and can provide the required data to the system operator.	Service provider	Activation and settlement	Verification	Compliance with product requirements for verification	This makes verification depend on both technical compliance and data availability.
III	18	Art. 18(9)	Approval of product verification shall depend on the performance of the whole SPU or SPG rather than individual controllable units, and for later full or partial repetition the service provider may reuse activation-test results not older than three years for unchanged controllable units.	System operator	Activation and settlement	Verification	Assessment at SPU/SPG level and reuse of results	This confirms that verification is group-based and may reuse earlier test results to reduce burden.
III	18	Art. 18(10)	When a system operator defines a new balancing, congestion management, or voltage control product, it shall develop the corresponding verification process in the national terms and conditions for service providers.	System operator	Activation and settlement	Verification	Verification process for newly defined products	This links product innovation directly to the need for a defined verification process.
III	19	Art. 19(1)	After the system operator confirms that the application is complete, each potential SPU or SPG shall receive temporary qualification for preliminary service provision until the system operator verifies full compliance with product requirements and verification criteria.	System operator	Activation and settlement	Verification	Temporary qualification during product verification	This allows preliminary participation while the formal verification process is being completed.
III	19	Art. 19(2)	National terms and conditions shall set the maximum verification timeframe, describe the process for a negative verification result, and specify what CU-level data must be measured and stored for verification and when longer storage is required.	Regulatory authority	Activation and settlement	Verification	Product verification rules and data requirements	This is the main procedural rulebook for verification and provides clear assessment points for case comparison.
III	19	Art. 19(3)	If the minimum verification criteria are not reached within the maximum timeframe, the system operator may require an activation test for verification purposes, if this is allowed in the national terms and conditions.	System operator	Activation and settlement	Verification	Activation test for verification	This provides a fallback verification tool where documentary or data-based verification is insufficient.
III	21	Art. 21	ENTSO-E and the EU DSO entity shall develop a Union-wide methodology to further simplify product prequalification, including identifying cases where product prequalification can be replaced by product verification and where simplifications in processes, requirements, and activation tests are possible, especially for small or identical units.	Regulatory authority	Activation and settlement	Verification	Union-wide methodology affecting the role of verification	This may expand the use of verification as a lighter alternative to prequalification in future harmonised arrangements.
III	22	Art. 22(1)	At least 10 business days before changes to a CU, SPU or SPG, the service provider shall update the relevant CU and SPU/SPG data in the flexibility information system under the applicable update procedures.	Service provider	Activation and settlement	Verification	Update of data before reassessment of verification	This creates the procedural trigger for possible reassessment of product verification.
III	22	Art. 22(2)	If allowed in national terms and conditions, the system operator may require a full or partial repetition of product verification when there is a significant capacity change, a change in the ICT system for SPU or SPG control, or if the last qualification took place more than five years ago and the product has not been provided in the past 12 months.	System operator	Activation and settlement	Verification	Criteria for reassessment and repetition of product verification	This defines when product verification must be revisited and ties repetition to material changes, ICT changes, and inactivity.
III	22	Art. 22(3)	The system operator shall notify the service provider within one business day after the change notification if a full or partial repetition of product verification is required.	System operator	Activation and settlement	Verification	Notification of repeated product verification	This adds a short response deadline and strengthens procedural clarity.

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
II	12	Art. 12(1)	Settlement of system operation services and imbalance settlement shall be based on the metering equipment of the connection point. Data from dedicated measurement devices shall be used for settlement of balancing and local services and demand response where the smart meter is absent or insufficient, and where the dedicated device provides sufficiently granular, reliable, and quality-compliant data.	System operator	Activation and settlement	Measurement and metering	Use of dedicated measurement devices for settlement	This establishes the basic hierarchy for settlement measurement: connection-point metering as the default, with dedicated measurement devices allowed where smart-meter data is missing or insufficient and quality requirements are met.
II	12	Art. 12(2)	A controllable unit connected to a metering point with a conventional meter may only be allowed to be an SPU or part of an SPU or SPG if sufficiently granular, reliable, and quality-compliant data, including from dedicated measurement devices where relevant, enable the calculation of that controllable unit's injections and withdrawals as reflected at the connection point.	System operator	Activation and settlement	Measurement and metering	Metering conditions for controllable units with conventional meters	This provision makes participation possible even with conventional meters, but only where measurement data is good enough to quantify the controllable unit's energy contribution.
II	13	Art. 13(1)	National terms and conditions, or national legislation where applicable, shall define rules for the use of data from dedicated measurement devices, including data-exchange requirements for data-quality verification, service validation and settlement, rules and responsibilities for verifying data quality and calculating validation data where raw data is unavailable or insufficient, and principles for collection, management, transfer, and storage of such data.	Regulatory authority	Activation and settlement	Measurement and metering	National rules for dedicated measurement device data	This is the main framework article for dedicated measurement-device data and can be assessed by checking whether national or platform rules define data quality, validation, settlement use, fallback calculation, and handling requirements.
II	13	Art. 13(2)	When data from a dedicated measurement device is used for settlement or validation, and unless national terms and conditions provide otherwise, the service provider shall access the relevant measurement data and make it available to the procuring system operator.	Service provider	Activation and settlement	Measurement and metering	Service provider duty to provide measurement data	This assigns the default responsibility for accessing and providing dedicated-device measurement data to the service provider.
II	13	Art. 13(3)	When data from a dedicated measurement device is used for validation or settlement, system operators shall be entitled to verify the quality of the measurements provided by the device.	System operator	Activation and settlement	Measurement and metering	System operator right to verify measurement quality	This gives system operators an explicit right to check whether dedicated-device measurements are trustworthy enough for validation and settlement.
II	13	Art. 13(4)	When verifying measurement quality, system operators may use, with the relevant system user's consent and on a non-discriminatory basis, the standardised or remote interface for non-validated near real-time data, as well as calculations and measurements from other sources.	System operator	Activation and settlement	Measurement and metering	Methods for verifying measurement quality	This provision broadens the tools available for checking measurement quality and supports cross-checking against alternative data sources.
II	15	Art. 15(1)	Where the data used to determine service provision is measurement-based, the data granularity shall be the imbalance settlement period unless the procuring system operator requires higher resolution to determine service delivery.	System operator	Activation and settlement	Measurement and metering	Data granularity for service validation	This sets a default measurement granularity for validating service provision while allowing higher resolution where operationally needed.
II	15	Art. 15(2)	The procuring system operator shall have the right to require from the service provider all data necessary to validate the provision of the respective service.	System operator	Activation and settlement	Measurement and metering	Data access right for service validation	This strengthens the operator's ability to validate delivery by establishing a clear right to request all necessary validation data.
II	15	Art. 15(3)	Concerned stakeholders identified within the Member State shall have the right to receive from the respective system operator relevant customer data, upon customer consent, to validate a service provided to system operators, provided this does not violate commercially sensitive information or data-protection rules.	System operator	Activation and settlement	Measurement and metering	Third-party access to data for service validation	This creates a conditional pathway for third-party validation by allowing access to relevant customer data, subject to consent and confidentiality limits.

