Enabling aggregators to deploy battery capacity for congestion management

Designing a dynamic congestion management framework at Frank Energie

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Designing a dynamic congestion management framework at Frank Energie

By

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Stijn Walsh
Amsterdam, July 2025

Executive summary

Enabling Aggregators to Deploy Battery Capacity for Congestion Management: Designing a Dynamic Congestion Management Framework at Frank Energie is a research that addresses the challenge of integrating residential battery storage into local grid congestion management. The central problem is the conflict between aggregators' use of residential batteries for energy market trading and the reliability needs of the electricity distribution grid. In the Netherlands, companies like Frank Energie aggregate customers' batteries to earn revenues on imbalance markets (trading energy in real-time to balance supply and demand). However, distribution system operators (DSOs) fear that when many batteries charge or discharge simultaneously in response to national price signals, it could overload local transformers and cables. To pre-empt this, DSOs have proposed static restrictions: fixed-hour bans on battery dispatch during peak times. This proposal indiscriminately curtails battery usage. Such blanket measures protect the grid but at a significant cost: they erode the financial viability of residential batteries by reducing opportunities for arbitrage, and they "overshoot" the goal by also blocking battery activity even when and where the grid is not actually congested. This thesis tackles the question of how to avoid this outcome. It seeks a solution that allows aggregators to continue operating batteries profitably while safeguarding local grid capacity, thereby turning the batteries into part of the solution rather than a source of problems.

To investigate this, the research employs a design science and systems approach, structured in five phases corresponding to specific sub-questions. First, a system analysis was conducted to map the interactions between the key electricity markets; the day-ahead wholesale market, the real-time imbalance market, and emerging congestion management mechanisms to pinpoint where aggregator actions may create frictions. This involved a review of the Dutch electricity system's design and roles, as well as semi-structured interviews with industry stakeholders to capture practical insights.
Next, an institutional and regulatory analysis identified how existing roles, responsibilities, and rules (e.g. grid codes, market regulations, and the EU Clean Energy Package provisions) constrain aggregators' participation in congestion management.

In the third phase, the study distilled the technical constraints and stakeholder objectives that any feasible solution must balance. These constraints and goals defined the "design space" for potential solutions.

Guided by this design space, the fourth phase generated several solution concepts that could enable dynamic congestion management. Through synthesis of literature and industry practices, four main approaches were formulated: (1) Distribution-level locational marginal pricing (DLMP), extending real-time price signals to the neighbourhood level to reflect local congestion costs; (2) Local flexibility markets, where DSOs would procure flexibility services from aggregators and prosumers in a dedicated market to alleviate grid constraints; (3) Dynamic network tariffs, which would adjust distribution grid charges based on local congestion risk to influence behaviours; and (4) Dynamic capacity tariffs, where consumers can use the grid to full capacity, but are economically or directly constrained in their allowed capacity during a congestion event.

The fifth phase, evaluates these solution options against the set of criteria that were derived from the earlier analysis of objectives and constraints. These include: effectiveness in reducing overloads, fairness and consumer acceptance, compatibility with current legal/regulatory frameworks, economic efficiency and impact on aggregator revenues, implementation feasibility, and institutional fit with the Dutch market structure.

The research finds that purely static restrictions are a suboptimal response to congestion. A core insight is that the lack of a dynamic coordination mechanism at the local grid level is the root issue. This is essentially a missing market for flexibility in distribution networks.

Among the solution approaches considered, Local Flexibility Markets emerge as the most promising framework for dynamic congestion management. In a local flexibility market, the DSO signals a need for congestion relief at specific times and locations and invites aggregators or prosumers to offer reductions or shifts in load through an auction or bidding process.
The analysis shows that this market-based approach can reliably mitigate local overloads by directly procuring the required flexibility, achieving a High effectiveness in preventing transformer congestion. Unlike blunt restrictions, a local flexibility market targets only the necessary locations and moments, curtailing or providing incentives to battery dispatch precisely when grid stress occurs and allowing normal operation otherwise. This precision avoids unnecessary revenue loss for aggregators and battery owners. Moreover, the local market provides fair compensation for participants' flexibility: when a battery is asked to reduce output or charge at a different time, the owner is paid for that service, aligning private incentives with grid needs. This contrasts with the "no-compensation" nature of outright restrictions.

The thesis further argues that the local flexibility market concept aligns well with regulatory and market trends. It respects the liberalised electricity market structure by using price signals and voluntary participation rather than centralised control. In fact, Dutch and EU energy policies are moving toward market-based solutions for congestion, in the Netherlands this is represented by the already present GOPACS platform. Essentially a local flexibility market for the medium- and high-voltage grid levels.
The evaluation shows that local flexibility markets score strongly on regulatory compatibility and institutional fit: they can be introduced under current frameworks with some extensions and uphold neutrality and transparency standards DSOs are required to strive for by regulators.
By contrast, the other options present greater challenges. A DLMP scheme is economically efficient in theory and could signal congestion costs accurately, but it would represent a radical change in tariff structure and pose fairness issues (neighbourhoods with congested grids would face higher prices continuously) and significant implementation complexity. Dynamic tariffs are easier to implement but less precise. Both alternatives scored lower in either effectiveness or acceptance. In contrast, the local flexibility market approach was assessed as the most balanced solution

The thesis therefore recommends establishing local flexibility markets as the central pillar of a dynamic congestion management framework. This recommended solution turns what was a conflict into a win-win: aggregators like Frank Energie can continue leveraging residential batteries for imbalance and other services, but when the local grid is under strain, they temporarily shift those batteries' operation in response to the local market signal and get paid for helping the grid.

Adopting a dynamic approach to congestion management using local flexibility markets offers a sustainable solution for handling growing electricity demand. By tapping into existing household flexibility, DSOs can manage grid overloads and defer costly infrastructure upgrades, enhancing short- to medium-term resilience with real-time operational tools.
For aggregators, this model avoids revenue loss from static restrictions and opens new income streams by monetizing flexibility, especially from residential batteries and smart appliances. Prosumers gain quicker returns through compensation for supporting the grid, while all consumers benefit from improved reliability and slower tariff increases.
To unlock these benefits, supportive policies are essential. Key recommendations include expanding low-voltage flexibility platforms (similar to GOPACS for neighbourhoods), lowering entry thresholds (e.g., adjusting the 1 MW bid minimum), and improving data-sharing. DSOs must provide near-real-time grid data, and aggregators need to align local dispatch with national market signals. These steps ensure the approach is both technically sound and operationally dependable.

This work bridges a knowledge gap by applying a multi-disciplinary systems engineering approach to a complex socio-technical challenge at the crossroads of energy markets, regulation, and grid technology. It demonstrates how regulatory innovation and market design can keep pace with technological advances.
The thesis offers evidence-based guidance for stakeholders: regulators can adapt frameworks to support emerging flexibility markets while ensuring neutrality and consumer protection; DSOs gain actionable insights on data and operational protocols for piloting flexibility procurement; and aggregators, including companies like Frank Energie, see a clear path to profitability while aiding grid stability.
Ultimately, local flexibility markets emerge as the backbone of dynamic congestion management aligning aggregator incentives with grid needs. The proposed solution lays a foundation for pilot projects and policy refinements that support a more efficient, reliable, and responsive energy system during the energy transition. The work underscores that the right market design can transform a grid challenge into an opportunity.

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1 Introduction

1.1 Societal relevance

The energy transition is accelerating globally and The Netherlands is electrifying at a rapid pace now that global and national goals are in place to reduce carbon dioxide (CO_2) emissions. Delivering Net-Zero in 2050 requires a lot of work, among this electricity networks need to be larger, smarter and repurposed (International Energy Agency [IEA], 2024). Stepping away from fossil fuel for electricity production, in transport, heating and industry puts increasing pressure on our electricity grids (Abousleiman & Scholar, 2015). The Dutch government set the goal for 2030 that 27% of the final energy consumption should be climate neutral (Rijksoverheid, n.d.). While the Dutch electricity grid is already among the most congested in the world, this increases the demand for (clean) electricity even further. Considering the intermittent nature of renewable energy sources (RES) the needed electrification will further drive grid congestion problems if there are no sufficient storage options.
The demand for electricity has been increasing over the past years (Compendium voor de Leefomgeving [CLO], 2024), with people moving away from gas for heating purposes and the increased adoption of electric vehicles. On the supply side the increase in RES such as wind and solar-PV have decentralised power generation. However, the current grid infrastructure is not equipped to handle the fluctuating and unpredictable loads of these renewable sources. Besides the unpredictability of renewable production leading to congestion problems, the grid was built for top-down distribution (Torbaghan et al. 2018). In the past several big power plants (e.g. coal, gas or nuclear) would supply the entire grid top down. In the last 25 years this has changed towards a more decentralised system, decentralised production has taken a larger market share, and more players and roles have entered the market (Howorth & Kockar, 2024). In Figure 1, an overview of the traditional electricity grid is visualised. Figure 2 depicts difference in power flow between the old and new situation. In situation B, power flows from and to households.

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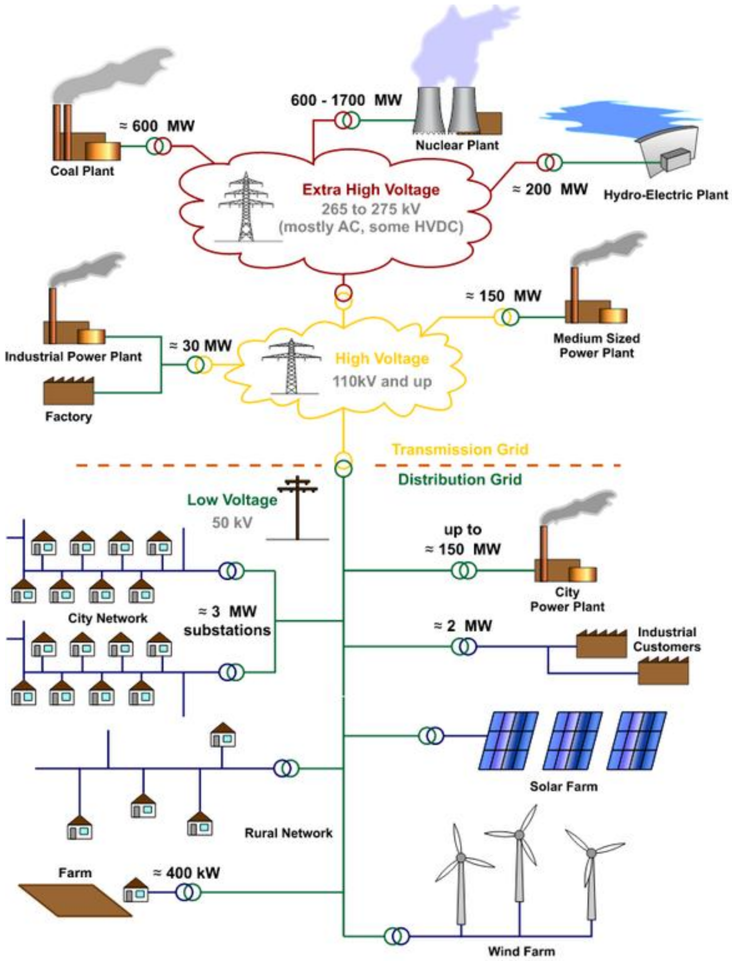

Figure 1: Centralised grid structure with top-down distribution (Energy Education, n.d.).

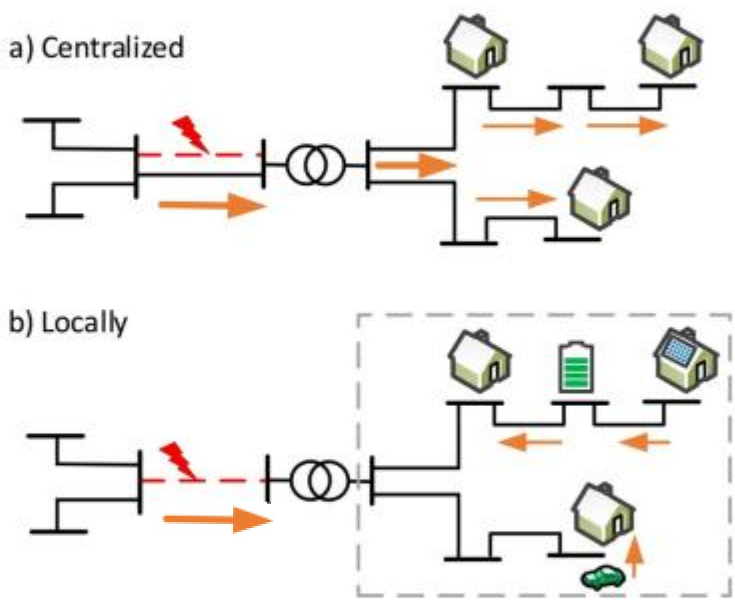

Figure 2: Schematic comparison of the traditional centralised and new decentralised approach in the gird. (Sperstad, Degefa & Kjølle, 2020).

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To facilitate these changes the grid should be expanded, on both the national, high-voltage (HV), and local, low-voltage (LV) level. For the national grid TenneT, the transmission system operator (TSO), has signed contracts for the preparatory works for the expansion of the grid worth a maximum of €2,5 billion over 10 years (TenneT, 2024). Additionally, another contract for the actual expansion works has been signed, worth at maximum €1,75 billion over ten years (TenneT, 2025). On lower grid levels, the distribution system operators (DSO) plan to invest €8 billion annually in their infrastructure over the next ten years (NetbeheerNederland, n.d.). However, these investments take time to realise and even with the planned upgrades, DNV, a Norwegian research agency, estimates that the available transport capacity in 2030 is 28% short of the demand for transport capacity (NetbeheerNederland, 2024).
Furthermore, TNO expects more than half of all existing neighbourhoods to exceed their available transport capacity by 2030 (TNO, 2024). To add to this, the Dutch housing shortage is set to increase even more as newly built neighbourhoods cannot be connected to the grid because of the current congestion (Slob & Bloem, 2023). Similarly, companies cannot electrify their operations because of lacking transport capacity. Because of the long realisation for physical grid upgrades, it is of utmost importance that we're using the available transport capacity in the most efficient way. This calls for new measures to mitigate or solve congestion to ensure security of supply and prevent possible outages. Currently, it is possible for energy suppliers and other market parties to act as an aggregator and provide balancing services to the grid on a national level. Aggregators can not yet act on local congestion markets. Residential batteries present opportunities for congestion management, or at least congestion mitigation, on the low-voltage level.

1.2 Frank Energie

Frank Energie is an innovative Dutch energy company which focusses on offering dynamic energy contracts. In these contracts energy prices are directly connected to wholesale market prices, which are established in the day-ahead market on an hourly basis. This creates an incentive for customers to shift their demand towards cheaper moments. To add additional value to their energy contracts, the company offers services such as smart charging for electric vehicles (EV) and smart trading with residential batteries to its customers. For EV's both the European power exchange (EPEX) price and passive imbalance prices are used to optimise the charging profile, while batteries are solely optimised on passive imbalance signals, disregarding EPEX prices in its (dis)charging behaviour. This way the company offers both a financial opportunity to its customers and actively participates in the management of the grid by offering flexibility to grid operators. Recently, "zelfconsumptie+" (self-consumption+) was launched. This focusses on storing and using generated electricity from solar panels at times when prices and renewable production are low. It only responds to the imbalance signal above a certain threshold. This signifies one more step in becoming self-sufficient and reducing strain on the grid. The next target is to start deploying its contracted batteries on the congestion market.

1.3 Problem statement

Residential battery storage is emerging as a valuable resource in grid management, with companies like Frank Energie aggregating customers' batteries to earn imbalance trading revenues. However, Dutch DSOs have raised concerns that when many such batteries respond simultaneously to national imbalance signals, local low-voltage (LV) grid congestion (especially transformer overloads) could occur. Therefore, restrictions on passive imbalance steering are looming as DSOs perceive residential batteries as a (potential) cause of grid congestion rather than a solution to existing imbalance and congestion challenges (Kooistra, 2024). This has to do with the fact that the amount of batteries responding to such signals are impossible to predict for the DSO. To address this concern and the potential overload of transformer stations, DSOs plan to impose fixed-hour restrictions on imbalance trading, preventing aggregators from activating residential batteries (and other flexible assets) during these periods. These restrictions come at a significant cost: they reduce the number of imbalance hours which are available for trading and significantly impact the financial viability of residential batteries. By reducing the number of hours available for imbalance trading, revenue streams for battery owners decrease, extending payback periods and making residential battery investments less attractive. In a system where consumption at the time of production or storing electricity for later consumption (called self-consumption) is becoming more important, this is undesirable. This one size fits all measure also fails to account for actual real-time grid conditions it would block battery usage even in areas or hours without congestion, an outcome that overshoots the intended goal of protection The restrictions conflict with the aggregator's goal of maximising flexibility and customer value.

From Frank Energie's perspective, residential batteries should not be viewed as a problem, but as part of the solution to grid stability (Frank Energie, 2024). By responding to market signals and leveraging real-time flexibility, these assets can support grid stability while at the same time generating profits for the aggregator and customer. The company therefore seeks to refine the proposed restriction: advocating for a more dynamic approach in which price signals or capacity signals are provided by the DSO at the shortest timeframe possible instead of rigid, fixed-hour limitations. This would allow for optimised battery operation, ensuring both grid stability and minimal revenue loss for customers. Batteries would only be curtailed (or activated) at the specific locations and moments when the local transformer is at risk, and remain free to trade at other times To organise this, insights in congestion data, regulatory constraints, societal feasibility, and DSO capabilities are necessary. The objective is to find a (more) dynamic congestion management approach that allows Frank Energie and other aggregators to deploy residential battery capacity efficiently without endangering grid reliability. The framework should balance technical feasibility, economic viability, and regulatory compliance, ensuring that:

1. Revenue losses from the imbalance market trading restrictions are minimised.
2. DSOs can continue day-to-day operation within the capacity constraints of the grid.
3. Participants receive a fair compensation for their flexibility offer.
4. Regulatory structures are adjusted to accommodate dynamic congestion management.

Fair compensation here means that battery owners or aggregators should be renumerated in line with the economic value of their flexibility and the revenue losses they might incur due to the DSO-imposed restrictions.

Dynamic congestion management refers to the real-time or near real time coordination of electricity consumption, production or storage in response to location- and time-specific grid conditions. Unlike static measures, which impose fixed limitations regardless of actual grid conditions.

It can be argued that is not desirable to have residential batteries act on low-voltage grid levels and instead have industrial sized batteries organise this on the medium- and high-voltage levels. Residential batteries provide congestion relief exactly at the low-voltage nodes where transformer overloads occur, something large-scale batteries at higher voltage levels cannot do because they operate upstream of the bottleneck (Luthander, Widén & Palm, 2015). They also enable a more distributed and resilient flexibility portfolio, lowering reliance on single large assets and the potential problems if one asset fails.

1.4 Market interactions

The electricity market has multiple layers and behaviours influencing each other. Below I shortly introduce the three main layers of the Dutch system followed by observed behaviour in the markets from the view of different parties. The points of view are, in part, deducted from conducted interviews with stakeholders.

1.4.1 The day-ahead-, imbalance-, and congestion market

The problem statement introduces multiple markets, the passive imbalance and the congestion markets. These are (a part of) the second and third market layer in the Dutch electricity system behind the day-ahead market. While all three markets are distinct and serve their own purpose all layers interact with and influence each other. Understanding their impact on the grid is important for analysing the problem and coming up with suggestions for the future.

The day-ahead market provides the initial planning of supply and demand, and as the name suggests is cleared one day in advance. Price-setting in the day-ahead market is done via the merit order principle, where the highest prices agreed upon sets the price for the whole market. A party which buys on the day-ahead market is a balance responsible party (BRP) and needs to ensure that they consume or feed-in the exact amount of power which they had initially projected on the day-ahead market. Failing to do so causes the system to be out of balance. Of course, the forecasts will deviate from the real-world production and consumption behaviour. This is where the imbalance and intra-day markets come into play. First, after the day-ahead market is cleared BRPs have the opportunity to rebalance their portfolio in the intra-day market. This is done through over-the-counter (OTC) trading of electricity volumes and can be used up to 5 minutes before delivery. The day-ahead and intra-day market (together with the long-term market) make up the ‘spot markets’.

Any misalignment after the scheduling markets is resolved in the imbalance market. In this market, BRPs are financially incentivised to correct their forecast errors in real time, often by steering flexible assets like residential batteries. When supply exceeds demand or vice versa, it can lead to instability or even failure of the grid, with all its consequences. The system operator then issues a signal indicating the need for either more generation or demand reduction to bring the system back into balance. Market participants respond to these signals by offering or accepting imbalances. This can involve adjusting their energy production or consumption levels. The prices in the imbalance market can fluctuate significantly and can spike much higher than day-ahead prices.

At the moment of delivery, the congestion market addresses a different issue: (local) physical limitations of the distribution grid. Congestion occurs when electricity flows exceed the transport capacity of cables or transformers, especially on the LV-grid. Although these markets were designed to tackle separate challenges, they increasingly overlap and interact. For example, batteries may be steered by national imbalance price signals, but disregard local grid conditions, potentially worsening congestion at specific LV transformers. Also, as more consumers adopt dynamic contracts and public EV charging stations start following wholesale market prices, variability in day-ahead prices can put a serious load on a transformer. While traditionally congestion was defined and managed ex ante, based on the expected capacity exceedance (e.g. forecasted transformer overloads), recent developments increasingly involve near-real-time management. For example, GOPACS enables DSOs to resolve expected or actual congestion on a day-ahead or intraday basis, but not yet at the sub-hourly level of the imbalance market. Therefore, the congestion market currently operates on a semi-dynamic timeframe: it aims to prevent physical overloads with some lead time, but still lacks the full temporal responsiveness of the imbalance market.

The growing interdependence between these markets introduces significant complexity and calls for better alignment of market behaviour. The dynamics are further explored in Chapter 3, which examines the current system structure and design implications for congestion friendly implementation of residential batteries.

1.4.2 Market behaviour

A multitude of stakeholders and behavioural types can be identified in the electricity markets. All with their own objectives, incentives and effect on the market. DSOs are responsible for ensuring reliable and secure operation of local electricity networks. Facing increasing grid congestion, they typically act conservatively, focusing on grid stability and reliability. Hence, they propose to restrict battery trading in certain hours, as they view this as a potential risk to their operations. Conversely, aggregators have the intention to maximise their welfare through imbalance trading. This is to be expected with the price incentives on the imbalance trading and fits into neoclassical economics (Reisch & Zhao, 2017). Their operation of residential batteries follows a rational strategy of wealth maximalisation. The same goes for customers, through rational behaviour neoclassical economics expects them to seek cost efficiency, reliability, and sustainability, something at least part of the customers do. They engage in energy markets primarily to reduce electricity bills or maximise returns on investments like residential batteries.

We could argue that market failure is present here. Both consumers and aggregators are acting rationally according to neoclassical economics. With the provided price signals, the TSO and DSOs hope that market parties react in the imbalance market, yet the DSO now worry that these reactions will overload the distribution grid.

1.5 Knowledge gap

The previously discussed sections introduce the problem statement as seen by Frank Energie, the complexity of the interaction of the different electricity markets, and behavioural patterns. However, a critical knowledge gap remains concerning the organisation, regulation, and technical conditions for optimal participation of aggregators in grid management through residential batteries. While residential batteries have considerable potential for providing both supply- and demand-side flexibility, current practises are focussed primarily on financial optimisation through imbalance trading and can inadvertently exacerbate local grid congestion. Existing imbalance steering mechanisms do not consider local grid constraints, creating a conflict between the interests of the TSO, DSOs and aggregators.

Given the rapid growth in residential battery installation in the Netherlands (Van Gaalen, 2024), as indicated by the increasing adoption rates, it is clear that their potential for congestion management remains underutilised. At present, the absence of a structured market framework, clear compensation models, and extensive data-sharing possibilities prevent aggregators from optimal deployment of residential batteries. For a combination of financial and congestion-relief purposes. Moreover, the absence of comprehensive, real-time congestion data at the transformer-level, along with the inability to forecast or convey local grid conditions, hinders the execution of genuinely dynamic congestion management strategies. It is clear that a fundamental gap exists as to how aggregators, DSOs and regulators together can best organise an dynamic, transparent, and efficient congestion management framework.
This thesis aims to bridge the identified knowledge gap and enable aggregators to continue their activities on the imbalance markets. By developing a regulatory and market framework that enables aggregators to deploy residential batteries for congestion management, ensuring technical feasibility, economic viability, and regulatory compliance. The main research question therefore is:

How can aggregators, such as Frank Energie, minimise revenue losses from DSO-imposed imbalance trading restrictions through a data-driven congestion management approach while at the same time mitigating congestion?

1.5.1 Research questions

To answer the main research question in a systematic way, four sub questions have been created to guide the research. These are presented and further addressed below.

1. How do the day-ahead-, imbalance- and congestion markets interact and influence each other?

This first question aims to understand the complexity that exists in the design and operations of the Dutch electricity system. To fully understand where problems arise because of imbalance steering the interconnectedness of the markets needs to be understood.

2. How do current actor roles, responsibilities, and regulatory constraints influence aggregator participation in congestion management?

This sub-question explores how the roles, responsibilities, and regulatory boundaries of key system actors shape the ability of aggregators to engage in congestion management. Understanding these institutional structures is essential, as they influence who can act, when, and under what constraints. Without this context, proposed solutions may conflict with current market roles or legal obligations.

3. What system-level constraints and stakeholder objectives define the design space for a dynamic congestion management approach?

This question focuses on identifying the system-level constraints and stakeholder objectives that define the limits of feasible solutions. To ensure that any dynamic congestion management approach is realistic, it must align with both technical capabilities and institutional expectations. Mapping these factors helps narrow the solution space to what is implementable in practice.

4. What solution options can be developed within the design space based on the systems constraints and stakeholder objectives?

This sub-question focuses on identifying possible solution directions that emerge from the previously defined constraints and objectives. By exploring what can be developed within these boundaries, it becomes possible to outline a set of realistic, context-aware options for dynamic congestion management. This step is essential for bridging the gap between system analysis and actionable design.

5. Which solution directions best fit the defined design space, based on regulatory, operational, and stakeholder-alignment criteria?

This sub-question builds on the defined design space by evaluating which solution directions offer the strongest fit based on a set of qualitative criteria. It aims to compare potential approaches in terms of feasibility, regulatory compatibility, and stakeholder alignment. This helps determine which options best support aggregators while addressing congestion challenges.

1.6 Link with CoSEM master program

In this thesis the dynamics of congestion management in the complex electricity network are researched. The complexity of managing grid congestion in a ever more decentralising energy system is a quintessential example of a "complex system". The interplay of technological, economic, and regulatory factors must be balanced. The holistic approach of this thesis fits well within the masters programme. Multiple levels and stakeholders of the electricity system are considered. The goal of the research is to establish rules and propose adjustment to the current system that can serve the deployment of residential batteries to solve local congestion problems. The dynamics of such an issue are exemplary for the CoSEM program. In the research my multidisciplinary education will be useful for analysing the problem from both a technical, policy and social perspective. Systems thinking and stakeholder management are invaluable in exploring viable solutions to the problem. This involves combining technical capabilities of our current infrastructure with regulatory compliance and price signals.

1.7 Report outline

Chapter 1 describes the context and societal relevance of residential battery aggregation in congestion management, it introduces Frank Energie and defines the problem statement which arises from the DSOs' static imbalance restrictions. The problem statement sets the stage for the rest of the thesis. After the problem statement, the knowledge gap, identified in scientific literature and in interviews with market experts is presented along with the research questions. I have opted to present the sub-questions in the introduction to

Chapter 2, “Literature review”, provides the foundation for understanding, analysing, and interpreting the research problem. It consists of two parts, where first the main concepts and the state-of-the-art in congestion management practices are introduced followed by three theoretical frameworks to use in the analysis of the system. For example, principles from neoclassical economics are discussed to understand stakeholder behaviour. The chapter also discovers the concept of regulatory overshooting and related literature, explaining how overly rigid regulations lead to inefficiencies. This justifies a more dynamic approach to the problem.

Chapter 3 details the research approach, which follows a design science and systems engineering methodology. It outlines the multi-phase design process used to identify, develop, and evaluate congestion management solutions. Methods for data collection are described as well as the data management plan.

Chapter 4, “System Structure”, provides an overview the current configuration of market parties and roles within the Dutch electricity system. The complexity of the three electricity markets (day-ahead, imbalance and congestion) and their interactions are explored. It reviews how congestion is managed today (mostly high/medium-voltage) and identifies the shortcomings in the low-voltage context that motivated the DSOs’ proposed restrictions. The analysis clarifies where aggregators’ operations create tension in the absence of a coordination mechanism and answers the first sub-question.

Based on findings from Chapter 4, Chapter 5 explores the objectives and constraints that the solution should respect and satisfy. The chapter does so by taking the point of view of different parties into account.

Chapter 6 presents the design space. Here all variables that can be adjusted to meet the objectives and constraints from chapter 5 are discussed. It sets the stage for what the solutions can look like. This chapter integrates the findings from earlier chapters to define the design space within which viable solutions can operate. It identifies key trade-offs, such as between reliability and aggregator autonomy, and sets out the conditions any solution must meet in terms of institutional fit, technical feasibility, and stakeholder alignment.

Chapter 7 discussed the four solution options extensively: distribution-level locational marginal pricing (DLMP), local flexibility markets, dynamic tariffs adjustments, and dynamic capacity tariffs. Each is assessed against predefined criteria, including effectiveness, fairness, and compatibility with regulatory frameworks. Local flexibility markets are found to offer the most balanced and practical solution.

Chapter 8, the discussion reflects on the implications of the evaluation results, linking them back to the literature and theoretical frameworks. It explores the feasibility of implementation, broader system impacts, and stakeholder roles. Key limitations and areas for improvement are also discussed.

Finally, the conclusion in Chapter 9 summarises the research outcomes and provides an answer to the main research question. Future research directions and policy recommendations are also presented. This is followed by Chapter 10, a small reflection on my own process.

2 Literature review

This literature review consists of two parts, both contributing to the understanding of this thesis. First the most important technical concepts and approaches regarding grid congestion (management) are reviewed. The starting point is a clarification of the core concepts, terms that are used repeatedly in the report and must be unambiguously understood by the reader. Then a description of congestion management approaches which have been tested or simulated and are deemed effective by scientific literature is presented. This is followed by several theoretical frameworks on which to build the analysis in the later chapters. Here, the (expected) behaviour of market participants is explored through the lenses of the framework.

2.1 Core concepts

Grid congestion – Grid congestion occurs when the demand for electricity transport exceeds the transport capacity of the electricity network, leading to bottlenecks and delays in energy distribution. For transformer stations, congestion can be endured for longer time periods before blackouts occur. However, for meters, cables or fuses short term peaks are more problematic (CE Delft, 2025). It is a critical issue in the energy transition, as electrification and decentralisation increase the strain on existing infrastructure. The current grid is not designed for decentralised and highly variable loads.

Aggregator – An aggregator is: ''Someone or something that gathers together materials from a variety of sources.'' (Merriam-Webster, n.d.). In the energy markets, specifically with residential batteries, an energy supplier can act as aggregator of the customers in their portfolio. The combined capacity can then be offered in one bid on the wholesale market in one of the different balancing roles (TenneT, n.d.). These roles are balance responsible party (BRP) and balance service provider (BSP). An aggregator cannot yet act as a congestion service provider (CSP), which is what this research will aim to achieve. When the aggregator bundles multiple residential batteries they can achieve a significant impact in the market. Something which is not possible for one single household.

Flexibility markets – Flexibility markets are mechanics which enable energy consumers, producers or storage providers to trade flexibility to help stabilise the grid and manage congestion. In most situations, the flexibility is bought by the TSO or DSO. Large consumers like a factory, distribution centre or aggregators offer their flexibility to the TSO or DSO to help them balance supply and demand. Flexibility markets have gotten increasingly more important over the past years as electricity production has become more decentralised.

Residential energy storage systems (RESS) – RESS or residential batteries store electricity generated for later use. They are the primary assets that the aggregator will leverage in congestion management. Because of their fixed nature they offer more possibilities than EV's despite their smaller capacity. The TSO or DSO's can contract the always available capacity easily through the aggregator. This ensures the TSO or DSO of a fixed level of available flexibility at any time.

Transformer station – Transformer stations are a key component of the electricity grid where voltage levels are adjusted to enable efficient power transmission and safe distribution. HV-electricity from power plants is 'lowered down' using transformers so that it can be safely distributed to homes and small businesses. These stations help regulate and route electricity.

Depending on their location and function, they either increase voltage for long-distance transmission or decrease it for local distribution.

2.2 State-of-the-art in congestion management

The rapid transition to renewable energy, characterised by intermittent and decentralised generation, has led to significant mismatches between energy supply and demand. Peaks in RE production often coincide with grid congestion due to insufficient transmission and distribution capacity (Van den Boom, 2023; Khomami et al., 2020). Additionally, high adoption of capacity demanding technologies such as heat pumps and EVs put stress on the low voltage (LV) grid (Brinkel et al., 2022). According to Norouzi et al. (2023): ''these problems challenge the operation of electricity grids to reconsider all parts of the supply chain, not just generation.'' TSOs and DSOs need effective methods to manage the increased capacity demand and maintain grid voltage at the desired level. An upgrade of the grid presents itself as the obvious solution, but this takes time. Flexibility options can (partly) provide an efficient alternative solution to grid expansion (Jafarian, 2020). As estimated in the ''Schakelen naar de toekomst'' (English: switch to the future) report (Rijksoverheid, 2025) the cumulative investment cost, for total electrification, are €195 billion, of which nearly half is expected to be off-shore. The report estimates that more efficient grid usage could reduce the cumulative investments by as much as €41 billion, a number worth pursuing.
In the following paragraphs I first introduce the current (or previous) approach in The Netherlands, USA, and the Nordics. Then GOPACS, the current approach for congestion management is touched on, followed by three potentially promising options for a more dynamic approach utilising smaller connections. At this moment a multitude of flexibility options are developed, working at different grid levels, but these are not interoperable (McCulloch, 2023). Nor are they all being put to use in the Dutch electricity grid and its congestion management.