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
IV	35	Art. 35(4)(a)	The rules for **settlement of market-based procured local services** shall include a procedure for calculating the activated volume and delivery of local services, using the relevant baseline when necessary, taking account of compensation effects where applicable, and assessing how service provision is reflected at the relevant connection point or points.	Regulatory authority	Activation and settlement	Measurement and metering	Procedure for calculating activated volume and delivery	This is a core measurement-and-settlement requirement because it links activated-volume calculation to baseline use, compensation effects, and the reflection of service delivery at the connection point.
IV	35	Art. 35(4)(c)	The rules for **settlement** shall include a procedure for validating, where system limitations or temporary limits are set, that these constraints are respected.	Regulatory authority	Activation and settlement	Measurement and metering	Validation of compliance with system or temporary limits	This creates a measurement-related validation requirement tied to system and temporary constraints, which can be assessed through case rules on how compliance is checked.
IV	35	Art. 35(5)	Each relevant system operator shall be responsible for calculating the activated local services at least for each market time unit defined in the product characteristics, for each direction, and for each SPU or SPG.	System operator	Activation and settlement	Measurement and metering	Granularity of activated local service calculation	This requires activated-volume calculation to be structured by time unit, direction, and SPU/SPG, which gives a clear observable benchmark for case comparison.
IV	36	Art. 36(1)	Each relevant system operator and eligible market party shall be entitled to receive the necessary measurement values or activation information sent by the service provider for calculating the activated volume of local service energy, at least for each market time unit, in a standardised national data-exchange format, and whenever updated data is available.	System operator	Activation and settlement	Measurement and metering	Measurement values and activation information for activated-volume calculation	This provision directly concerns the measurement and activation data needed to calculate activated local service energy and requires standardised and updateable exchange.
IV	36	Art. 36(3)	Where required for validating the activated volume of local services, each relevant system operator shall, on request, receive the necessary ex-ante mapping information from the service provider, the necessary metering or measurement values for controllable units or the metering point, and the necessary baseline of the controllable units or metering point.	System operator	Activation and settlement	Measurement and metering	Validation data for activated local service volumes	This is one of the strongest measurement-and-metering provisions because it explicitly requires access to metering values, measurement values, and mapping information for validation of activated volumes.
IV	36	Art. 36(6)	Each recipient of data received under the settlement data-exchange rules shall ensure that the data is processable and shall inform the sender without undue delay if the data is not processable.	System operator	Activation and settlement	Measurement and metering	Processability of settlement-related measurement and activation data	This supports the practical usability of measurement and settlement data by imposing a basic processability requirement and an error-notification obligation.
VIII	54	Art. 54(4)	Each relevant service provider shall provide schedule data, where required, including the program schedule or calculated baseline of the SPG, parts of SPG or SPU, the contribution of CUs, SPUs and parts of SPG to the SPG bid, and scheduled unavailability of SPUs, SPGs and parts of SPGs.	Service provider	Activation and settlement	Measurement and metering	Schedule data for service provision	This provision supplies core operational reference data needed to interpret service delivery, including baseline-linked schedule data and unit contribution information.
VIII	54	Art. 54(5)	The schedule data defined in paragraph 4 shall be provided at least in day-ahead and shall be updated after subsequent market sessions.	Service provider	Activation and settlement	Measurement and metering	Timing and updating of schedule data	This sets a minimum temporal requirement for schedule data and ensures that the data used for operational and settlement purposes stays updated after later market sessions.
VIII	54	Art. 54(6)	Each relevant service provider shall provide near real-time data, where required, including the operation status of the SPU, active and reactive power flow of the SPU, SPG or parts of SPG, unexpected unavailability of the SPU or SPG, voltage at the connection point where available, storage-device data and state of charge where applicable, and data needed to monitor service provision.	Service provider	Activation and settlement	Measurement and metering	Near real-time operational data for monitoring and validation	This is one of the strongest measurement-and-metering provisions because it specifies the near real-time operational data that may be needed to validate and monitor service provision.
VIII	54	Art. 54(7)	For voltage control services using reactive power, the information exchange shall include bidirectional real-time data exchange between the SPU or SPG and system operators, and data exchange from system operators to the SPU or SPG including at least a setpoint for provision of the voltage control service.	System operator	Activation and settlement	Measurement and metering	Real-time data exchange for reactive power voltage control	This provision adds a real-time measurement and control communication requirement for reactive-power-based voltage control services.
VIII	54	Art. 54(8)	Service providers shall not be required to provide near real-time data at CU level for SPUs or SPGs that consist only of small controllable units.	Service provider	Activation and settlement	Measurement and metering	Exemption from CU-level near real-time data for small units	This provision limits data burden for portfolios made up only of small controllable units, which may be important for proportionality in market participation.