2.2.1 Current congestion management

The traditional approach to congestion in the Dutch electricity system relied on network expansion and predict-and-provide strategies, assuming demand could always be met by reinforcing infrastructure. However, with rising grid constraints, especially in LV- and MV-grids, this strategy alone has proven insufficient. When structural congestion congestion is looming, the Netcode Elektriciteit states that a DSO has the obligation to solve the capacity problem against the lowest possible societal costs (CE Delft, 2025).
TenneT and DSOs have adopted temporary congestion management schemes to cope with both feed-in and off-take congestion. The core elements of current practices in the Netherlands include:

- **Redispatching agreements**: Market parties voluntarily curtail or shift consumption/generation in exchange for financial compensation, typically activated under a "last resort" framework. This is organised in the GOPACS platform for the MV- and HV-grid, elaborated on in section 2.2.2.
- **Congestion studies**: Obligatory studies conducted prior to rejecting new connection requests. These assess whether congestion management can be a viable alternative to grid reinforcement.

- **Contracts with flexible assets**: DSOs procure flexibility (e.g., from batteries or large industrial loads) to locally resolve congestion. These assets respond to activation signals via pilot platforms or bilateral arrangements.
- **Priority rules:** New connection requests are handled based on standardised queueing rules, the party that is waiting the longest will be connected first. Unless, new applicants can offer flexible operations, also known as non-firm access. Non-firm access refers to a type of grid connection agreement where a user is connected to the electricity network without being guaranteed unrestricted access at all times. Instead, the user agrees to certain limitations typically during periods of grid congestion.

While the Netherlands is still in the early stages of building a cohesive and scalable congestion management system. There is an abundance of international experience and academic literature that offers direction.

One of the most widely studied methods is Locational Marginal Pricing (LMP), used extensively in the US by SOs like PJM and CAISO. LMP reflects the cost of delivering electricity at specific locations, or nodes, accounting for both generation costs and grid congestion. As a result, it provides highly granular price signals that naturally incentivize generators, consumers, and storage providers to act in ways that alleviate congestion (Pollitt, 2023). Each node, 10,251 for PJM, has a different price, that changes every 5 minutes. Not all parties using the system deal with nodal prices, only larger loads are exposed to full nodal prices and other connections are subject to some form of averaged nodal price across a wider zone. Although implementing LMP in Europe poses regulatory and political challenges, its effectiveness in aligning economic behaviour with physical grid limits remains compelling.
The Nordic countries have adopted zonal congestion management systems, combining multiple bidding zones with active redispatch of generation. If the initial market clearing leads to an overload on transmission lines between predefined bidding zones, the market is "split." The price difference between zones incentivises producers in the low-price area to reduce output and those in the high-price area to increase output, thereby alleviating congestion across the zonal boundaries through market forces (Bjørndal, Bjørndal, & Gribkosvskaia, 2013).
A wide range of algorithmic and techniques have been proposed for more active congestion management, including genetic algorithms, particle swarm optimization, and fuzzy logic controllers (Pillay et al. 2025). These methods are particularly useful in complex, multi-objective environments where grid operators must balance economic efficiency, reliability, and operational constraints. Although many of these tools remain at the pilot or simulation stage, they hold considerable promise for future integration into congestion forecasting and control systems. Some options to balance more variables follow below section 2.2.2.

2.2.2 GOPACS

Grid Operators Platform for Congestion Solutions, GOPACS, is the central platform currently used in the Netherlands to manage congestion in a market-based, coordinated manner (GOPACS, n.d.). It primarily operates on the MV- and HV-level grids, where congestion is most visible and metered in detail. When a DSO expects congestion on a specific part of the grid, based on forecasts, it issues a flexibility request via GOPACS. Market participants with large connections (> 1 MW), can then submit their bids to reduce or shift consumption or production during that timeframe. GOPACS matches these bids with counter-bids from non-congested zones to maintain balance in the system. This results in preventive redispatch, typically conducted day-ahead or intraday as previously mentioned. While GOPACS does not yet operate at the LV-level grid, due to several limitation such as metering, data and asset size, it reflects a shift towards a more flexibility based approach for congestion management. Instead of relying on grid reinforcements or static curtailment measures.

2.2.3 EVs and congestion management

Several mechanisms to combat grid congestion have been identified through the use of EVs. This follows logically from the fact that EVs are one of the most capacity demanding technologies on the current electricity grid. Proposed by Brinkel et al. (2022) is the use of shared EVs. DSOs should contract car-sharing platforms to manage the charging of shared EVs. These vehicles are employed to shift charging to off-peak hours or even discharge energy during peak demand: vehicle-to-grid (V2G). V2G, while receiving a lot of attention, is still a mostly theoretical technology and underdeveloped. Shared EVs show to alleviate all congestion problems in 400 kVA transformers with relatively low adoption rates (Brinkel et al., 2022). The increased predictability of shared EVs availability over private EVs has greater utility for the grid operator, this predictability mirrors that of residential batteries. Yu et al. (2022) found that uncontrolled charging worsens grid congestion. They suggested three methods in their paper to lower grid congestion of which two were successful: The voltage droop method (VDM) and average rate method (ARM). A dynamic grid tariff system for EV chargers has also been proven effective, showcasing a 21% reduction in transformer congestion (Brinkel et al., 2023). A comparison between EVs and batteries can be drawn here. EV chargers in neighbourhoods in the Netherlands typically put out 3,6 kW or 11 kW of power (ANWB, n.d.), while the batteries sold via Frank Energie range from 2,2 kW to 15 kW (Frank Energie, n.d.). With the power capacity being similar, it could be argued that similar results should be obtainable.

2.2.4 Batteries and congestion management

Batteries and other energy storage systems are seen as a key tool to manage grid congestion (van den Boom, 2023). Yet, in the current situation battery storage systems could worsen congestion instead of alleviating it if they're operated solely for profit (e.g. trading on EPEX or balancing market). Besides, a stalemate exists; Van den Boom (2023) identified that without trading in these markets makes for an unattractive investment opportunity, which in turn causes people to abstain from investing in a battery. Public investments by DSOs and TSOs in battery storage is similarly unlikely, as DSOs and TSOs are prevented from owning and operating batteries directly by EU unbundling rules. Shared ownership of batteries between DSOs (made possible by the exemption in EU Directive 2019/944) and third parties could provide a solution to both the investment gap and the congestion reinforcing potential of batteries (Van den Boom, 2023). Argiolas et al. (2022) show that battery energy storage systems (BESS) can reduce peak loads and mitigate congestion at a fast charging station for EVs. The DSO benefits from this peak shaving and reduced congestion. Additionally, it reduced the need for higher capacity in a connection, enabling more connected entities to the grid and lowering grid connection fees for users. Lastly, the combination with PV installations shows a decrease in the payback period for the battery.

2.2.5 Aggregation and congestion

Aggregators bundle the individual consumption and production of their customers to act as one entity in the energy markets. Brinkel et al. (2021) & Khaksari et al. (2024) found that

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aggregators can mitigate grid congestion if they consider grid constraints in their optimisation process. Day-ahead forecasting of grid load is important here, so that aggregators can consider peak congestion moments in their market bids for consumption or (PV) production. Of course, in real time congestion could occur when the transformer load exceeds the forecasted loads. Still, only optimising aggregator consumption for market price will further worsen congestion, which is something we've seen in Utrecht in the past year (Kooistra, 2024). Distributed locational marginal pricing (DLMP) could be one way to integrate congestion into forecasted electricity prices. The DLMP, received from the DSO, takes the market price and adds the costs of losses, and the costs of congestion at a given location in the distribution grid (Almeida et al., 2021). The aggregator then incentivises their customers to shift their demand for transportation to less congested times and pays them for the demand response (DR). While the introduction of DLMP diminishes the economic performance of the aggregator it greatly enhances the performance of the grid (Almeida et al., 2021).
As of now the congestion market is not (yet) organised the same way aggregators are being paid for balancing services (TenneT, n.d.). Kara et al. (2022) also call for the creation of (local) market mechanisms for congestion on which the aggregator can act. In their version the aggregator offers flexibility on the low voltage grid to a DSO which it buys to mitigate congestion. Both Kara et al. (2022) and Khaksari et al. (2024) call for future exploration of dynamic pricing and locational optimisation in congestion management. The report by CE Delft (2025), written on instructions from the DSOs, also calls for the DSOs to obtain further insights in the locational an time aspects of congestion occurrence. Unfortunately, the current grid configuration in the Netherlands does not allow for such signals (Hulshof, personal communication, 2025).

2.3 Theoretical frameworks

This section examines theoretical frameworks that provide lenses to analyse the behaviour and interactions of key stakeholders in the Dutch electricity system and local congestion problems, notably the DSOs, consumers and aggregators. A theoretical framework is critical in providing a foundation for understanding, analysing and interpreting the research problem and the to be designed solution. It links the research with existing knowledge and in doing so ensures scientific rigor. Several frameworks are addressed and will form the basis for the system analysis later on the research.

2.3.1 Neoclassical economics

Neoclassical economics serves as a foundational theory for understanding market dynamics consumer behaviour, and pricing mechanisms in markets such as a competitive energy market. It provides a foundational model of how markets and participants are expected to operate in under ideal conditions. Neoclassical economics is so deeply rooted and essentially the "default" economic theory that it is almost synonymous with the term ''economics" (Mueller, 2004). Economic agents, firms and consumers alike, are expected to act rationally to maximise profit and utility respectively (Reisch & Zhao, 2017; Corporate finance institute, 2024). This perspective assumes that markets will move towards equilibrium through price action, where supply and demand interact and eventually meet (Marhsall, 1890). In the context of this research, neoclassical properties suggest that aggregators and their single consumers will respond in a predictable way to price signals. The lack of a current market structure where supply and demand for congestion services interacts does not fit the description of a 'perfect market' in neoclassical theory. The occurrence of losses of revenue because of congestion signals may lead to consumers withdrawing their batteries from the aggregator as a whole, if other options yield better results.

DSO behaviour

Dutch DSOs are publicly owned and regulated companies and can not be privatised, this is mandated by the Elektriciteitswet 1998, article 93.4 (Overheid.nl, 2025). According to neoclassical economics there is a difference in the objectives of private and public companies. Traditionally, it is believed that public companies lack the profit-incentives of private companies, potentially leading to inefficiencies. Without the pressure of market competition, public companies might not prioritise cost minimisation or innovation to the extent that private companies do. The opposite has been true in the Netherlands, DSOs have been overly prioritising cost minimisation and affordability for consumers at levels that have hindered investments in and expansion of the grid (Nieuwsuur, 2022; Wetenschappelijke raad voor het regeringsbeleid [WRR], 2008). Nieuwsuur notes that the Autoriteit Consument & Markt (ACM), the Dutch energy market overseer, has been too strict on the budget and profit margins of DSOs. This left the DSOs with their focus on short term cost rather than long term goals. All while the WRR report (2008) already identified that long-term investments in critical infrastructure are instrumental to ensure future prosperity.

Consumer behaviour

An important assumption in neoclassical economics is utility maximalisation, where entities make decisions to give them the greatest economic benefit (Reisch & Zhao, 2017). Applying this to residential battery owners suggests that they will choose to charge their batteries during low prices (EPEX or imbalance price does not matter here) and discharge when the prices are high. This minimises electricity costs and maximises their utility from participating in the market, which is the ultimate goal (Stigler, 1961).
Empirical evidence supports this notion. As studies on time-of-use pricing demonstrate that consumers shift their electricity consumption away from high-price hours (Faruqui & Sergici, 2010). This resonates within Frank Energie, as their proposition for imbalance trading with batteries generates significant revenues for the customer, attracting battery owners at a rapid pace (Frank Energie, internal data, 2025). For individual actors this would require constant monitoring and adjustments, while being connected to an aggregator which manages this for the actor automates the behaviour. Traditional mentions of price elasticity don't apply here, as it is a one time decision to start (or stop) with smart trading, therefore not requiring behavioural adjustments each time price arbitrage occurs. Besides, electricity demand is only partly elastic, as appliances such as a refrigerators use power constantly. The battery does provide elasticity options during high prices however.

If future congestion pricing mechanisms reflect real-time grid constraints, rational consumers, or in this case the aggregator, should naturally adjust their battery charge and discharge behaviour to reduce peak congestion and improve overall system efficiency. The passive imbalance market works in a similar way. Applied to the Dutch electricity system, an effective congestion pricing framework should, in theory, result in cost-effective congestion relief, where aggregators strategically deploy batteries based on price fluctuations. It should also drive customers towards aggregators which can optimise their utility.

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Aggregator behaviour

Aggregators, among them Frank Energie, follow neoclassical economics closely in their behaviour in the electricity markets. As described in Reisch & Zhao (2017) they intend to maximise their profitability by responding to all types of market/price signals. Of course, aggregators need to operate withing the boundaries of both the technical and institutional system. The unhappy response to the proposed restrictions also fits the neoclassical framework. Aggregators align with the ideas of Marshall (1890) that price action in a market will lead to an equilibrium of supply and demand. In line with neoclassical expectations, Frank Energie has introduced new trading markets to their residential battery steering software in April 2025 (Frank Energie, 2025). This is to ensure the most optimal results are still obtained, and performance remains better than that of competitors.

Challenges to neoclassical economics

The neoclassic ideal rests on strong assumptions that often do not hold in electricity markets. Stigler (1961) emphasises the importance of equal information in efficient market behaviour, thus calling for price signals to be transparent for customers and aggregators alike. In practice, home battery owners often lack real-time access to grid congestion data, which may hinder their ability to make optimal decisions. This critique is partly mitigated by the fact that the aggregator makes the moment-to-moment decisions, through the designed algorithm which optimises for financial results. Whereas the customer only decides whether or not he/she will have his/her residential battery participating in the actions of the aggregator.
Secondly, neoclassical economics assume zero transaction costs, whereas aggregators incur significant barriers to entry, compliance and operational costs, meaning not everyone who could provide flexibility will find it worthwhile (Stigler, 1961). However, when the impact of an aggregator is considered on the congestion market, it could be argued that it is beneficial that several larger parties participate rather than countless small ones. Besides the aggregator, the customer also incurs costs in searching for the right supplier to cater to their needs. However, as an energy supplier must me selected regardless of joining an aggregator with a residential battery, the additional transaction cost are only marginal.
Lastly, it assumes that no party has the ability to influence the market price (no market-power). This could be challenged when local congestion markets are designed. Should there be an aggregator with enough assets to create congestion problems locally, they could drive up the price and extract high payments from DSOs to solve the congestion.

That being said, neoclassical economics is extremely useful as a baseline: it highlights the power of price-based coordination and the expectation of rational reaction. For this study, neoclassical theory sets the expectation that aggregators and consumers will respond to in a predictable way to price signals. This entails that a well-designed dynamic congestion pricing scheme, in theory, should lead to efficient outcomes.

2.3.2 Market failure theory

The principle of market failure extends neoclassical theory by addressing the limitations of real-world markets. Where neoclassical theory focusses on how ideal markets should function, market failure theory explores why real markets often deviate from the ideal. In particular, it accounts for situations where price signals fail to reflect the full social cost or benefit of an action, leading to economically inefficient outcomes (Oxford Scholastica, 2025). They justify potential interventions in the free market.

Electricity markets have several sources of failure that are inherent to its nature. Electricity markets are a classic natural monopoly (Künneke, 1999): it is most efficient for one single firm to operate the wires network in a region, in the same way that it is most efficient for one railway company to build railways. The reason; high fixed cost and economies of scale. A monopoly requires regulation to ensure that market power is not abused. In this specific situation it lead to an under-supply of network capacity, as the regulatory body was too focussed on cost-saving as previously discussed.
Second, is the presence of negative externalities. The coordination externality is a relevant externality in congestion management: the actions of one aggregator (such as extensive battery charging) may result in costs (stress) to the local grid that are not represented in any price that the aggregator pays under current tariff structures. Because the aggregator's optimum, charging when energy is cheap, differs from the social optimum, which would take into account the costs of the distribution network for simultaneous charging, this is a market failure. Conversely, if the aggregator mitigates or solves grid congestion, they're don't receive a renumeration. This gives them no incentive to change their current behaviour.
Lastly, asymmetric information exists between market actors: aggregators do not have visibility into transformer load, and DSOs cannot predict when or where battery capacity will be activated by an aggregator. It should be noted that this lack of information sharing can be contributed, in part, to European/Dutch privacy law. However, this misalignment produces ineffective results, or in this case measures such as general trading restrictions that weaken the aggregator business case, even in places where there is no risk of congestion.

Market failure theory provides the justification for why a purely laissez-faire (leave things as they are) approach may not yield the desired congestion management outcomes (Zerbe Jr & McCurdy, 1999). The need for corrective measures are highlighted: regulated tariffs that reflect peak usage, anti-trust oversight by the ACM to prevent the wielding of local market-power, and subsidies for novel technologies that the market alone under-incentivises investments. In the Dutch context, it could be argued that the absence of a local congestion market itself is a failure. This leaves flexibility owners without an incentive to offer this to the DSO, via the aggregator, leading to inefficient outcomes (grid congestion).

2.3.3 Regulatory overshoot

The integration of DER into electricity markets is widely supported in policy design and academic literature. At the same time regulatory mechanisms which govern their deployment often lag behind in the level of necessary flexibility, i.e. deployment of new techniques outruns the adaptation of policy. We see that these are still catered to the past configuration of the market, which was centralised and without big price differences. Now, regulators and DSOs want to quickly establish restrictions. Several studies point out that poorly calibrated or overly rigid regulation, despite good intentions, can lead to significant market inefficiencies. Lade & Rudik (2017) show that overly rigid regulations lead to economic inefficiencies. In their study, the compliance measures did not reflect operational realities, which resulted in increased costs without achieving proportional benefits. The current situation is risking the same outcome, not necessarily in cost of implementation but in terms of missed revenues, or opportunity cost. Something similar is shown in Billette de Villemeur & Pineau (2012): market integration (congestion and imbalance markets in this case) without deregulation or adaptation of old rules creates inefficiencies. If regulations 'overshoot' their intended protective function, they can create economic barriers which reduce system efficiency and hamper innovation. The concept of regulatory overshooting is particularly relevant in the case of the proposed trading restrictions by the Dutch DSOs. The fixed-hour limitations, aimed at protecting transformer station, risk undermining the financial viability of residential battery aggregation by significantly reducing the available trading window. While the system operators are quite conclusive in the fact that over-regulating the market is not preferable (int 2; int 3; int 4), the current plans do exactly that.

Additional research reinforces this point across different domains. Kellogg (2010) argues that miscalibrated regulatory measures can inadvertently suppress valuable activities without significantly improving the target outcomes. Roques et al. (2005) emphasize that adaptive policy in the energy sector is important. As electricity markets evolve, regulatory frameworks should also adapt to avoid relying on outdated or rigid mechanisms that could distort investment incentives. They highlight the need for regulators to be forward-looking and design targeted interventions that address emerging risks without resorting to heavy-handed or overly simplistic controls. Even outside the energy sector, the phenomenon of overshooting is recognised. Caballero & Simsek (2020), in their analysis of monetary policy responses, discuss how aggressive interventions can lead to a disconnect between policy actions and actual needs. By analogy, this teaches that over-correction in policy (whether monetary or energy regulation) can produce a temporary illusion of security while creating inefficiencies elsewhere. Translating this back to DSOs and battery aggregators: a blunt restriction may guarantee transformers aren't overloaded, but it simultaneously freezes out flexibility that could have been deployed to everyone's benefit.
This disconnect between policy intent and projected economic impact, exhibit a form of misalignment. A more data-driven regulatory framework for the restrictions is needed to prevent this regulatory overshoot.

3 Methodology

This chapter outlines the methodological approaches that are used to answer the main research question and the sub-questions introduced in Chapter 1. The research is structured around a phased process that begins with a clear problem analysis/statement and this is followed by a system analysis that allows for the design of objectives and constraints the solution should fulfil. From system analysis follow what system variables can be adjusted to design the solution. The different phases of the research, and their specific employed approach are outlined in the following sub-chapters of this section.

3.1 Research approach

The research approach is designed to align closely with the sub-questions formulated in Chapter 1 and support a structured exploration of both technical and regulatory dimensions of dynamic congestion management. To guide this process, a hybrid methodology is adopted, combining elements from Design Science Research (DSR) as described by Peffers et al. (2007), and the solution-structuring approach proposed by Herder and Stikkelman (2004).

The study draws on the first two phases of the DSR process: problem identification and definition of solution objectives. These phases ensure that the research is problem-driven and grounded in the needs of stakeholders such as aggregators, DSOs, the TSO, and regulatory bodies. The Herder and Stikkelman (2004) framework further contributes by introducing the concept of the design space: a structured representation of what a solution can consist of, given the technical constraints, institutional rules, and stakeholder perspectives at play. This framework helps ensure that solution development occurs within a realistic, feasible, and stakeholder-informed scope, revealing trade-offs and tensions that must be resolved during the design process.

Rather than following the complete DSR cycle through to artifact implementation and evaluation, the research transitions after the problem-definition stage into a tailored, context-sensitive trajectory. This involves institutional analysis, is strengthened by stakeholder-informed qualitative interviews, and ultimately a literature- and policy-based evaluation of potential design directions. This hybrid strategy is well-suited to addressing real-world challenges in complex infrastructure systems where empirical piloting may not be feasible, or possible and where institutional factors are as important as technical ones. It is well-suited because complex infrastructure challenges are often “socio-technical” in nature, meaning that institutional, regulatory, and behavioural factors can be as critical to success as technical feasibility. Hybrid strategies that integrate stakeholder perspectives with literature and policy analysis allow for solutions that are both technically sound and institutionally implementable, even when piloting is constrained by cost, risk, or feasibility (Hevner et al. 2004).

The research addresses the growing tension between aggregator flexibility and grid security, specifically, the risk that static imbalance trading restrictions may overshoot their purpose and undermine the value of residential batteries for local congestion mitigation. The objective is to explore whether a more dynamic congestion management framework can satisfy the operational needs of DSOs while maintaining aggregator incentives.

3.2 Research phases

The research consists of five sequential phases, each aligned with a sub-research question. The progression of these phases ensures a comprehensive understanding of the problem context, the solution requirements, and the institutional limitations that define the viable design space. The phases, their objective and the chapter in which they're answered are presented in Table 1 below.

Table 1: Presentation of research phases.

Phase	Objective	Research approach	Chapter	Sub-question
1	Map market interactions and identify friction points	Review of Dutch electricity system, market design analysis and stakeholder interviews	4	How do the day-ahead, imbalance- and congestion markets interact and influence each other?
2	Identify institutional limitations and role conflicts for aggregators	Institutional and regulatory analysis, stakeholder interviews	4	How do current actor roles, responsibilities, and regulatory constraints influence aggregator participation in congestion management?
3	Define design boundaries based on system needs and stakeholder goals	Constraint mapping, stakeholder analysis	5	What system-level constraints and stakeholder objectives define the design space for a dynamic congestion management approach?
4	Identify feasible solution types within the design space	Information synthesis of previous chapters 4 & 5	6	What solution options can be developed within the design space based on the systems constraints and stakeholder objectives?
5	Evaluate and compare solution options	Qualitative assessment using predefined criteria	7	Which solution directions best fit the defined design space, based on regulatory, operational, and stakeholder-alignment criteria?

3.2.1 Phase 1: System structure mapping & interaction analysis

The first phase has the objective to gain understanding of the complexity in interactions between the day-ahead, imbalance, and congestion markets. It investigates how these market layers influence one another and what implications this has for other markets or parties operating across them.

This is achieved through a targeted review of the Dutch electricity market structures and roles (BRP, BSP, CSP) in the system. To validate and strengthen the analysis, semi-structured interviews are conducted with relevant stakeholders. The interviews provide insights into real-world operational practices. Furthermore, they give insights into the present challenges related to the navigation of overlapping market roles, such as an aggregator acting on imbalance and congestion. This phase aims to build a conceptual understanding of how actions in one market propagate into others and what systemic frictions might arise, ultimately answering sub-question 1.

3.2.2 Phase 2: Identifying data forecasting needs

Phase two explores how actor roles, responsibilities, and regulatory boundaries affect aggregator participation in congestion management. It investigates the institutional structure and constraints placed on different market participants, such as DSOs, BRPs, and aggregators. The research includes a review of legal documents (e.g. the Clean Energy Package), national regulation, and institutional protocols, complemented by insights from semi-structured stakeholder interviews. This phase helps identify where regulatory friction or role conflicts inhibit aggregator flexibility and answers sub-question 2.

3.2.3 Phase 3: Identifying stakeholder objectives and system constraints

The third phase consolidates technical limitations, institutional barriers, and stakeholder objectives to define the feasible design space for a dynamic congestion management solution. Through literature and stakeholder-informed analysis, it identifies what objectives each actor holds and what constraints must be respected (e.g. grid visibility, neutrality principles, market access). These inputs are translated into boundary conditions and prioritised goals, which together define the outer limits of viable solution directions. This phase answers sub-question 3.

3.2.4 Phase 4: Generating and structuring solution options

Phase four explores what variables can be adjusted in designing a solution. The defined design space and its identified variables are then translated into possible solution types. Based on findings from the previous phase, it draws from academic literature and industry initiatives to formulate a range of approaches, such as location-based price signals, local flexibility markets, and contractual congestion steering. These options are assessed for conceptual feasibility, institutional alignment, and regulatory consistency. The result is a structured set of solution directions, forming the response to sub-question 4.

3.2.5 Phase 5: Qualitative evaluation of solution options

In the final phase, the identified solution types are evaluated using a qualitative review based on the requirements and constraints gathered in earlier phases. The assessment focuses on three key dimensions: regulatory and institutional fit, stakeholder alignment, and operational feasibility. This comparative analysis relies on academic studies, regulatory documents, and stakeholder feedback. The aim is not to recommend a singular solution, but to determine which options best align with aggregator interests and system needs, thereby answering sub-question 5.

3.3 Data collection

Section 3.3 of this thesis presents the used methods for data collection. Three different methods for collection are used, a review of scientific literature, a review of grey literature & policy documents and semi-structured interviews. These are elaborated on in the sections below.

3.3.1 Literature review

Scientific literature has been selected to gain a thorough understanding of the current situation. The scientific literature used originates from the Scopus database. To ensure the relevancy of the articles, only articles from 2020 onwards were considered. In Table 6 the reader finds the search queries used to find articles for this part of the review. Search was done within the ''article title, abstract and keywords'' option of Scopus. Conference proceedings or journal articles were the documents considered. All articles which appeared in the search process were in the English language and could thus be analysed. In addition to the literature review in this proposal, literature which was previously used in course SEN232, 'Master Thesis preparation'', was added. Appendix A: Structured literature review also presents the selected articles from the literature review and their main take aways. The articles are discussed in more detail in the sections below the tables.

3.3.2 Expert interviews with market stakeholders

Interviews with several market stakeholders were conducted to gather insights from different perspectives in the market. These interviews were focussed on understanding the requirements which the intended solution needs to fulfil while at the same time mapping the current barriers to the implementation. The literature review laid the foundation for the questions for the semi structured interviews. The semi-structured approached is preferred in this case. It allows the interviewer to create broad outlines of what the interaction aims to achieve without having a set order or way of phrasing for the questions (DeJonckheere & Vaughn, 2019). This ensures that the interviewees will not be directed towards one solution/idea, and it provides better opportunity to explore particular themes or responses, should they be interesting (Adeoye-Olatunde, 2021). For the interviews, key stakeholders have been targeted.

Table 2 presents an overview of the interviewed market stakeholders. Their relevance to the subject is presented in an anonymous way along with some basic information about the interview. A summarised transcript of each interview can be found in Appendix C.

Table 2: Conducted interviews with market stakeholders.

#	Stakeholder organisation	Job description / activities	Reference code	Conducted on	Duration	Location

1	CE Delft	Researcher within sector energy & fuels with focus on electricity, congestion and flexibility	Int. 1	13th of March '25	52 minutes	MS Teams
2	Liander	Sector lead energy storage	Int. 2	14th of March '25	58 minutes	MS Teams
3	Tennet	Trainee Energy market & aggregation	Int. 3	24th of March '25	35 minutes	MS Teams
4	Stedin	Interviewee 1: System Strategist Interviewee 2: Product & proposition manager built environment	Int. 4	31st of March '25	54 minutes	MS Teams

3.3.3 Data management plan

The TU Delft, the leading institute in this thesis, demands that a researcher linked to their university follows strict data guidelines. The General Data Protection Regulation (GDPR) should be honoured at all times and the Human Research Ethics Committee (HREC) needs to approve the use of personal data during the research and in the output of the thesis. To align with these demands, a data management plan has been developed to ensure compliance with TU Delft regulations for data handling. In Appendix A the reader will find Table 8 containing the different data types, data sources etc. that will be used in this thesis. All collected data in this research will be stored in the TU Delft or Frank Energie OneDrive, depending on their sensitivity to the company's operations. Alongside this an informed consent form for interviews with market stakeholders, and a risk assessment analysis with risk mitigation strategies have been drawn up. The informed consent form is presented to interviewees before conducting the interview and informs them of the objectives of the research and the usage of their inputs. It gives them the opportunity to approve usage of their name or declare the wish to remain anonymous in the research outputs. After the interviews, a transcript summary will be presented to the interviewee, in which he/she can propose modifications. After the proposed changes are processed by the researcher, if there are any, the input is now ready to be published in the research output.
The data management plan and handling of personal data have been approved by the HREC of the TPM faculty of TU Delft on 03-03-2025.

3.4 Limitations to the research approach

The research uses qualitative methods to investigate possibilities to deploy aggregated batteries in congestion management while keeping imbalance trading from being constantly restricted. While the approach is designed in a balanced way, using knowledge from different sources, several limitations, and how these are addressed, should be noted.

First, the research follows elements of DSR, which it later on diverges from in favour of a more empirical path. This approach provides flexibility, but also means that traditional elements of DSR, such as iterative testing and continuous feedback loops are not fully implemented.

Instead, the emphasis is placed on the design and requirements for a well-designed framework that allows for residential batteries to be integrated in congestion management.

A second limitation that should be noted, is that the use of semi-structured interviews introduces potential for stakeholder bias. Given that the interviewed stakeholders in this research all have some connection to a DSO or a TSO (while being a separate entity, CE Delft has conducted quite some research on the instruction/request of DSOs) a certain attitude was observed. This attitude contrasts stark with the attitude of Frank Energie and other aggregators, both sides have strategic interests. The other side of course is that this research was conducted at Frank Energie, ensuring that the interests of both sides are considered.

In summary, the research faces some limitations in data availability, simulation simplifications, and possible bias in interviews. These issues are managed by using multiple sources of information and being transparent about the assumptions that are made at each point of the research. The limitations help defining what the research can and cannot say, and should be kept in mind when the results are applied and conclusions are drawn.

4 Dutch electricity system

The following chapter explains the configuration of the Dutch electricity system. An overview of the Dutch electricity market is presented. The actors and roles in the system are discussed, followed by the interaction that make the market so complex. Then, the regulatory context of the system is discussed, along with its shortcomings. The chapter is finalised by an overview of the different interests and capabilities of participants.

4.1 Dutch market overview

The Dutch electricity grid consists of multiple levels, each playing a role in balancing supply and demand, ensuring grid stability, and facilitating the energy transition. The key actors in the system include the TSO, DSOs, electricity producers, industrial and residential consumers, and energy companies. The distinction is made between the physical and administrative domain.

4.1.1 Actors in physical domain

TenneT – TenneT is the TSO of the Netherlands and parts of Germany where it owns and operates the high voltage (HV) grid (>110kV) (TenneT, n.d.). Within their operational tasks falls upgrading the grid where necessary and, the monitoring and balancing of supply and demand within the grid. It also engages in congestion management practises on the high voltage grid. Together with other TSOs TenneT works on an integrated European electricity grid. TenneT distributes electricity to big consumers, e.g. a factory, and to the distribution grid.

Distribution system operator (DSO) – DSOs, the biggest of which are Liander, Stedin and Enexis, take over the electricity grid below 110kV. Their focus is on distributing the electricity from the high voltage grid to end consumers. Like the TSO, the DSOs are responsible for planning, maintaining and exploiting their grid (TenneT, n.d.). They also measure consumption and production by their connections and report this to their suppliers and the TSO. The DSOs charge a monthly fee to all small consumers through their energy suppliers. These fees cover most of the costs the DSO incurs, but are expected to rise strongly in the coming years, with Berenschot (2024) projecting a 82% increase by 2030.

Producers – Electricity producers provide electricity from a variety of sources. This can be large scale, e.g. a wind farm or gas power plant, or on small scale through solar panels on the roof of a house. Depending on the size of the production a party should be connected on varying levels of the grid. Larger producers have responsibilities in the administrative domain.

Consumers – Consumers are any party which consumes electricity from the grid. Large consumers, like a factory, are directly connected to the HV-grid. Smaller consumers like households or small businesses are connected to the LV-grid through the DSO. In this thesis, households are the main consumer, since Frank Energie does not supply businesses. Any small scale consumer, or household, has a connection with a maximum capacity of 3x80 A.

Prosumers – Prosumers are consumers who also produce electricity and feed this back into the grid. The largest group of prosumers are households with solar panels, but factory, school, office or other type of building which produce electricity fall into this category. They are currently able to write off their overproduction in summer times against the increased consumption from the grid in the winter through the ''salderingsregeling''. This salderingsregeling will disappear in 2027 (Rijksoverheid, 2024), shifting the focus of prosumers to saving their own production and using it at a later time rather than feeding back to the grid. This strengthens the business case of a residential battery.

4.1.2 Roles in administrative domain

Balance responsible party (BRP) – BRPs have the responsibility to balance the supply and demand of electricity during the day. They do so to match the expected consumption and production of their connections as closely as possible to the actual consumption and production (PVNED, 2022). Per definition, energy suppliers, such as Frank Energie, are a BRP and thus have the responsibility for balancing the grid, and bear the cost for imbalance. When the portfolio of an energy supplier is not in balance, they need to buy (or sell) their additional electricity against the established imbalance price. This is depicted in Figure 3 below. Party A has excess generation, while party B has excess consumption. A then sells their excess to party B in the intra-day market. The remaining imbalance is solved by the TSO through one of the contracted BSPs. Signals for BRPs are on the national level. BRPs are financially charged for any remaining imbalances if they are not corrected before the end of an Imbalance Settlement Period (ISP), which lasts 15 minutes (TenneT, 2022c). Companies which aggregate flexibility can offer this to a BRP or use this if they're a BRP themselves.