Table A.7: NCDR requirement extraction table_Governance

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
I	2	Art. 2(15)	**'flexibility information system'** means a system to record at least the qualification of service providers, the product prequalification, product verification and grid prequalification of SPUs and SPGs and the switch of controllable units for the provision of balancing and local services and to exchange data for such processes;	-	Governance	Flexibility information system	**Definition**	
III	24	Art. 24(1)	All system operators of a Member State shall develop a proposal for national terms and conditions for a flexibility information system **within 18 months after approval of the national rules of procedure**.	Regulatory authority	Governance	Flexibility information system	National terms and conditions for the flexibility information system	This creates the formal national basis for establishing and governing the flexibility information system.
III	24	Art. 24(2)	The national terms and conditions for a flexibility information system shall specify a stepwise national implementation process for a common system and standardised data exchange procedures, including governance and accessibility, module functional requirements, requirements for responsible system operators, the data management structure with responsible parties and access rights, and specifications of SP and CU module procedures and related data exchanges, including parties involved and the format, content, scope, granularity, timing and periodicity of exchange.	Regulatory authority	Governance	Flexibility information system	Minimum content of national terms and conditions for the flexibility information system	This is the core framework requirement for the FIS and provides a strong basis for case assessment of whether a national or platform arrangement defines governance, access, modules, and related data procedures.
III	25	Art. 25(1)	Each Member State shall have a common flexibility information system to simplify, standardise and streamline the qualification of service providers, product prequalification and verification, grid prequalification, switching of controllable units, and the corresponding data exchanges for balancing and local services.	Regulatory authority	Governance	Flexibility information system	Common flexibility information system	This establishes the FIS as a common infrastructure rather than an optional tool and defines its core functional scope.
III	25	Art. 25(2)	The flexibility information system shall have a single and common access point for service providers, system users and other entitled parties to read, register, administer or update information on SPUs, SPGs and CUs according to their responsibility or authorisation.	System operator	Governance	Flexibility information system	Single and common access point	This requires a unified access structure and supports procedural simplicity and transparency.
III	25	Art. 25(3)	The single and common access point of the flexibility information system shall include a nationally harmonised online application with a graphical user interface and a nationally harmonised application programming interface.	System operator	Governance	Flexibility information system	Harmonised online application and API	This pushes the FIS toward standardised digital access and interoperability.
III	25	Art. 25(4)	Each procuring system operator shall be responsible for operating and maintaining one or more SP modules and one or more CU modules; if a centralised FIS with a single SP and CU module is required, the national terms and conditions shall specify the responsible operator, group of operators or other entity.	System operator	Governance	Flexibility information system	Responsibility for operating and maintaining SP and CU modules	This clarifies who runs the FIS infrastructure and whether it is decentralised or centralised.
III	25	Art. 25(5)	To avoid vendor and operator lock-in, all data stored in the SP and CU modules shall be portable, and responsible system operators shall ensure export to a common European or national standard in a structured, machine-readable and documented format, together with a well-defined export procedure for data migration and suspension of module operation.	System operator	Governance	Flexibility information system	Data portability and export procedure	This is an important interoperability safeguard and can be assessed through whether the system allows standardised export and migration of data.
III	26	Art. 26(1)	System operators responsible for any part of the flexibility information system shall provide non-discriminatory online access in structured and machine-readable format through the common access point, provide a national online application and API meeting the ETSI-CEN-CENELEC standards, provide test environments with suitable test data, cooperate to ensure interoperability of modules, ensure one-time registration/update/deletion of the same information, maintain and publish a list of actors with access or update rights and their purposes, and make public a non-confidential version of the FIS including at least service-provider data and total prequalified or verified capacity per technology and product.	System operator	Governance	Flexibility information system	General requirements for system operators responsible for the flexibility information system	This is the main operational requirement set for FIS management and provides multiple observable indicators such as non-discriminatory access, test environments, one-time data entry, interoperability, and public non-confidential information.