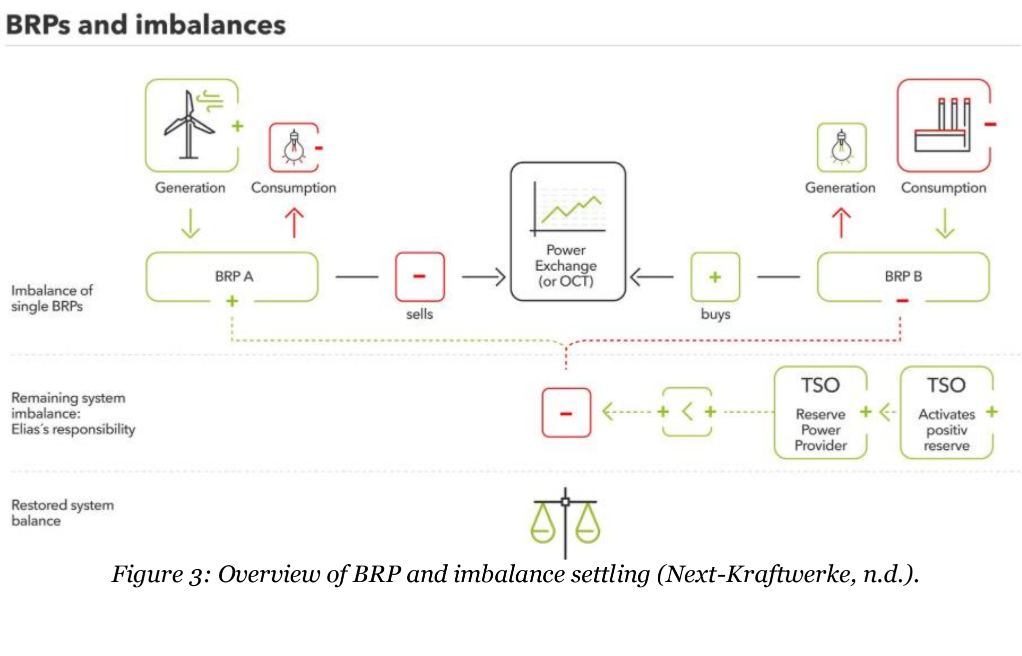

Figure 3: Overview of BRP and imbalance settling (Next-Kraftwerke, n.d.).

Balancing service provider (BSP) – BSPs offer balancing capacity and power to TenneT to cancel any unforeseen imbalances (Groendus, 2024). This is done in three ways: FCR, aFFR and mFFR, which all have their own specifications and rules. They range from fully automatic to manual control of frequency restoration. There is a strict set of qualifications which a BSP should fulfil before they can offer their flexibility to TenneT, one of those is the ability to offer both supply and demand flexibility. BSPs also need to be able to respond to imbalance signals from TenneT in seconds and scale up or down their capacity by 20% each minute. mFFR, manual frequency restoration reserve is a last resort in the balancing services, for instance when a power plant fails, and should be able to run at full capacity within 15 minutes (Next-Kraftwerke, n.d.). Aggregators can offer their flexibility to a BSP or use the flexibility directly as a BSP.

Congestion service provider (CSP) – CSP is a relatively new market role, which was introduced in the 'Netcode Elektriciteit' in 2022 (Liander, n.d.). A CSP offers congestion management services to the TSO or the local DSO. CSPs can make re-dispatch bids on behalf of the customers in their portfolio (Tennet, n.d.), for these re-dispatch bids a CSP is connected to GOPACS. The DSOs, who are connected to the GOPACS platform, inform CSPs when they expect congestion to occur at a location and offers a price for preventing this. CSPs then prevent congestion by having their customers to either lower consumption or production of electricity at the congested time. Since this role is relatively new, as previously described aggregators cannot yet act as a CSP. This is because one connection should at least have a capacity of 100 kW, which a single batteries does not have. At this moment discussions, between TenneT, the DSOs and market parties are underway to organise ways in which aggregators with smaller capacities can enter as a CSP.

4.2 Different markets and their interactions

The Dutch electricity market operates on different levels, the day-ahead market, the imbalance (real-time) market, and the emerging congestion management market. Together they ensure electricity is traded efficiently and that the grid remains stable and secure. The markets are deeply interrelated: decisions made on the day-ahead market have implications for real-time balancing and physical grid constraints. The following section analyses how these markets interact and influence each other, addressing both structural and operational coordination.

4.2.1 Day-ahead Market

The day-ahead market is (aside from the long-term market) the primary venue for energy trading in the Netherlands. It functions via the EPEX Spot exchange as part of the coupled European electricity system. Each day, BRPs submit bids and offers for a certain quantity of electricity for every hour of the next day (TenneT, n.d. B). The market clearing creates a dispatch schedule and a single zonal price for the Dutch bidding zone. The Netherlands is a single price zone in day-ahead trading. This means that transmission constraints are not causing different prices in different locations. Of course, transmission constraints are relevant for the overall delivery of electricity (Tanrisever, Derinkuyu & Jongen, 2015). TenneT provides available transmission capacity to the market clearing algorithm. Should any congestion occur as a result of the dispatch then it is up to the DSOs to manage this (Kok et al, 2022). The outcome of the day-ahead market heavily influences other markets: it defines each BRP's scheduled position, and any deviation from the schedule requires balancing actions or incurs imbalance charges (van der Linden, Romero & de Weert, 2021).
Traditionally, the day-ahead market is where aggregators (and other participants) allocate most of the volumes for their customers. This is based on forecasts of demand, production and price.

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4.2.2 Imbalance Market

After the day-ahead part of the system, it enters real-time operation. Here, actual supply and demand differs, without fail, from the forecast. The imbalance market, operated by TenneT, continuously balances these deviations. The frequency of the system needs to remain at (or very close to) 50 Hz, otherwise electrical components stop functioning and outages can occur (Tanrisever, Derinkuyu & Jongen, 2015). It does so by activating ancillary services like aFRR and mFRR from pre-contacted providers (BSPs) or through intra-day offers to correct any supply-demand mismatch. All BRPs in the system are financially responsible for their imbalances and must pay the cost of the marginal balancing actions taken by TenneT to cover the imbalance in their portfolio. To prevent gaming in the imbalance market (a party can first increase the imbalance, leading to a higher imbalance price, to then solve the created imbalance for a net gain) the system utilises a dual pricing mechanism (Stawska et al. 2021).

The functioning of the imbalance market has a critical influence on day-ahead behaviour: rational players will bid in day-ahead with the expectation of imbalance risk or opportunities. If the expectation is that imbalance prices will be very unfavourable, a BRP will try harder to be correct in their day-ahead bids (or correct in intra-day). However, if an aggregator expects the imbalance price to be higher than the day-ahead price, it may opt to withhold some flexibility to deploy later.

4.2.3 Congestion Market

Congestion management spans both structural day-ahead interventions and real-time operational actions. Unlike the centralised and transparent day-ahead and imbalance market, congestion management until recently happened more in the background. Now, a DSO must openly identify a congested zone & timeframe and conduct a detailed analysis to explore a solution. This analysis must be published within six months of identification, as mandated by the ACM. The mandate also states that market-based solutions must be sought before a DSO can deny new connections (Koninklijke VEMW, 2023). Additionally, the threshold for a flexibility offer has been lowered from 60 MW to 1 MW, allowing more producers/consumers to participate in congestion management. Aggregators, for now, are still excluded from congestion management.

In congested areas, BRPs, must declare how much of their contracted capacity could be curtailed if needed and at what price they would accept to do so (Pató, 2024). The DSO will then opt for the cheapest bid at congested times. This is done in real-time via the GOPACS platform. When a congestion event is expected, the GOPACS platform automatically matches a bid (in direction A) in the congested area with a counter bid (in direction B) in another area. That way the local load is relieved without changing the overall energy balance (Kok et al, 2022).

4.2.4 Interactions

In the sections above, the three markets are introduced and their interconnection is hinted at. Actions or restrictions in one market have consequences in other markets and understanding these feedback loops is crucial to answering the main research question.

- **From day-ahead to real-time:**

This is the most obvious interaction in the Dutch system, as day-ahead schedules set the stage for real-time balancing. Shortfall in generation or a spike in demand that was not planned for in the day-ahead market manifests as an imbalance that the TSO must address. Thus, forecast errors or deliberate deviations directly cause imbalance, increasing prices. Aggregators and BRPs continuously improve their forecasting and may trade in the intra day market up to five minutes before delivery to correct any deviations (Tennet, n.d. B). However, some imbalance remains inevitable.

The design of imbalance pricing strongly influences day-ahead behaviour: with highly unpredictable or punitive imbalance prices market participants become more cautious. This risk-averseness leads to them adjusting their day-ahead bids to lower imbalance exposure. At the same time, if a systematic profit is observed by an aggregator with certain behaviour, a not so risk-averse aggregator might forecast too little consumption and benefit of the imbalance prices. This is why the in section 4.2.2. mentioned “anti-gaming” controls were added.

Interaction between the two markets remains however, even with controls. In periods with expected renewable oversupply (e.g. summer months during school vacation), day-ahead prices drop and parties may choose to buy more electricity, anticipating that they can consume or fill up storage cheaply. Yet, if too many parties opt to do so, the system might shift into a deficit (e.g. due to a weather shift), which leads to unexpected and higher imbalance prices.

This interaction between the markets demonstrates why risk management is a core part of the activities of BRPs.

- **Impact of congestion management on day-ahead and imbalance markets:**

Congestion management, through the imposition of physical grid constraints, possesses the capacity to override market outcomes in both the day-ahead and imbalance markets. For instance, the day-ahead market may clear under the assumption that a particular region will inject 100 MW during a given hour (e.g., 12:00 PM). Yet, if the DSO identifies that the actual physical capacity of the grid connection is limited to 80 MW, it must intervene to curtail the surplus 20 MW. This intervention, often executed via the GOPACS, ensures that grid stability is maintained by mitigating overload conditions.

This leads to 20 MWh of electricity, sold day-ahead, that will not be delivered in real-time. This difference leads to an imbalance. The curtailed generator is now unable to deliver the contracted energy (i.e. they are short of the electricity that they sold) and must, through their BRP, buy back 20 MWh against the imbalance price. Simultaneously, another BRP is long 20 MWh on their forecasted position (or multiple BRPs are long a combined 20 MWh): they will have to dispose this 20 MWh at a potential financial loss.

Ideally, such discrepancies are identified and mitigated prior to real-time operation through adjustments in intraday trading. This is made possible when DSOs issue capacity limit notices ahead of time, typically the day before delivery. By providing early notification, DSOs enable market parties to adjust their positions in the intraday market, thereby preventing imbalance costs and preserving market efficiency (Pató, 2024). DSOs are obligated to inform BRPs of any planned activation of congestion management to prevent unnecessary economic consequences.

Still, imperfect coordination or unexpected congestion events may still occur and lead to imbalance swings. This is particularly common due to the limited visibility DSOs have into the real-time conditions of their distribution networks (Int 2). When aggregators experience curtailment of their flexible loads or distributed generators as a result of congestion management, their forfeit the opportunity to execute profitable trades. In addition, they may incur imbalance fees for deviating from their forecasted position. A technically advanced, agile aggregator might respond to a congestion management activation by redirecting the (de)activated load to another location and time if possible. However, regardless of such mitigation efforts, congestion management tends to reduce the effective capacity of the electricity market. Market transactions that were previously accepted during the clearing process may be altered or annulled, thereby diminishing overall market efficiency.

- **The balancing market versus congestion needs:**

When real-time balancing actions meet distribution grid constraints a particular challenging interaction occurs. This happens in two directions.
First, TenneT's balancing algorithm might activate a resource that worsens local congestion in a specific transformer. For example, when TenneT requires additional electrical power and subsequently calls on a network of EVs to halt their charging, thus providing upward balancing by reducing demand. Nevertheless, if these EVs are situated in a region that already experiences low load congestion (i.e. excessive generation without sufficient demand to utilise it, which may sound counterintuitive but can occur with solar), then reducing the load further can worsen the local overload situation. A DSO intervention is then required to prevent the region from the created overload, at cross-purpose with TenneT.
Second, an aggregator's flexible asset may want to respond to a high imbalance price, while by doing so overloading a local transformer. This is the situation DSOs are particularly anxious of. Active congestion management by the DSO would then prevent the flexible asset from responding at full capacity. From the perspective of the aggregator, the DSO is hereby actively denying it the chance to capitalise on a balancing opportunity and thus a revenue loss.
Stawska et al. (2021) show that using flexibility congestion management indeed diminishes the revenue aggregators get from the imbalance market. Simple congestion management schemes, e.g. static capacity limitations, are effective to avoid overloads, but significantly reduce what could have been earned in the imbalance market. Essentially, this is the cost for safety, some economic value is sacrificed for grid security. The only problem here is that this cost is borne by the aggregators instead of by the responsible DSO. More dynamic based schemes were found to be more preserving of imbalance value.

- **Feedback into day-ahead from congestion & imbalance:**

Over time, interactions in the congestion and imbalance markets can influence how BRPs (or aggregators through them) behave in the day-ahead market. Learning that certain regions are constantly congested at peak times may affect bidding strategies for aggregators. They can choose to not sell as much DR during the congested peaks because it is expected that the DSO will pay them to reduce their load or that they might be curtailed to keep the grid from overloading. Expectations of congestion can in effect cause a liquidity shift from the day-ahead market to the congestion market. In the same way, if imbalance prices have been very volatile because of renewable energy (and following a pattern), an aggregator can opt to either secure itself by covering more of their capacity in day-ahead, or it can keep some assets uncommitted to gamble for the option of selling in the balancing markets against higher prices.
Regulators, like the ACM, prefer that the most volumes get settled in the day-ahead or intraday market instead of the more costly, last resort options of the imbalance or congestion market. This is why the ACM has introduced a new broad package of measures that encourages large consumers to cut usage during peak times on their own, with price incentives (low network cost). This is preferred over an intervention by the DSO and should lead to less congestion activation and fewer imbalance price peaks (ACM, 2024-B).

- **Implications for aggregators:**

For aggregators like Frank Energie, operating at the confluence of these markets, the interactions provide both risk and opportunities. On one hand, the multiple markets provide aggregators with multiple revenue streams: electricity sales, imbalance optimisation, and DSO flexibility services or capacity payments (once aggregators can act as CSP). Data-driven aggregators can use forecasts to benefit from price arbitration by for example charging flex assets for cheap en discharging them during higher prices. On the other hand, the risk in misjudging the interactions can either cause revenue losses, or even inflict significant costs (e.g. by having to cover a position in the imbalance market without having flexibility available). This can get exacerbated when aggregators are allowed to act as CSP and plan to respond to imbalance prices but a congestion constraint prevents this.
Leveraging grid data to anticipate the actions of a DSO will play an important role in the interactions of the future electricity generation, assuming that data sharing will improve. Plans to increase data sharing are being developed in the "Stimuleringsprogramma Energiehubs 2024" (RVO, 2024). If a DSO publishes a congestion forecast for tomorrow at hour X in a certain zone, the aggregator can reduce its customers' consumption in that period beforehand. This avoids the aggregator being caught of guard by having to curtail and allows them to bid the reduction into the congestion mechanism for a renumeration.

4.2.5 Concluding the complexity of interactions

To conclude, the interplay of the day-ahead, imbalance and congestion management markets in the Netherland is characterised by a need for solid coordination between parties in combination with smart incentives. The day-ahead market drives the bulk of the economic activity, the imbalance market maintains the moment-to-moment stability, and congestion management ensures that the system stays within its physical boundaries. TenneT, the DSOs, BRPs, and aggregators must work in symphony, guided by the regulations set by the ACM to ensure that the three market layers reinforce instead of undermine each other. The Table 3 below summarises the most important interactions in the systems and the role of actors in at each market level.

Table 3: Overview of the interactions between the market layers.

Aspect	Day-ahead market (DA)	Imbalance market	Congestion market
Timing	Day-ahead auction for hourly contracts. Closes at 12pm D-1.	Real-time continuous market. Reserves activated seconds to minutes before delivery according to needs.	Both proactive and real-time. Day-ahead congestion forecast set limits before DA-market closure. Intraday or last-minute flex activations prevent overloads.
Participants	Generators, suppliers, traders, and aggregators (all via their BRP).	BSPs bid in reserve markets. All BRPs automatically in imbalance settlements.	Flexibility providers offer their flex to DSOs who pay for congestion relief.

Interactions with other markets	➔ Imbalance The DA-market is the baseline of imbalances; errors or strategic deviations lead to imbalance. ➔ Congestion DA-clearing ignores internal grid constraints so congestion management must correct impossible dispatch.	➔ Day-ahead Imbalance price trends feed back into DA-bids, parties either hedge or aim for arbitrage. ➔ Congestion Balancing actions can conflict with local grid limits. Coordination needed so balancing actions are checked with DSO's constraints.	➔ Day-ahead When DSOs impose capacity limits by D-1, it alters what a party can bid in the market. Also may undo some DA-trades ➔ Imbalance Curtailments create deviations with BRPs, leading to imbalance. This needs a countertrade. Well-organised this is settled in GOPACS. Poorly coordinated and it leads to unexpected balancing needs.