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
I	2	Art. 2(15)	**'flexibility information system'** means a system to record at least the qualification of service providers, the product prequalification, product verification and grid prequalification of SPUs and SPGs and the switch of controllable units for the provision of balancing and local services and to exchange data for such processes;	-	Governance	Flexibility information system	**Definition**	
III	24	Art. 24(1)	All system operators of a Member State shall develop a proposal for national terms and conditions for a flexibility information system **within 18 months after approval of the national rules of procedure**.	Regulatory authority	Governance	Flexibility information system	National terms and conditions for the flexibility information system	This creates the formal national basis for establishing and governing the flexibility information system.
III	24	Art. 24(2)	The national terms and conditions for a flexibility information system shall specify a stepwise national implementation process for a common system and standardised data exchange procedures, including governance and accessibility, module functional requirements, requirements for responsible system operators, the data management structure with responsible parties and access rights, and specifications of SP and CU module procedures and related data exchanges, including parties involved and the format, content, scope, granularity, timing and periodicity of exchange.	Regulatory authority	Governance	Flexibility information system	Minimum content of national terms and conditions for the flexibility information system	This is the core framework requirement for the FIS and provides a strong basis for case assessment of whether a national or platform arrangement defines governance, access, modules, and related data procedures.
III	25	Art. 25(1)	Each Member State shall have a common flexibility information system to simplify, standardise and streamline the qualification of service providers, product prequalification and verification, grid prequalification, switching of controllable units, and the corresponding data exchanges for balancing and local services.	Regulatory authority	Governance	Flexibility information system	Common flexibility information system	This establishes the FIS as a common infrastructure rather than an optional tool and defines its core functional scope.
III	25	Art. 25(2)	The flexibility information system shall have a single and common access point for service providers, system users and other entitled parties to read, register, administer or update information on SPUs, SPGs and CUs according to their responsibility or authorisation.	System operator	Governance	Flexibility information system	Single and common access point	This requires a unified access structure and supports procedural simplicity and transparency.
III	25	Art. 25(3)	The single and common access point of the flexibility information system shall include a nationally harmonised online application with a graphical user interface and a nationally harmonised application programming interface.	System operator	Governance	Flexibility information system	Harmonised online application and API	This pushes the FIS toward standardised digital access and interoperability.
III	25	Art. 25(4)	Each procuring system operator shall be responsible for operating and maintaining one or more SP modules and one or more CU modules; if a centralised FIS with a single SP and CU module is required, the national terms and conditions shall specify the responsible operator, group of operators or other entity.	System operator	Governance	Flexibility information system	Responsibility for operating and maintaining SP and CU modules	This clarifies who runs the FIS infrastructure and whether it is decentralised or centralised.
III	25	Art. 25(5)	To avoid vendor and operator lock-in, all data stored in the SP and CU modules shall be portable, and responsible system operators shall ensure export to a common European or national standard in a structured, machine-readable and documented format, together with a well-defined export procedure for data migration and suspension of module operation.	System operator	Governance	Flexibility information system	Data portability and export procedure	This is an important interoperability safeguard and can be assessed through whether the system allows standardised export and migration of data.
III	26	Art. 26(1)	System operators responsible for any part of the flexibility information system shall provide non-discriminatory online access in structured and machine-readable format through the common access point, provide a national online application and API meeting the ETSI-CEN-CENELEC standards, provide test environments with suitable test data, cooperate to ensure interoperability of modules, ensure one-time registration/update/deletion of the same information, maintain and publish a list of actors with access or update rights and their purposes, and make public a non-confidential version of the FIS including at least service-provider data and total prequalified or verified capacity per technology and product.	System operator	Governance	Flexibility information system	General requirements for system operators responsible for the flexibility information system	This is the main operational requirement set for FIS management and provides multiple observable indicators such as non-discriminatory access, test environments, one-time data entry, interoperability, and public non-confidential information.

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
III	26	Art. 26(2)	System operators responsible for operating an SP module shall administer and make available SP, SPU and SPG data, grant timely access to service providers and entitled actors, inform affected actors of Article 27 procedures without undue delay, make relevant data changes available without undue delay, and ensure that the online application and API integrate and automate all Article 27 procedures.	System operator	Governance	Flexibility information system	Requirements for operation of the SP module	This operationalises the provider-side module and can be assessed through whether SP data management, access, notifications, and automation are clearly implemented.
III	26	Art. 26(3)	System operators responsible for operating a CU module shall administer and make available CU data, grant timely access to system users and entitled actors, inform affected actors of Article 28 procedures without undue delay, make relevant CU data changes available without undue delay, and ensure that the online application and API integrate and automate all Article 28 procedures.	System operator	Governance	Flexibility information system	Requirements for operation of the CU module	This operationalises the controllable-unit module and provides clear criteria on access, updates, notifications, and automation.
III	26	Art. 26(4)	Where a third party is entrusted with tasks relevant for operating or maintaining the flexibility information system, it shall have adequate business separation from parties with a commercial interest in local services, and all parties interacting with the modules shall be treated equally and non-discriminatorily.	System operator	Governance	Flexibility information system	Business separation and non-discriminatory treatment for third-party operation	This adds neutrality and conflict-of-interest safeguards where FIS tasks are assigned to third parties.
III	27	Art. 27	SP modules shall provide at least procedures for registration, application, update, suspension, de-registration, grid prequalification, switching, revocation of qualification, and confirmation of SPU or SPG characteristics.	System operator	Governance	Flexibility information system	Minimum procedures in the SP module	This article defines the minimum workflow architecture of the SP module and is central to assessing whether the FIS covers the full service-provider lifecycle.
III	28	Art. 28	CU modules shall provide at least procedures for registration, update, suspension, de-registration, grid prequalification, switching, revocation of access entitlement, termination of assignment, and re-activation of controllable units.	System operator	Governance	Flexibility information system	Minimum procedures in the CU module	This article defines the minimum workflow architecture of the CU module and is central to assessing whether the FIS covers the full controllable-unit lifecycle.
I	2	Art. 2(15)	**'DSO observability area'** means a DSO's own distribution system and parts of other system operators' distribution and transmission systems that the DSO requires information on, to maintain secure operation of its own distribution system	-	Governance	System operator coordination	**Definition**	
VII	45	Art. 45(1)	All system operators of a Member State shall develop a proposal for national terms and conditions for TSO-DSO and DSO-DSO coordination **within 6 months after approval of the national rules of procedure.**	Regulatory authority	Governance	System operator coordination	National terms and conditions for TSO-DSO and DSO-DSO coordination	This creates the formal national basis for coordination arrangements between system operators.
VII	45	Art. 45(2)	The national terms and conditions for coordination shall ensure compatibility with existing TSO-DSO coordination requirements, prevent actions from creating or aggravating congestion or voltage problems on other systems, ensure balancing and local issues are dealt with consistently and efficiently, and support optimal use of available resources to deliver local services at least cost and highest system value.	Regulatory authority	Governance	System operator coordination	Objectives of system operator coordination	This paragraph sets the overall coordination objectives and can be used as a benchmark for whether a case has a coherent national coordination logic.