4.3 Aggregators in the system

Aggregators have emerged in the Netherlands as a new market entity that pool DERs, among them batteries, and offer this flexibility into energy markets (Juffermans, 2018). In the current Dutch market context, many aggregators operate as combined supplier-BRPs that manage a fleet of customer assets to optimise energy buying/selling. They strategically dispatch these aggregated resources across various market layers (Frank Energie, 2025). The aggregator's software platforms continuously monitor prices and grid signals, using algorithms to decide when to charge or discharge batteries, curtail loads, etc., with the goal of maximising economic returns while meeting any operational constraints.
Aggregators participate across various electricity market segments to monetise flexibility. Six services primarily offered by aggregators have been identified: (1) providing balancing reserves to the TSO for real-time grid balancing; (2) optimizing within a BRP's portfolio to reduce imbalance costs; (3) trading in wholesale markets (day-ahead or intraday) by scheduling flexible load/generation in response to price signals; (4) supplying contracted flexibility for congestion management to the TSO; (5) supplying flexibility to distribution system operators (DSOs) for local congestion management; and (6) even in emerging local capacity or adequacy mechanisms (Juffermans, 2018). In the Netherlands aggregators of residential batteries mainly focus on the provision of balancing services and portfolio optimisation to reduce imbalance costs. In part because other options are not legally allowed, yet.

4.3.1 Aggregator participation

One of the primary roles that aggregators in the Netherlands adopt is providing balancing and ancillary services to TenneT. Traditionally, only large power plants or industrial consumers could participate in balancing markets, but aggregators allow pooling of many smaller resources to meet minimum bid sizes and reliability criteria. Independent aggregators can register as BSPs and partake in frequency control and balancing reserve markets (FCR & aFFR), even when the assets are connected to another BRP (Sáez Armenteros, de Heer & Bjorndalen, 2022). In practice, TenneT implemented technical mechanisms to correct the BRP's energy imbalance caused by an independent aggregator's activation. This allows aggregators to help balance the grid without penalising the original energy suppliers of the customers providing flexibility.

Despite the recent interest, aggregator participation in Dutch markets is still evolving. Minimum size thresholds (and strict prequalification requirements historically limited access for small units, although ongoing European integration is reducing entry barriers. The Netherlands' implementation of the EU Electricity Balancing Guideline has been a catalyst for defining aggregator roles in balancing. By policy, an independent aggregator performing the BSP role is allowed to offer balancing services without being the customer's BRP or supplier, provided certain corrections and settlements are in place (Sáez Armenteros, de Heer & Bjorndalen, 2022). This allows more competition in the market as it enables third-party aggregators to compete with traditional generators.

4.3.2 Aggregators in congestion management and local flexibility

Aggregators also play an emerging role in managing network congestion and providing local flexibility in the Netherlands. With rapid growth in distributed solar PV and electrification (e.g. electric vehicles, heat pumps), certain areas of the Dutch grid face capacity constraints. To address this, Dutch grid operators (TenneT and DSOs) have developed market-based congestion management platforms that rely on flexibility from market participants. The flagship initiative is the GOPACS platform, a joint platform by TenneT and all Dutch DSOs. GOPACS allows aggregators and other market parties to offer location-specific flexibility to relieve grid congestion in exchange for compensation (GOPACS, n.d.). In practice, when a DSO or TSO anticipates an overload in a region, they publish a request on GOPACS; aggregators (of large/industrial connections) can bid to curtail load or increase local generation to alleviate the bottleneck. This market-based approach is unique in Europe it creates a win-win situation where grid operators solve congestion cost-effectively and aggregators earn new revenue streams by monetising their flexible assets. By 2021, multiple aggregators and suppliers had begun participating in these redispatch markets through GOPACS connected trading platforms, marking the integration of aggregators into DSO operations.

4.3.3 Incentives and drivers

The rise of aggregators in the Dutch electricity system is driven by a combination of financial incentives, customer value propositions, and regulatory motivations. First and foremost, the business case for aggregation revolves around financial drivers: aggregators earn revenue by selling flexibility services or energy adjustments into various markets. The potential profitability has grown as the system's need for flexibility increases with more renewable generation (Strategy&, 2021). Aggregators create value by arbitraging price differences (e.g. charging batteries when electricity is cheap and discharging when prices peak) or by earning availability payments (for keeping capacity ready to respond to grid needs). Aggregators on MV- and HV-grid levels, rely on capacity payments from TenneT's reserve markets or from interruptible contracts, since actual activation of industrial demand response may be infrequent (Sáez Armenteros, de Heer & Bjorndalen, 2022). At the same time, rising imbalance prices and volatility in energy markets, due to the increase of DERs, have increased the arbitrage opportunities for aggregators. Overall, the energy transition is enlarging the flexibility gap, which strengthens the incentive for aggregation as a profitable business model (Strategy&, 2021; Juffermans, 2018). For the end user providing flexibility, the primary motivation is typically monetary compensation or cost savings. Aggregators often share a portion of the revenue (or saved costs) with the customer or reduce the customer's energy bill when they curtail usage (Frank Energie, 2024).

4.4 Regulatory context for aggregators in the Dutch market

The electricity market is a highly regulated market because of the dependency of every day life on its functioning. This reliability needs to be guaranteed and thus the market and its participants follow strict rules. The following part presents the most important regulations for aggregator operations. Not all issues that hinder the deployment of residential batteries in congestion management are of technical nature. Hinderance also follows from EU and Dutch regulations, that simply don't allow for certain configurations that would be beneficial to residential battery aggregators. Additionally, interviews 3 & 4 have made clear that different market participants do not always agree on the coverage of certain regulations.

4.4.1 Commission Regulation (EU) 2017/1485 Article 182 sections 4 & 5

These sections, from the system operations guideline (Entso-E, 2021), discuss what type of restrictions DSOs can set during the prequalification phase for reserve providing groups or units in their distribution systems. Notably the article empowers DSOs to set technical limits or exclude units from delivering reserves based on factors like geographical location. This is done to protect the grid from overloads. Furthermore, before each activation, DSOs may set a temporary limit on reserve delivery from distribution connected resources.

However, this regulation discusses the delivery of active power reserve and passive imbalance is not (specifically) covered by this article. Passive imbalance is governed by the Electricity Balancing Guideline (EBGL), which states that imbalance settlement must be non-discriminatory across the whole bidding zone. So, anyone who can respond to an imbalance signal should be allowed to respond to this signal, even if their preferred location is a known congestion zone already.

According to interview 4, the sections in this article are open to interpretation and allow for a passive imbalance signal with a locational specification. However, interviewee 3 stated that these do not allow for the specification of location. Interviewee 3's employer, the TSO which provides the signal, is reluctant to intervene in the market and impose locational restrictions, as this contradicts the principles of the free market. They stated that the capability to specify the location where they would prefer the passive imbalance reaction to come from, yet they are unable to act on this. When regulations change however, this could be implemented fairly easily (Int 3).

4.4.2 Netcode electricity article 9.32 section 3, article 13.4 section 2.

The Netcode elektriciteit contains descriptions for operators and users of the electricity markets in three areas: the functioning of the grids, connecting new customers to the grid and the transportation of electricity in the grids. The Netcode has recently begun to formalise the role of independent aggregators, often termed as CSP and establishes criteria for CSP recognition.

Article 9.32.3 states that a CSP, which could be an aggregator, can provide the DSO with congestion management products on behalf of connections with a capacity of 1 MW, this can be both for consumption and production. This capacity requirement eliminates any residential battery (typically between 3 and 10 kW) from being used for congestion management in the form of redispatch. A 2022 code amendment did allow CSPs to aggregate multiple smaller units to meet the requirement (Besluit ACM/UIT/575492).

Nonetheless, the bid size in practice remains at 1 MW, meaning that an aggregator must pool hundreds of residential batteries to participate. Contradictory to this, the pre-qualification

form from TenneT with guidelines for connections and offering congestion management products states that a connection should have a capacity of at least 100 kW to qualify for the CSP (TenneT, n.d. – A). Besides this, the legal minimum size for a re-dispatch bid is 100 kW (Netcode Elektriciteit, n.d.). This number is still not achievable with one residential battery (or connection), but aggregated batteries (or connections) could reach this threshold.
Chapter two highlighted the flexibility potential of residential assets. Yet, this potential cannot be fully realised if market entry is conditioned on assembling large portfolios. When aggregators reach a contracted capacity of 100 kW at a single LV-transformer station redispatch bidding would be possible in the current setting. This insinuates at least 10+ (assuming capacity <10 kW) batteries per transformer (that should also be connected to the same CSP, or there should be communication between CSPs), while adoption is growing this is still a distant reality. The current market only conducts redispatch on the HV- & MV-grids. If multiple LV-transformers feeding into the same MV-transformer can achieve a cumulated capacity of >100 kW flexible capacity, redispatch bidding could be done at the higher grid levels by leveraging residential batteries. This would bring other difficulties, like communicating what LV-transformers are connected to one MV-transformer. Conversely, lowering the capacity requirements for congestion management services would allow residential batteries to participate for purely locational LV-transformers as well.
In summary, the national code's current market access rules, which have improved in the last 5 years, are still skewed toward large-scale resources. This reflects a lingering regulatory bias against small DER aggregations.

4.5 Shortcomings in current regulations for residential battery flexibility

Building on the analyses of the previous chapters, several regulatory shortcomings have been identified that currently impede aggregators from deploying residential batteries. These include (i) restrictive market access rules, (ii) unclear role definitions, and (iii) data accessibility and privacy constraints.

- **Restrictive market access**

As noted above, the minimums size thresholds and prequalification requirements effectively bar residential battery owners from direct participation. An aggregator focusing on residential batteries must aggregate a large number of assets to meet the 1 MW product size for congestion management or balancing services (Pató, 2024). The intent was likely to ensure meaningful impact and limit the administrative burden. In practice it represents an exclusion of smaller participants: residential flexibility that could cumulatively mitigate local grid stress is left untapped. Moreover, DSOs' broad authority under EU and national rules to deny or limit distributed reserve providers on "technical grounds" can be used in conservative ways. Concerned DSOs may pre-emptively exclude a whole group of battery aggregations from providing upward regulation, even if real issues would only arise in specific neighbourhoods.

- **Unclear role definitions**

A recurring theme is the is the ambiguity in the roles and responsibilities of aggregators relative to suppliers, BRPs and grid operators. The clean energy package (EU directive 2019/944), introduced the concept of independent aggregators and requires operations without consent of the supplier of the customer. The Netherlands has begun shifting these provisions (e.g.

through the registration of the CSP), but some critical role conflicts remain. One issue is how a BRP will be settled on imbalances that are caused by the aggregator's actions. If dynamic congestion management reduces loads, the BRP of these connections may end up with a surplus of electricity that was bought day-ahead. This incurs imbalance costs for the BRP.
EU guidance is undecided on compensation schemes but calls for standardised compensation mechanisms (Bray & Woodman, 2019). The Dutch implementation is also undecided. With DSOs apparently unwilling to provide a renumeration (Hulshof, personal communication, 2025), while the InterFlex pilot did propose payments for flex offers. As a result, aggregators face uncertainty about both their liability for the caused imbalances and the to be received compensation for their flex bids. This creates barriers and risk. It may also lead aggregators to prioritise imbalance arbitrage over congestion participation, purely for economical gain. To cancel this, rules about the 'chain of command' should be established.

- **Data sharing and privacy limitations**

Effective congestion management with residential batteries requires data-sharing. However, privacy regulations tied to the GDPR and data siloing (keeping it within one organisation) present a significant hurdle. The Netherlands has strong data protection practices, smart meter readings are by default not transmitted with a supplier due to privacy concerns, unless the owner of the meter opts in. When the data is available, DSOs and data registers must ensure compliance with GDRP. With the current rules, an aggregator lacks access to the required data due to GDPR. The same regulation prevents DSOs from forwarding this data to an aggregator without legal basis. There are ways to obtain approval for certain data destinations, but as noted by interview 4 this takes a long time to receive. This misalignment, where DSOs know where flexibility is needed and where aggregators know where flexibility is present but not where it is needed creates a paradox.
The combination of data access barriers and privacy safeguard as currently implemented, while it protects consumers, also limits the agility and precision with which aggregators can respond to congestion events.

- **Grid tariff structure**

The Dutch grid tariffs are structured in a way that significantly differs from those in many other European countries. Where (most) other countries use a volume based tariff, the Dutch system is based on the maximum capacity you can off take and is independent of the time-of-use (ToU). The division of different types of grid fees are depicted in Figure 4 below. The Dutch tariff is determined based on the capacity of the connection in a household. It won't change, unless the connection is physically up- or downgraded. This entails that within the range of your connection your usage does not influence the price you pay. As there is a standard connection, most households pay the same amount, while only a small percentage is responsible for causing congestion. Technologies such as an EV, residential battery or heat pump put more stress on the grid. The ACM has recently spoken out support for changing the grid fee structure, to better charge the heavier users of the grid (ACM, 2024). Batteries are now identified as possible technology causing congestion problems, when they react to imbalance signals. If this is the case, in the current set up, the causer of this congestion problem does not bear the cost, rather this is shared over the full network (Berenschot, 2024).

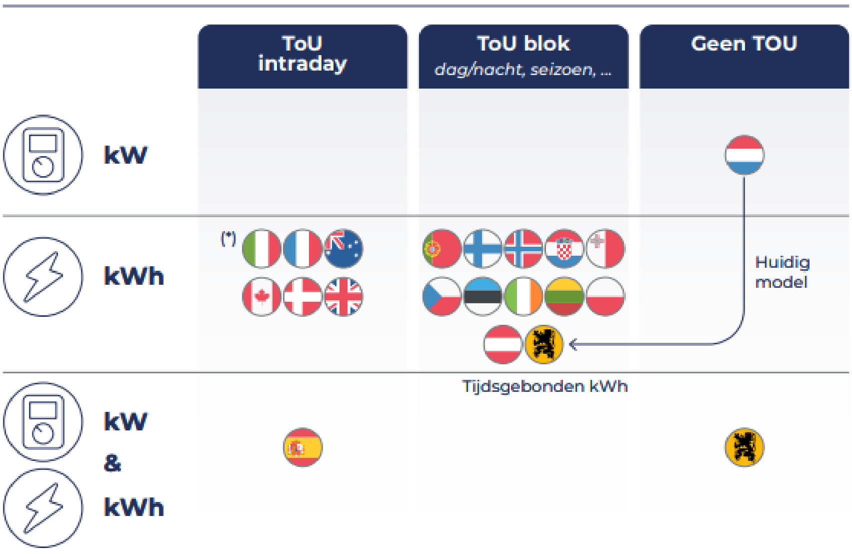

Figure 4: Grid tariffs in European countries (Fluvius, 2023).

The current non-existing incentive for battery owners, or aggregators, to act in a congestion mitigating manner is likely to drive congestion problems further as they chase financial gains. This is the main concern of DSOs and the reason why they intend to impose restrictions (int 2; int 3; int 4). While DSOs acknowledge that batteries have great potential in mitigating congestion, they are reluctant in offering a renumeration for the provided services by aggregators (Hulshof, personal communication, 2025). Furthermore, research by CE Delft (2024) has shown that ToU tariffs negatively influence the business case for a battery, when the focus in on imbalance trading. ToU tariffs are expected to benefit the battery business case when the focus is on optimising individual actors' power costs, as price differences within a day will increase (CE Delft, 2024). Since the overhaul of grid fees would take multiple years to realise, I believe that either a loss of revenue from missing out on imbalance trading or a discount on the grid fees should be offered to battery owners/operators. A distinction could be made here between not causing congestion and helping solve congestion, but that may raise several concerns with exact measurability. This thought about renumeration is shared by both CE Delft (2025) and Berenschot (2024).

4.6 View of market participants

Electricity market stakeholders each have distinct perspectives on the current system's challenges and perceived failures. Their objectives and concerns differ, which often leads to differing opinions on issues like imbalance trading restrictions and congestion management. Below I elaborate each point of view. This is based on the conducted interviews, internally available knowledge within Frank Energie and my experiences from working, since 2022 and studying since 2019 in this field.

4.6.1 DSO perspective

'Grid safety first' is the main takeaway that follows from the conducted with employees of DSOs. DSOs are responsible for local network reliability and see unmanaged flexible trading as a risk to the physical grid. Facing rising congestion on transformers and feeders, DSOs tend to take a conservative stance. This is why DSOs argue that strict measures (like temporarily limiting battery charging/discharging during peak periods) are perfectly sensible to prevent overloads (Int, 2; int 4).

From the DSO point of view, the current system's shortcomings are due to market signals not accounting for network constraints. DSOs are currently undecided on the influence of batteries of the market. With the current usage they view batteries as a negative influence on grid congestion because the imbalance price signals do not account for grid conditions. At the same time they note that batteries have the potential for congestion mitigation when they are used in the right way. This is why DSOs currently feel justified imposing restrictions on aggregators as a "fail-safe". In their view, the imbalance market was designed for system-wide balancing, not to consider distribution bottlenecks; if unrestricted, enthusiastic aggregators might chase profit at the expense of local stability. DSOs often highlight that the cost of failure (grid damage or outages) is too high, so pre-emptive curtailment of flex traders in congested areas or hours is, to them, a reasonable trade-off. This follows logically from their main operational task; keeping the grid available, reliable, and secure for all connections. They do acknowledge that this approach is not a long-term solution, but until better coordination exists they have to prioritise DSOs avoiding any network incidents. The safest way to do so, in their eyes, is taking away uncertainties, or uncertain loads. Similarly, they acknowledge that they need to improve their insights into the grid and improve transparency for other parties.