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
VII	45	Art. 45(3)	The national terms and conditions for coordination shall specify at least the tasks and responsibilities of system operators, the rules for DSO observability areas, forecasting and detecting issues, solving issues, setting and updating grid prequalification status, setting and updating temporary limits, ensuring consistency of trade positions, and coordination-related data exchange and confidentiality requirements.	Regulatory authority	Governance	System operator coordination	Minimum content of national coordination rules	This is the core framework article for system operator coordination and provides the main basis for assessment of whether national or platform rules define coordination procedures comprehensively.
VII	46	Art. 46(1)	Each DSO shall establish its observability area so it can operate its network safely and securely.	System operator	Governance	System operator coordination	Establishment of DSO observability area	This creates a coordination-related observability concept that supports safe network operation and issue detection.
VII	46	Art. 46(3)	The DSO observability area shall include the DSO's own system and relevant parts of other distribution and transmission systems for which the DSO is entitled to receive structural, forecast, schedule and real-time data needed to determine system conditions, solve issues and maintain secure operation.	System operator	Governance	System operator coordination	Scope of the DSO observability area	This provision shows that coordination is not limited to one operator's own grid but depends on visibility into relevant neighbouring systems.
VII	46	Art. 46(4)	When establishing the DSO observability area, the DSO shall transparently involve potentially impacted system operators, determine relevant neighbouring systems and impacted operators in cooperation with them, and the identified impacted operators shall provide the required information and keep it updated.	System operator	Governance	System operator coordination	Coordination process for establishing the observability area	This is a strong coordination requirement because it obliges DSOs and other operators to cooperate in defining visibility and data needs.
VII	46	Art. 46(5)	Each DSO shall establish its observability area **within 6 months after approval of the national coordination terms and conditions**, submit a report to the regulatory authority, and reassess the observability area at least when preparing the distribution network development plan.	System operator	Governance	System operator coordination	Timeline and reassessment of the observability area	This adds implementation and review obligations to the observability-area coordination framework.
VII	46	Art. 46(6)	All relevant system operators shall cooperate in establishing, updating and assessing DSO observability areas and shall exchange the necessary data.	System operator	Governance	System operator coordination	Cooperation on observability areas	This directly requires coordinated observability management across operators.
VII	47	Art. 47(1)	Each DSO shall be responsible for forecasting and detecting physical congestion and voltage issues in its system and for identifying solutions, including analyses for the minimum national timeframes and any additional timeframes defined in coordination with impacted system operators in the observability area.	System operator	Governance	System operator coordination	Forecasting and detection in coordination with impacted operators	This links issue detection to coordination across operators, especially through jointly considered timeframes.
VII	47	Art. 47(2)	Timeframes for forecasting and detection shall be consistent with existing operational-security, day-ahead, intraday and balancing timeframes and shall allow detection as close to real-time as possible.	System operator	Governance	System operator coordination	Consistency of detection timeframes with other market and operational timeframes	This ensures coordination between local operational analysis and broader electricity-market and balancing timelines.
VII	47	Art. 47(4)	Forecasting and detection analyses shall be performed with one-hour or finer granularity for day-ahead, intraday and close-to-real-time horizons and shall use exchanged information on topology, voltage levels, forecasts, schedules and previously awarded bids where applicable.	System operator	Governance	System operator coordination	Inputs and granularity for coordinated system analysis	This gives operational substance to coordination by defining the shared analysis basis for forecasting and detection.
VII	48	Art. 48(1)	Each system operator shall solve physical congestion and voltage issues in its own system, may procure local services from units connected to its own or other systems, shall respect grid prequalification and temporary limits, shall coordinate with connecting and impacted operators and exchange necessary information, and shall apply processes consistent with broader regional operational-security coordination where relevant.	System operator	Governance	System operator coordination	Coordination for solving congestion and voltage issues	This is one of the central coordination articles because it ties local actions to cross-operator coordination, information exchange, and consistency with broader security-coordination processes.

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
VII	48	Art. 48(2)	To contribute to solving issues in other systems, each system operator shall cooperate with the operators of those systems and with procuring system operators to facilitate delivery of local services from units connected to its own system.	System operator	Governance	System operator coordination	Cross-system cooperation to solve issues	This provision requires system operators to support each other beyond their own grids where their resources can help solve external issues.
VII	48	Art. 48(3)	Where unforeseen events affect a selected local-service bid because of constraints in connecting or impacted systems after the temporary-limit communication deadline, the procuring, connecting and impacted system operators shall identify and coordinate solutions, selecting the most cost-effective timely solution under transparent and non-discriminatory rules.	System operator	Governance	System operator coordination	Coordination of solutions after unforeseen constraints	This is a particularly useful assessment criterion because it concerns how operators coordinate when post-selection conflicts arise.
VII	48	Art. 48(4)	Each system operator shall use digital tools, alone or in cooperation with other system operators, to forecast and detect physical congestion and voltage issues, identify solutions, and solve such issues.	System operator	Governance	System operator coordination	Use of digital tools for coordinated system operation	This shows that coordination is expected to be operationally supported by digital tools, not only by manual procedures.
VII	49	Art. 49(1)	Connecting and impacted system operators shall have the right to perform grid prequalification before or in parallel with product qualification processes to ensure service delivery does not compromise safe system operation.	System operator	Governance	System operator coordination	Grid prequalification as a coordination tool	This provision links operator coordination to network-level approval of service provision.
VII	49	Art. 49(3)	Each connecting and impacted system operator shall forecast system status, assess whether service delivery may compromise secure operation, assign one of the grid prequalification statuses, communicate the result through the flexibility information system, automatically approve if no result is communicated in time, and justify conditional or negative outcomes.	System operator	Governance	System operator coordination	Coordinated process for grid prequalification results	This article gives a detailed coordination process for network-level assessment of service provision.
VII	49	Art. 49(4)	System operators may update grid prequalification status when structural grid data changes, system-user data changes, or reassessment criteria are met.	System operator	Governance	System operator coordination	Update of grid prequalification status	This makes coordination dynamic by linking it to changing network and user conditions.
VII	49	Art. 49(6)	System operators shall maximise approved grid prequalification results by using efficient national criteria, focusing on frequent and general scenarios, optimising safety margins, and coordinating efficiently with the temporary-limits process where applicable.	System operator	Governance	System operator coordination	Coordination between grid prequalification and temporary limits	This explicitly requires coordination between two network-security processes instead of treating them separately.
VII	49	Art. 49(8)	System operators shall annually report to the regulatory authority on non-approved or conditionally approved grid prequalification results and the reasons for them.	System operator	Governance	System operator coordination	Reporting on grid prequalification outcomes	This adds accountability to operator coordination and may offer evidence on how restrictive or enabling the coordination framework is in practice.
VII	50	Art. 50(1)	Connecting and impacted system operators shall have the right to set or update temporary limits on system elements, SPUs, SPGs or parts of SPGs in operational planning to ensure service delivery does not compromise safe operation.	System operator	Governance	System operator coordination	Right to set and update temporary limits	This creates a short-term coordination mechanism for protecting system security.
VII	50	Art. 50(2)	Each connecting or impacted system operator shall forecast future system status, identify situations where service provision may compromise safe operation or create issues in connected or impacted systems, and communicate temporary limits to the responsible parties within defined timeframes for balancing and local-service procurement.	System operator	Governance	System operator coordination	Process for setting and communicating temporary limits	This is a core coordination requirement because it defines how operators communicate short-term network constraints into procurement and activation processes.
VII	50	Art. 50(3)	System operators shall minimise the overall market impact of temporary limits by using efficient national criteria, setting limits at broader levels where possible, using accumulated maximum delivery where possible, and optimising safety margins while considering operational limitations.	System operator	Governance	System operator coordination	Minimising the market impact of temporary limits	This provision balances secure operation with market functioning and is useful for assessing whether coordination is overly restrictive.

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
VII	50	Art. 50(4)	The methodology to calculate temporary limits shall be consistent with existing balancing rules and shall be public, transparent, verifiable and accurate.	System operator	Governance	System operator coordination	Methodology requirements for temporary limits	This makes the coordination process around temporary limits more accountable and observable.
VII	51	Art. 51(1)	The activating system operator shall ensure that procurement and activation of local services, activation of flexible connection agreements, or any other action affecting market schedules does not affect the consistency of trade positions in the relevant time window.	System operator	Governance	System operator coordination	Preservation of consistency of trade positions	This links system-operator coordination to maintaining market-trade consistency when local services are activated.
VII	51	Art. 51(2)	Where an action is required, the relevant system operator shall preserve trade-position consistency either by immediate opposite-direction activation for every activation or by netting several activations and performing an overall opposite-direction activation before the relevant gate closure time.	System operator	Governance	System operator coordination	Methods to maintain consistency of trade positions	This defines the coordination actions operators must use to preserve commercial consistency.
VII	51	Art. 51(3)	System operators shall perform these activations in a coordinated way at national level as described in the national coordination terms and conditions; where another approach is justified, they shall publish quarterly information on the resulting activation volumes and balancing prices.	System operator	Governance	System operator coordination	National coordination of activations affecting trade positions	This explicitly requires national-level coordination of activation actions and adds a transparency obligation where alternative approaches are used.
VII	52	Art. 52(1)	Data exchange between system operators shall ensure that each operator has access to the data necessary to determine conditions of its own system, TSOs can assess operational security, coordinated access to resources is not hindered by lack of data, and impacted operators can assess impacts, define and update grid prequalification, and set and update temporary limits.	System operator	Governance	System operator coordination	Coordination-enabled data access between system operators	This is the overarching data-exchange coordination provision and supports almost all other operator-coordination processes in Title VII.
VII	52	Art. 52(3)	Each DSO shall receive information related to its observability area, including structural data, schedule and forecast data, and real-time data.	System operator	Governance	System operator coordination	Data categories for DSO observability and coordination	This defines the main information streams needed for coordinated operation of the DSO observability area.
VII	52	Art. 52(7)	Each system operator shall timely share relevant information on contracted, procured, selected and activated balancing and local services with impacted, connecting and requesting system operators, especially when capacity is contracted and when capacity and energy bids are selected.	System operator	Governance	System operator coordination	Timely sharing of service-related information between operators	This is a direct and observable coordination requirement tied to procurement and activation stages.
VII	52	Art. 52(8)	Data exchanged between system operators shall be limited to necessary and usable data for observability, forecasting and detecting issues, solving issues, setting and applying grid prequalification and temporary limits, and fulfilling the coordination requirements of Article 52, and shall have appropriate and proportionate granularity, timing and periodicity.	System operator	Governance	System operator coordination	Principles for coordination-related data exchange	This sets proportionality and fitness-for-purpose rules for data exchange in coordination processes.
VII	52	Art. 52(9)	All relevant system operators of a Member State shall systematically review, and **at least every two years**, the applicability, scope, granularity, timing and periodicity of coordination-related data exchanges to ensure consistency with advances in local-service procurement and operators' data-use capabilities.	System operator	Governance	System operator coordination	Periodic review of coordination-related data exchange	This adds an adaptive review requirement to coordination-related data exchange.
VII	52	Art. 52(10)	At the request of a relevant system operator, each system operator shall share relevant data provided by service providers with the necessary granularity.	System operator	Governance	System operator coordination	Sharing service-provider data between system operators	This provision closes the coordination loop by allowing operator-to-operator sharing of relevant provider data where needed.