4.6.2 Aggregator perspective

'Unlock flexibility, don't stifle it.' Frank Energie as aggregator has nearly the opposite view of the DSOs. From their perspective, the current system fails/is at risk because overly strict DSO restrictions blunt the efficiency and value of demand-side flexibility (Frank Energie, personal communication May 2025). An aggregator such as Frank Energie contends that banning or capping battery trading during certain hours is a crude solution that causes them and their customers to lose revenue opportunities. Similarly, aggregators generally positive ideas about reforming the grid tariff structure to a ToU-tariff as it will increase the arbitrage gap (Hulshof, personal communication, April 2025). Furthermore, they point out that customers invested in batteries to save (or perhaps even make) money and support grid balance, and now they are being penalized for responding to price signals. Aggregators operate on the principle of neoclassical economic behaviour: if there is a price incentive to charge or discharge, it makes sense to do so.

While aggregators do not deny the risk of potentially overloading LV-transformers they argue that the problem is not their profit-seeking behaviour per se, but the lack of a more nuanced system to guide that behaviour at the local level. They publicly call for dynamic congestion management. If DSOs provided real-time local congestion signals or flexibility markets, aggregators could adjust their dispatch to help the grid rather than hurt it (Frank Energie, 2024). From this view, the failure of the current system is a market design failure: the absence of integration between wholesale/balance markets and distribution constraints. Innovation and progression in the market is hindered by risk-averse grid operators. Aggregators advocate for increased coordination between market parties, instead of curtailment.

4.6.3 TSO perspective

'Maintain balance & fairness.' TenneT sits at the national level, responsible for overall system balance and stability. From TenneT's perspective, balancing resources from aggregators are valuable for managing the grid frequency, and any barriers to their participation could reduce efficiency in the balancing market. The TSO generally supports broad, non-discriminatory access to the imbalance markets, as mandated by EU regulations, meaning any resource in the control zone should be free to respond to imbalance price signals. They are also big believers in free market principles, and they prefer to act as little as possible in a constraining manner (Int 3). This is why, in the current debate, TenneT tends to be cautious about introducing location-based restrictions or bespoke curtailments for some players in the imbalance market, as this undermines the "level playing field" principle. TenneT is at a conflict of interests. From their view, the system fails if local issues start to interfere with national balancing operations. However, TSOs also recognize that ignoring DSOs' problems is not sustainable: a conflict between balancing needs and distribution constraints could jeopardise system reliability.

4.6.4 Consumer perspective

'Cost saving and fairness.' From the end-user point of view, based on experiences from the Frank Energie customer support team, (especially those who invested in technologies like home batteries, EVs, or solar), the current system's promise was built lower bills and greener energy through active participation. Many prosumers with dynamic contracts behave rationally to minimise their costs and maximise returns, e.g. by using their batteries for trading in several markets. They generally welcome aggregators' services (following from the steady rise of new flexibility customers for Frank Energie) that help automate these savings. DSO or TSO restrictions, causing their assets to sit idle when they could be earning money or lowering bills, causes discontent (Frank Energie, 2025).

From their perspective, the failure of the system is that different parts of the energy sector are not aligned since they did "the right thing" by being flexible, yet now they face limitations without clear compensation. These are similar complaints as those that came as reaction to the discontinuation of netting (salderingsregeling). Two lawyers started a petition to start a mass claim against the government on the argument that ''for years people have been pushed towards solar panels, and if you now install them you get punished for feeding electricity back into the grid.' (SolarMagazine, 2025). On the other hand, consumers also value reliability. Some may accept that if the local grid is truly at risk, a temporary limitation is necessary, but they expect this to be a last resort, and they want transparency about why it's needed.

4.6.5 Regulator perspective

'Balance innovation with safeguards.' The ACM observe the multi-actor standoff and focus on the market design and the rules that underpin it. They see that the current system is strained: market rules did not fully anticipate active distribution-level trading, leading to gaps and conflicts. The ACM acknowledged that changes need to happen, for instance an adjustment to grid tariffs to divide grid costs more fairly (ACM, 2024). They also acknowledge that a better use of flexible assets alleviates congestion and enables more new connections to join the grid (ACM, 2024-B). The regulatory view is often that the principles of non-discrimination and open markets must be upheld (echoing the TSO's stance). Yet, at the same time, they acknowledge that DSOs require tools to manage congestion in a more dynamic future. The difficulty for the regulator lies in the adjustments that need to be made. The current grid tariff structure may not represent the costs caused by each user in the most optimal way. However, if they change the current structure to a ToU-tariff for instance they must be absolutely certain that it is an improvement and nobody is unfairly impacted.

5 Stakeholder objectives and system constraints

Using the Herder & Stikkelman (2004) conceptual design approach, this chapter articulates the goals, constraints, data needs, and requirements for dynamically managing distribution grid congestion via residential battery storage. In this framework, performance objectives are the stakeholder goals to be optimized, while constraints are the conditions that any design must satisfy (Iychettira, 2018). The objectives and constraints are of differing nature, highlighting the complexity of the problem. For both the objective and constraints I highlight where trade-offs occur.

5.1 Performance objectives

A dynamic congestion management approach with residential batteries must balance the objectives of multiple stakeholders in the system. Key stakeholders include DSOs, aggregators, con/prosumers, and regulators. Their objectives are interrelated and sometimes contradicting, requiring careful design trade-offs (e.g. between cost efficiency and security). The following requirements are identified for each of the stakeholders:

5.1.1 Distribution System operators

DSOs have the goal to maintain network reliability and safety by preventing thermal overloads in cables, feeders and transformers, voltage violations and outages in the distribution grid. At the same time they want to connect as many users as possible to the grid. A primary objective is to relieve local congestion efficiently so that power flows stay within the capacity of the equipment and voltage stays within the set boundaries (Int 2; Int 3; Int 4). DSOs also seek to defer costly grid reinforcements by leveraging flexibility; using residential batteries to shave peaks and fill valleys can postpone the need for cable and transformer upgrades (Bhattacharyya, van Cuijk & Fonteijn, 2019). This translates to economic efficiency objectives, often measured by avoided upgrade investments (€) or reduction in peak load (%) on critical network assets. Furthermore, a curtailment situation should not result in a peak right after the curtailment period, the so-called waterbed effect. A situation where curtailing the load and thus mitigating congestion in location a certain location at time X leads to congestion in that same location at time Y (ANW, n.d.). A third objective for the DSO is enabling the energy transition by accommodating more renewable generation, new loads and new/upgraded connections within the existing infrastructure. Indicators for DSOs include the number of mitigated congestion events, congestion duration (time) reduced and voltage quality maintained within EN50160 limits (The EN 5016 standard states the limits for voltage characteristics to be met by the power grid (Neo-Messtechnick, 2021)).
Lastly, DSOs must ensure that the operational costs for congestion management remain justifiable and within the financial boundaries set: congestion management spending per MWh is capped by the ACM (ACM, 2022).

5.1.2 Aggregators

Aggregators serve as intermediaries bundling many residential batteries into a controllable fleet. Their chief objective is profitability through flexibility services, i.e. earning revenue by trading or dispatching the aggregated battery flexibility in response to DSOs' congestion needs (and also TSO balancing needs). Aggregators aim to maximise the value of the batteries by 'value stacking' multiple services (imbalance market participation and providing congestion relief) (Fonteijn, 2021). To achieve this profitability, it would greatly benefit aggregators if they're allowed to act as CSP. So the to be designed solution also has the objective that it ensures market access for aggregators.

A sub-objective here is to ensure reliability of service delivery to the DSO. The aggregator must meet dispatch requests precisely and consistently. Failure to deliver promised flexibility could incur penalties, damage grid infrastructure or erode trust between parties. Thus, aggregators monitor performance indicators like activation success rate (% of requested flexibility actually delivered) and response time of their assets (Marquine, personal communication, June 2025).

Besides the revenue maximisation, a second economic objective for aggregators is lowering the electricity cost of their customers. By doing this better than competitors they draw new customers, that in turn allow them to leverage more flexibility in the markets.

For Frank Energie specifically, the additional objective "accelerating the energy transition" is stated, besides generating a profit for customer and company alike (personal communication Verbeek & Hulshof, 2025). This underscores the innovative direction of aggregators. By not leveraging the flexible assets in the portfolio, an aggregator not only misses economic opportunities but also withholds valuable capacity from the flexibility markets.

5.1.3 Consumers and residential battery owners

Consumers with batteries (often coupled with rooftop PV) have dual objectives: maximise their own energy benefits and participate in flexibility services for compensation. On the one hand, they install batteries to reduce electricity bills (through peak shaving and time-of-use arbitrage) and to increase PV self-consumption or have backup power. On the other hand, by enrolling with an aggregator, they seek additional financial incentives for allowing their battery to be used in imbalance and intraday markets.

A key objective for battery owners is that participation with their assets in congestion management should not compromise their energy needs or equipment. For example, a consumer will require that using the battery for grid services does not excessively degrade the battery's lifetime; thus, battery health and warranty compliance is an implicit objective. Secondly, battery owners must be compensated proportionally for their contribution. Compensation should reflect the value of avoided grid investments or congestion penalties, and cover opportunity costs of foregone market participation (Brouwer et al., 2022). In line with this is the valuation of fairness and transparency by battery owners. They want to be fairly rewarded for the flexibility they provide and to understand the terms on which their assets is used (Frank Energie, personal communication, July 2025). Important performance indicators from the prosumer perspective include monthly savings/earnings, impact on self-consumption, and battery throughput.

Another objective to keep in mind is one of 'regular' consumers, those who do not own a battery. For them residential battery operations make no difference as long as the operations do not worsen their current position (e.g. cause outages or increase grid cost for everyone). As this is by far the larger group of consumers, it is an objective that can't be forgotten.

5.1.4 Regulator

Regulators such as the ACM and energy policy makers have the objective to ensure that any congestion management scheme is fair, non-discriminatory and aligned with energy transition goals. They seek to protect consumers and ensure market fairness while enabling innovative solutions to grid problems. A top-level objective is system efficiency, leveraging distributed resources like residential batteries to solve grid issues at lower cost than traditional grid expansion, ultimately benefiting all grid tariff payers.

However, this must be balanced with fairness. Regulators want to prevent undesirable outcomes where only a select group of consumers benefit or there is abuse of market power by dominant players. In line with this fairness is the objective that the ''polluter pays" principle, only is the polluter in this case a heavy user, the causer of the congestion. The ACM has previously expressed their support for changing the grid fee structure, also acknowledging that this will take a lot of time (ACM, 2024). This is why regulators are cautious with adopting more dynamic tariffs as it may disproportionately affect a certain group of customers (Chondrogiannis et al., 2022). A second objective of the ACM is to ensure that competition and innovation are stimulated, while keeping products and services in the market at reasonable prices (ACM, n.d.). Thus, the solution may not put any party in the position where it becomes a monopoly. Similarly, the solution should ensure that any one party can participate in the solution (when they meet the prequalification) as is described in the Netcode Elektriciteit for imbalance market (Overheid.nl, 2025).

Regulators also impose consumer protection objectives: ensuring data privacy, cybersecurity, and that participation in flexibility programs is voluntary and informed. Another regulatory objective emerging in the Netherlands is facilitating new connections and reducing waiting lists by using flexible contracts. In effect, regulators want congestion management to speed up the connection of new solar, wind, or demand by making better use of existing grid capacity.

5.1.5 Trade-offs and tensions

Achieving all the above objectives simultaneously can be challenging, and trade-offs are inevitable. A notable tension is fairness vs. efficiency. For instance, a purely market based dispatch that selects only the cheapest batteries for congestion relief will minimise cost (efficiency), but regulators might worry if the benefits (payments) accrue only to certain participants, potentially leaving others (who lack resources like batteries) at a disadvantage. Ensuring fairness might mean designing interventions so that all capable consumers have an opportunity or setting criteria to prevent one aggregator from monopolising the market.

There is also a reliability vs. market freedom tension: DSOs might prefer direct control or contracted guaranteed curtailment for assured reliability, whereas market-based operation gives aggregators freedom to decide when to offer flexibility. Excessive control could reduce the aggregators' ability to maximise their profits, whereas too much freedom could jeopardise the DSO's confidence that congestion will indeed be resolved when needed.

Another key trade-off is consumer benefit vs. asset wear: using residential batteries more aggressively for grid support yields greater network benefits and potentially more remuneration, but it also increases battery cycling, possibly reducing battery lifespan. The design must strike a balance, for example by compensating degradation or by limiting service activation to critical periods only.

5.2 Constraints

The proposed solution must operate withing a set of constraints. These include technical limitations of the battery and the grid, market and economic constraints as well as consumer protection and social constraints. I categorise and detail these below, noting that they are critical design parameters: any acceptable solution must satisfy them while optimising the identified objectives. I have opted to not take the regulatory constraints into account here, as current legislation is excluding aggregators from acting as a CSP. Having the current legislation as a solution constraint would make it impossible to find a workable solution where aggregators actively help managing congestion.

5.2.1 Technical constraints

Batteries:

The physical capabilities of the batteries impose hard constraints on what is feasible. For one, each residential battery has a limited power and energy capacity. A battery can only discharge at most up to its inverter's rating. In the case of Frank Energy the range is between 2 and 25 kW (Frank Energie, n.d.) and only until its stored energy is depleted. This means the magnitude and duration of congestion relief a single battery can provide is bounded. E.g. a 5 kW/10 kWh home battery might sustain a 5 kW discharge for 2 hours at most. The design must aggregate enough batteries or curtail sufficient load to meet a given congestion need.
Likewise, battery charging/discharging cannot be instantaneous; there are response time constraints, however small, the control signals and coordination add latency (Verbeek, personal communication, June 2025). However small the influence,
Similar to car batteries, most residential batteries have the state of charge set to remain between 20 and 80% of the total capacity to prolong the battery life, further constraining the amount of power that can be dispatched.

Distribution network:

The distribution network's technical limits are equally important. Cables, transformers, and other equipment have thermal ratings (capacity in Amps or kW) that cannot be exceeded without risk of failure. Voltage levels on each feeder must remain within statutory bands. As followed from the interviews with DSOs, LV-transformer stations have a capacity of 400 kW. Both Stedin and Liander (DSOs) have indicated that LV-transformers are ideally kept below 80% of the maximum capacity, translating to 320 kW (Int 2; int 4). This is a clear constraint voiced by the DSOs and while the objective is to alleviate violations of load or voltage level, it is a constraint that any control actions taken must not create new power quality issues.
There are also power flow constraints, (since electricity follows the laws of physics) so flexibility is only effective if located electrically at or upstream of the bottleneck. This limits which batteries can help with a given congestion instance. Thus location specificity is a key technical constraint the solution must match flexibility offers to the correct grid location. In GOPACS, this is handled by requiring EAN codes for each offer to ensure the effect flexible asset is connected to the correct transformer/node (Chondrogiannis et al., 2022).

Communication and control infrastructure:

Reliable two-way communication must exist between the DSO/aggregator control systems and the residential batteries. If real-time control is envisioned, latency and communication failure tolerance become constraints. A lack of existing ICT infrastructure at the LV grid level is a known challenge. DSOs thus have limited insights in what is happening in the grid (van Someren, 2025; CE Delft, 2025; Int; 2). The design is thus constrained by the need to deploy new sensors or controllers (with associated time and cost), or by a lack of total insight in to what is happening.

5.2.2 Market and economic constraints

The success of using residential batteries for congestion management depends on market dynamics that pose several constraints.

Availability and liquidity of flexibility:

There must be enough willing participants in the target areas to actually meet the DSO's congestion relief needs. In areas of severe congestion, if there are too few batteries (or flexible loads), the proposed solution may simply not have enough capacity to be effective. Conversely, if there are many potential providers, the design must handle competitive procurement and prevent any single actor from dominating. A constraint to consider here is that the current penetration of residential storage in the Netherlands is growing fast, but still limited in capacity as the residential market is just emerging (Hutters, de Boer, 2025). Therefore, initially the volume of flexibility from home batteries might be quite small in many neighbourhoods. This limits the impact in the short term and means the design should be scalable for future growth.

Economic viability for participants:

Another constraint is of economic nature. The compensation offered for flexibility must outweigh the costs or lost opportunities for those providing it. If electricity prices are very volatile (day-ahead, imbalance, or intraday), batteries can earn money through arbitrage or frequency regulation via their BRP; an aggregator will only dedicate the battery to DSO congestion service if the payment is competitive with those alternatives. Unless there are other factors that force the battery to be deployed for local congestion. This makes the relative value of flexibility in different markets a constraint. The Dutch experience with GOPACS highlights some of these issues: it combines with the existing intraday market, allowing flexibility providers to place two prices (a general market price, and higher congestion price) (Chondrogiannis et al., 2022). If the congestion price cap is too low, few bids will appear. Therefore, the pricing mechanism design is constrained by incentive compatibility: the design of a market should be such that participants have an incentive to act in a way that aligns with the overall goals of the system.