Title	Article	Article / Paragraph	Requirement Summary	Responsible Actor	Main Category	Sub Catetory	Key Aspect	Analytical Insight / Implication
IX	55	Art. 55(1)	**At least once every two years,** ENTSO-E and the EU DSO Entity shall publish a report on demand response covering the previous two calendar years, while respecting confidentiality obligations.	Regulatory authority	Governance	Reporting and monitoring	Biennial demand response report	This establishes a recurring EU-level reporting obligation on demand response and local-service related developments.
IX	55	Art. 55(2)	**The report on demand response** shall include at least information on where market-based procurement of congestion management and voltage control services has been applied or derogated from, the types and volumes of procured products, the procurement methods used, the baselining methods published in the Article 14 register, and an assessment of which baselining methods could be harmonised at European level.	Regulatory authority	Governance	Reporting and monitoring	Minimum content of the demand response report	This is the core substantive reporting requirement and is especially relevant because it links reporting to both local-service procurement and baselining developments.
IX	55	Art. 55(3)	Before the first final report is published, ENTSO-E and the EU DSO Entity shall prepare a draft-report proposal defining the report structure, content and reported data, and submit it to ACER, which may require amendments within two months.	Regulatory authority	Governance	Reporting and monitoring	Draft-report proposal and ACER review	This creates an ex-ante review process for the reporting framework and gives ACER influence over the structure and content of the report.
IX	55	Art. 55(4)	ENTSO-E and the EU DSO Entity shall publish the report online and submit it to ACER **no later than six months after the end of the last year covered**, and ACER may require changes to the structure and content of the next report.	Regulatory authority	Governance	Reporting and monitoring	Publication timeline and ACER follow-up	This sets the reporting timeline and introduces a feedback mechanism for improving future reports.
IX	55	Art. 55(5)	ENTSO-E and the EU DSO Entity shall have access to relevant data from market participants or national flexibility information systems to perform the reporting tasks under this Article.	Regulatory authority	Governance	Reporting and monitoring	Access to data for reporting	This provision ensures that the reporting bodies can obtain the information needed to fulfil their reporting role.
IX	56	Art. 56(1)	ACER shall monitor implementation of the Regulation and regularly publish a European Report focused on monitoring, describing and analysing implementation, including progress on integrating demand response into electricity markets in Europe, while respecting confidentiality obligations.	Regulatory authority	Governance	Reporting and monitoring	ACER monitoring report	This establishes the central EU-level monitoring function for implementation of the Regulation.
IX	56	Art. 56(2)	**Within 12 months after entry into force,** ACER shall draw up and may later update a list of relevant information to be communicated by the EU DSO Entity and ENTSO-E, and the EU DSO Entity and ENTSO-E shall maintain a comprehensive, standardised digital data archive of the information required by ACER.	Regulatory authority	Governance	Reporting and monitoring	Information requirements list and digital archive	This creates a structured information base for ACER monitoring and supports standardisation of reporting inputs.
IX	56	Art. 56(3)	EU DSO Entity and ENTSO-E shall submit to ACER the information required for ACER to perform its monitoring tasks.	Regulatory authority	Governance	Reporting and monitoring	Submission of information to ACER	This provision turns ACER's monitoring mandate into a concrete reporting obligation for the EU DSO Entity and ENTSO-E.
IX	56	Art. 56(4)	Market participants and other relevant organisations for demand-response integration shall submit to ACER, upon request, the information required for monitoring, except where that information has already been obtained by regulatory authorities, EU DSO Entity or ENTSO-E in the context of their monitoring tasks.	Regulatory authority	Governance	Reporting and monitoring	Request-based information provision for monitoring	This extends the monitoring information base beyond central bodies to market participants and relevant organisations, while avoiding duplication where information has already been collected.

B

Interview guides

B.1. French case: academic expert interview guide

The interview followed a semi-structured format. The questions below were prepared in advance. Follow-up probes were adapted during the conversation.

Purpose: To gather an academic expert perspective on France's local flexibility arrangements at the distribution level, with a focus on the role of market-based procurement, market coordination and TSO-DSO coordination.

Theme 1: Role of local flexibility tenders in France

- From your perspective, how would you describe the current role of Enedis local flexibility tenders within the broader French flexibility toolbox?
- Are these tenders a central tool for managing distribution networks, or are they still relatively small compared with tools such as ReFlex, flexible connection arrangements, network planning, and tariff-based instruments?

Theme 2: Why France uses a tender-based model

- The French local flexibility model is mainly based on Enedis tenders and long-term contracts. From your perspective, why has France developed this more tender-based model?
- Is this mainly because distribution grid constraints are local, predictable, and linked to network planning, or is it also related to French institutional and regulatory traditions?

Theme 3: Limited scale of Enedis local flexibility Tenders

- What do you see as the main challenges in scaling local flexibility tenders in France so far?

Theme 4: Flexible connection arrangements and local flexibility tenders

- France has both flexible connection arrangements and Enedis local flexibility tenders. How do you see the relationship between these tools?
- Are they mainly complementary tools, or can they overlap in the same network areas?

Theme 5: Technical challenges for local flexibility

- From a distribution network planning perspective, what are the main technical challenges in using local flexibility effectively?
- For example, how important are location of flexible resources, observability, data availability, and uncertainty in DER behaviour?

Theme 6: TSO-DSO coordination

- How do you see the current coordination between RTE and Enedis in relation to distributed flexibility?

Theme 7: Multi-market participation

- Enedis appears to allow multi-market participation, but with strict rules. From a system operation perspective, are these safeguards sufficient to avoid conflicting activation, or would stronger coordination mechanisms be needed?
- What would be needed to allow more value stacking across different markets while still protecting distribution network security?

B.2. Dutch case: CSP interview guide

The interview followed a semi-structured format. The questions below were prepared in advance. Follow-up probes were adapted during the conversation.

Purpose: To gather a congestion service provider (CSP) perspective on Dutch congestion management, with a focus on GOPACS redispatch, product participation, multi-market coordination, baseline interpretation, delivery verification, and practical barriers.

Theme 1: Practical use of Dutch congestion management products

- From a congestion service provider perspective, which Dutch congestion management products are most relevant in practice: redispatch, mandatory bidding contracts, capacity limitation or steering contracts, or TDTR?
- How do you see the difference between voluntary redispatch and mandatory bidding contracts in practice?

Theme 2: Participation across different markets

- How do you manage the same flexible asset if it can participate in GOPACS and other markets, such as FCR, aFRR, mFRR, or imbalance markets?
- In practice, how do you avoid double use, double activation, or conflicting signals for the same asset?

Theme 3: Baseline or reference point in redispatch

- In GOPACS redispatch, how do you understand the reference point for measuring delivered flexibility?
- Is it based on the asset's original market schedule or market position?
- Is there any separate baseline calculation in redispatch, or is the flexibility volume mainly defined by the accepted buy or sell order?

Theme 4: Delivery verification and rebound effects

- How is delivered flexibility verified in practice after activation?
- Are rebound effects relevant for the assets you work with? If yes, who manages them: the CSP, BRP, asset owner, or another party?

Theme 5: Practical barriers for CSPs

- What are the main practical barriers for CSPs when participating in GOPACS or Dutch congestion management more generally?
- Is the situation improved with the market development?

B.3. Dutch case: TSO interview guide

The interview followed a semi-structured format. The questions below were prepared in advance. Follow-up probes were adapted during the conversation.

Purpose: To gather a TSO perspective on Dutch congestion management, with a focus on redispatch, market coordination, baseline methodology, TSO–DSO coordination, and future NCDR implications.

Theme 1: Congestion management products and their coordination

- From TSO's perspective, how do redispatch, mandatory bidding, capacity steering contracts, and TDTR complement each other in practice?
- How do these products differ in terms of timing, purpose, and activation process?

Theme 2: GOPACS and cross-market coordination

- In GOPACS, cross-platform activation allows bids from different trading platforms to be matched. In practice, can one congestion problem be solved by bids from multiple trading platforms or multiple CSPs?
- How are double use, double activation, or conflicting market positions avoided?

Theme 3: Baseline or reference point in redispatch

- Is it correct to understand that the participant's original market schedule or market position acts as the practical reference point for redispatch?
- From a system operator perspective, would the NCDR require the Netherlands to develop a more formal baseline methodology?

Theme 4: TSO–DSO coordination in congestion forecasting and activation

- How are congestion forecasting, congestion detection, and activation coordinated between TenneT and DSOs in practice?
- How does GOPACS help ensure that solving congestion in one network area does not create new problems elsewhere in the grid?

Theme 5: Grid prequalification and temporary limits

- How does grid prequalification work in practice in the Dutch arrangement?
- Are temporary limits used in practice?

Theme 6: Data exchange between system operators

- What types of data are currently exchanged between TenneT and DSOs for congestion management?
- Do you think the NCDR concept of DSO observability areas could improve congestion management and TSO–DSO coordination in the Netherlands?

Theme 7: Practical barriers and future NCDR implications

- Historical GOPACS data seem to show that TenneT redispatch volumes were especially high around 2021–2023. What could explain this pattern?
- What are the main practical barriers for Dutch congestion management today?
- What changes could the upcoming NCDR bring?

B.4. Cross-case: independent consultant interview guide

The interview followed a semi-structured format. The questions below were prepared in advance. Follow-up probes were adapted during the conversation.

Purpose: To gather an independent consultant perspective on the NCDR, validate the interpretation of baseline methodology in the Dutch case, and obtain a cross-case view on local flexibility market design in France and the Netherlands.

Theme 1: General view on the NCDR

- Before discussing specific market design issues, how do you see the role of the forthcoming Network Code on Demand Response?
- From your perspective, what is the main function of the NCDR for demand response and local flexibility markets in Europe?

Theme 2: Schedule-based baseline in the Dutch redispatch model

- In the Dutch GOPACS redispatch model, my current interpretation is that the asset's market schedule, BRP nomination, or connection-point prognosis can function as a practical baseline. Does this interpretation make sense from a market design perspective?
- Would you describe this as a form of schedule-based or nominal baselining?

Theme 3: Responsibilities for baseline methodology

- From a market design perspective, who should be responsible for developing, implementing, and proposing baseline methodologies?
- Should baseline methods be standardised by the system operator or regulator, or should flexibility providers have room to propose their own methods?

Theme 4: Baseline quality and rebound effects

- The NCDR expects baseline methods to be transparent, accurate, unbiased, and to consider rebound effects. In practice, which of these issues is most difficult to address?
- Can rebound effects be handled through general baseline rules, or do they usually require technology-specific treatment?

Theme 5: Comparing Dutch and French market architectures

- My two cases represent different market architectures. The Dutch case is more market-embedded and redispatch-oriented, while the French Enedis case is more tender-based and planning-oriented. From a market design perspective, do these represent two coherent paths for NCDR implementation?
- What are the main strengths and weaknesses of each model?

Theme 6: NCDR implementation and remaining barriers

- Looking at the NCDR more broadly, which requirements do you expect to be most difficult for Member States to implement in practice?
- Are the main barriers regulatory complexity, market liquidity, baseline methodology, or system operator coordination?