Risk of market power:

If in a given area one aggregator signs up most of the flexible homes, that aggregator could have an outsized influence. It could bid up prices knowing the DSO has limited options (DSO has to take the congestion bid to prevent an outage). The mechanism needs constraints such as price caps or procurement from multiple sources to mitigate this. Currently, a DSO can spend €1,02 per MWh they transport (Pató, 2024). The Dutch ACM in approving congestion management, requires DSOs to choose cheapest bids and also to justify that engaging flexibility is cheaper than grid expansion in the short term. If the flexibility demanded becomes too expensive due to the aggregator driving up prices, the scheme would breach economic constraints and be halted.

5.2.3 Consumer protection and social constraints:

Because a congestion management solution with residential batteries involves end-users, constraints to protect consumers and ensure social acceptability are paramount.

Privacy:

Privacy is a key concern, using home batteries for grid purposes could involve collecting real-time usage data from homes or sending control commands to devices in homes. The solution design must therefore adhere to privacy constraints: data collection should be minimized and anonymized where possible. In the Netherlands, smart meter data by default is read at most daily; more frequent readings (15-min or real-time) require opt-in consent due to privacy laws. This constrains the DSO or aggregator from pulling high-resolution data from every home and limits monitoring.

Linked to privacy is cybersecurity as another modern constraint. Any ICT system could be a target for hacking or misuse. A breached control system could theoretically send false signals to batteries, either damaging them or causing grid disturbances. Therefore, robust encryption, authentication, and fail-safes must be in place. E.g. by adhering to ISO/IEC 27001 and IEC 62443, providing a general framework for information security management and focussing on cybersecurity for industrial automation and control systems (IACS) (Hutchinson, 2024).

Fair access and non-discrimination

These are social constraints related to fairness. All consumers who are capable of providing flexibility should have a reasonable opportunity to participate and benefit as described in the netcode (Overheid.nl, 2025). The program should not, only recruit customers in affluent areas or those with a certain technology brand. In our context, consumer consent is another strict constraint: residential battery owners must opt in to any control or market program. Contracts must be transparent about the frequency and duration of possible interventions, and consumers should retain the right to override or exit the program with reasonable notice.

In conclusion, these constraints, technical, market, and consumer-related form the boundary conditions for the conceptual design. They narrow the design space by ruling out infeasible or undesirable options. For instance, a design where the DSO directly remote-controls all home batteries at will is ruled out by legal and social constraints; a design that over-cycles batteries is ruled out by technical and consumer constraints.

6 Design space of solution options

This chapter explores the solution space for enabling dynamic congestion management with residential battery storage. The solution space encompasses the full range of feasible mechanisms that can mitigate distribution grid congestion in real-time or near-real-time, within the objectives and constraints defined earlier in this thesis. In conceptual terms, the design space represents a superset of all design components and variables that satisfy the system's goals and boundary conditions. Thus, designing a solution is equivalent to selecting an instance in the design space that meets the objectives and constraints (Mir Mohammadi Kooshknow, 2022). The scope here is focussed on operational measures (as opposed to long-term grid expansion) that dynamically adjust demand or injection from residential batteries to relieve local network overloads. Key objectives guiding this space include maintaining network reliability, maximising existing grid utilisation, ensuring fairness to consumers, and cost-effectiveness. Key constraints include technical limits (thermal capacity, voltage bounds), the regulatory framework in the Netherlands (which mandates non-discriminatory and market-based network management), and practical considerations like customer acceptance and data privacy.

6.1 Solution space definition

This section defines the design space for dynamic congestion management solutions using residential battery systems in the Dutch electricity network. The design space encompasses all adjustable technical, economical and institutional variables that determine how a congestion management scheme can be configured. By identifying these key design variables, without yet favouring any particular solution, we can describe the range of possible system configurations. Such design choices strongly influence the performance and feasibility of congestion management mechanisms. A clear definition of this space is therefore crucial before proceeding to evaluate specific designs (which will be the focus of Section 6.2). In the following, the main categories of design variables are presented, along with their relevance to system performance and stakeholder constraints.

6.1.1 Pricing mechanisms and tariff structures

The first fundamental design variable is the pricing mechanism used to signal or induce flexibility to aggregators. This refers to how electricity network usage is priced or incentivised under congestion conditions. Pricing schemes can be:

1. Static (fixed or preset tariffs)
2. Dynamic (time-varying tariffs tied to grid conditions)

Static approaches such as flat network fees or time-of-use tariffs, are simple and predictable for consumers, but they cannot adapt to unforeseen congestion events in real time. Dynamic pricing, on the other hand, adjusts charges or credits based on actual or forecasted loads. Well-designed dynamic tariffs can encourage batteries and other assets to dispatch at times that alleviate bottlenecks. However, they also expose consumers to price uncertainty and risk.
Another pricing design aspect is the distinction between regulated tariffs and market based prices. Regulated network tariffs (static and dynamic) are administratively set by the DSO or

regulator; they provide clear and stable price signals, and any congestion costs or savings flow through the tariff structure. End-users risk high charges during congested periods, but benefit from simple and cost-reflective charges during stable times. In contrast, market-based pricing would let the price of flexibility be determined through bids and offers in a market or auction for congestion relief. This shifts price risk to the DSO but can harness competition to find lowest-cost solutions.

Besides the temporal nature and the origin of the price, another important aspect is the direction of the payment. Does the user pay a higher price during congestion to the grid DSO, or does the DSO pay the user for providing flexibility?

6.1.2 Control architecture: Direct vs indirect

Another key design variable is the control architecture for managing congestion, i.e. how the flexibility of residential batteries is activated and by whom. Broadly, there is a spectrum between direct control and indirect control methods.

In direct control, the DSO or designated party (can be an aggregator) can directly curtail or dispatch batteries when grid congestion arises. This typically involves an automated control signal or switch that overrides normal operations at critical moments. This direct dispatch ensures a high degree of reliability as the DSO themselves can guarantee the response to overloads.

By contrast, indirect control uses economic signals and incentives rather than direct commands. In this model, the DSO influences battery behaviour through price signals or market mechanisms. The decision to charge or discharge is in the hands of the end-user or their aggregator. This preserves consumer choice and autonomy, but shifts risk in the direction of the DSO. The DSO is no longer guaranteed a certain action and bears the risk of the flexibility not materialising when the incentive is seen as insufficient.

Thus, the control architecture must balance network reliability with customer autonomy. Direct control offers certainty at the cost of intrusiveness and technical complexity, whereas indirect control is more decentralized and market-driven but requires carefully designed incentives (and perhaps slightly over-provisioning of flexibility) to ensure congestion is actually mitigated.

6.1.3 Timing and frequence of control signals

The temporal dimension of the solution, when and how often control actions or price signals are issued, is another essential part of the design space. Time choices range from long-term and scheduled interventions to rapid real-time operations. ADSO might manage congestion through day-ahead planning: forecasting next-day peak load on a feeder and sending a signal the evening before to schedule batteries accordingly. Alternatively, the DSO could operate in near-real-time, monitoring the network and dispatching flexibility from batteries on short notice as congestions actually arise. Between these two options intermediate approaches exists such as intraday re-planning or static ToU schemes based on typical congestion hours.

The choice of timing has significant implications for effectiveness and integration with the other markets. Short cycles and real-time signals increase reliability and precision. This is because short control cycles and real-time signals reduce the risk of error from forecasts. As the timeframe moves from static to (near) real-time the ability to alleviate unpredictable congestion improves. The implementation however comes with higher complexity and limitations. Furthermore, the lack of advance notice in a purely real-time scheme prevents an ex-ante approach, meaning flexibility can only address problems as they happen, primarily

through postponing or curtailing load, rather than proactively bringing consumption forward to pre-empt issues.
By contrast, day-ahead or hour-ahead signals allow more proactive scheduling potentially achieving a more optimal load distribution over time, as battery activity can be planned ahead. The drawback is that forecasts might err: if actual conditions deviate, a day-ahead scheme might call for unnecessary battery actions or fail to prevent a surprise peak.
It seems logical to combine time frames in the solution. Timing and frequency decisions must balance the improved efficacy of short-term control against the feasibility and predictability provided by longer-term planning.

6.1.4 Voluntary or mandatory activation

The activation mechanism refers to the way batteries are enlisted and triggered: voluntary or mandated participation. This variable determines the degree of obligation placed on an aggregator or owner of assets to provide flexibility. Purely voluntary schemes leave participation to market forces or incentives. Aggregators or asset might opt in to a dynamic tariff program or sign up with an aggregator if they expect to benefit, but they are free to opt out or ignore signals. Freedom and autonomy are respected but leave the DSO at risk. The DSO cannot be certain how much flexibility will be available during a congestion event.
On the other end exists mandatory or conditional participation, which can be enforced in several ways. DSOs already require large consumers or generators to curtail output when instructed as a condition of grid connection. Setting up contracts with 'lighter' connections for flexibility would be the next step. Mandatory activation guarantees that the DSO can call on a minimum level of flexibility, improving reliability during critical periods. Yet it must be implemented in line with legal and fairness constraints. Participants under obligation typically must be compensated at regulated rates or via market prices when their assets are curtailed. Obligatory participation also risks discouraging investment or investments.
Therefore, a middle ground is often sought: contractual commitments where users voluntarily agree in advance to provide flexibility under certain conditions. Capacity restricting contracts (CBCs) are an example of this: connections agree to a maximum use level during peak times in exchange for a financial reward. In sum, the activation mechanism design must consider how to secure sufficient participation to reliably manage congestion while respecting consumer rights and maintaining trust.

6.1.5 Spatial granularity and localisation of control

Granularity in this context refers to the geographical or electrical scope at which congestion management measures are applied. Design choices range from coarse, system-wide approaches to highly localized interventions. The solution could be broadly applied for instance, a dynamic tariff that raises prices for an entire DSO region during certain peak hours, regardless of exactly which location has an issue. Alternatively, it could be locationally granular, targeting specific transformers that are experiencing congestion. The appropriate level of localisation is a crucial design variable because distribution network constraints are often highly localised.
Using localised signals improves effectiveness and economic efficiency: fewer connections are affected by a congestion managing act when the location on the act is very specific. Areas without congestion are not constrained. High granularity does come at a cost. Administrative and computational complexity is high as it needs to be done for more/smaller segments

individually. More importantly, it can introduce equity concerns. Customers in congested zones would consistently face higher network charges and can be perceived as discriminatory. By contrast, less granular approaches treat larger areas uniformly, as is done in the current situation. This is simpler and avoids discrimination by location, but it may be less efficient. . Many users might be signalled or controlled even though their specific branch of the network is not overloaded. It can also decrease the incentive for those in congested areas as signals are averaged out with other non-congested areas. Thus, the spatial granularity must be chosen with care, balancing the targeting efficiency of localisation against the practicality and fairness of broader-based schemes

6.1.6 Market roles and actor responsibilities

The institutional framework is another defining element of the design space. The current system has established roles such as the BRP, the BSP and emerging roles like the CSP. A key design question is whether these roles are kept separate or unified in the context of distribution-level congestion management.

In some design configurations, an independent aggregator acts as a CSP/BSP for the DSO's congestion needs, while the customer's BRP remains a distinct party. This separation of roles leverages specialisation (aggregators focusing on flexibility, suppliers on energy provision), but it raises coordination challenges. Actions by the aggregator will lead to imbalances in the portfolio of the BRP, this will lead to the BRP incurring imbalance charges for the deviation. Currently, the aggregator informs or compensates the BRP. The Dutch system is evolving in this area: new settlement methods are being proposed so that when a CSP activates flexibility, TenneT and the DSO coordinate to adjust the BRP's position automatically, minimising the need for bilateral contracts.

Alternatively, a design might unify some roles to streamline operations. For instance, the aggregator providing congestion management could also be the BRP for those customers, meaning the same entity handles both energy supply and flexibility. This is the case for Frank Energie and other energy suppliers offering flexibility in imbalance and congestion markets. In that case, any adjustments made for congestion are internalised in the aggregator-BRP's portfolio, avoiding the imbalance issue. It may however reduce innovation if only energy suppliers are allowed to offer congestion services to its customers as independent aggregators are excluded.

The introduction of the CSP role in the Netherlands reflects a move to incorporate a new actor dedicated to congestion management. Under current rules, even an aggregator that is already a pre-qualified BSP for ancillary services must obtain separate recognition as a CSP to participate in DSO congestion management platforms. '

In summary, defining market roles involves deciding who can call on flexibility (DSO alone or also TSO/BRP), who provides it (the battery owners, their supplier, or a independent aggregator), and how these actors interact. The choices affect the complexity of implementation and must align with stakeholder constraints such as regulatory definitions of roles, licensing, and the principle of technology-neutral and actor-neutral access.

6.1.7 Flexibility procurement method

A final broad category of design variables is the flexibility procurement method. There are multiple options for procurement, each with distinct implications for market dynamics and stakeholder roles.

- **Contractual procurement (ex-ante):** The DSO secures flexibility in advance through contracts or tariffs. For example, it may offer a capacity limitation contract to certain customers or aggregators, paying them a fixed amount to agree to a maximum consumption level during peak periods. Similarly, a DSO could implement a subscription based network tariff where consumers pay lower fees in exchange for non-guaranteed access. These arrangements are made ahead of time and provide reliability, this also makes them possibly inefficient.
- **Market-based procurement (ex post)**: The DSO obtains flexibility through a market closer to real time. In this configuration, flexibility is traded on a platform. This is done on higher grid levels through GOPACS. Market based procurement is attractive for its efficiency: prices are determined by supply and demand, so the DSO needs to pay just enough to get the needed relief. The downside is that the availability of flexibility bids is not guaranteed.
- **Centralised or direct dispatch:** In some designs, rather than a market or preset contract, the DSO might manage flexibility in a centralised way, effectively treating it as an extension of grid operations. This approach overlaps with the direct control architecture discussed earlier. Some systems, enabled by prior agreements for dispatch rights, allow DSOs last-resort right to curtail or increase loads under defined conditions. It guarantees response and speed but raises questions of transparency and non-discrimination.

A hybrid approach combining aspects of all of the above seems most reasonable. DSOs have long-term contracts for baseline levels of congestion and balancing services and then use markets to handle additional congestion/imbalance situations.
To summarise, the method by which flexibility is procured is a major design choice shaping the congestion management solution. It determines economic efficiency, the certainty vs. flexibility trade-off, and how engaged stakeholders will be.

Concluding this first section, the design space is defined by a set of interrelated variables: pricing and incentives, control structures, temporal and spatial scope, participation rules, actor roles, and procurement approaches. Each category of design choice influences system performance (reliability, efficiency, cost-effectiveness) and must be gauged against stakeholder and regulatory constraints (fairness, simplicity, compliance, security).

6.2 Solution candidate approaches

Based on the above identified variables, I identified six plausible solution directions for congestion management leveraging residential battery storage. They range from market-driven pricing mechanisms to direct control strategies.

6.2.1 Dynamic Locational marginal pricing (DLMP)

DLMP is a market-based pricing strategy that extends locational marginal pricing from the transmission level to the distribution grid. It calculates electricity prices at a granular level,, both in time (e.g., every 15 minutes) and space (e.g., per transformer), reflecting not just energy prices, but also local network congestion and losses.
When a transformer is congested for offtake, the local electricity price increases. This price signal incentivises batteries to discharge and reduce demand on the grid. Conversely, when

solar oversupply lowers prices and a transformer is congested for injection, batteries are incentivised to charge. Batteries thus respond autonomously to price signals that indicate the value of congestion relief. The payments in DLMP can happen in both directions.
DLMP makes the following assumptions:

- Advanced metering infrastructure (smart meters), communication systems, and real-time price calculation tools are required.
- Customers or their battery controllers respond rationally to price fluctuations.
- A DSO-operated local market or tariff mechanism is in place.
- Regulatory approval for dynamic pricing.

It has several positive and negatives to note: DLMP maximises social welfare, is highly efficient, and preserves customer autonomy. It is also complex to implement; not yet deployed at distribution level in the Netherlands and price volatility could affect vulnerable customers. Theoretically DLMP is hard to critique, but it is institutionally and technically challenging.

6.2.2 Local flexibility markets

Local flexibility markets enable DSOs to directly procure congestion relief by purchasing short-term flexibility from distributed assets such as residential batteries. Through platforms like GOPACS, DSOs post congestion alerts (e.g., reduce load in a specific region during a specified time window), and aggregators submit bids offering to adjust consumption or generation in return for compensation.
When congestion is forecasted, the DSO initiates a market call. Participating aggregators respond with offers specifying the amount of flexibility they can provide and at what price. The most cost-effective bids are selected, activated, and financially settled via the platform. This creates a local redispatch mechanism at the distribution level, analogous to how TSOs manage transmission congestion. The direction of payment is thus from the DSO towards the aggregator.
This approach builds on market principles, ensuring that congestion is resolved efficiently through competition. It aligns well with current Dutch energy policy, which emphasises decentralized, market-based solutions and flexibility. Initiatives like GOPACS and DSO-led pilots already signal movement in this direction. The option assumes the following:

- Sufficient flexible assets must be available in the congested area, typically through aggregators.
- There must be clear coordination between DSOs and market actors to avoid conflicting services (e.g., frequency control).
- ICT infrastructure is required for real-time communication and measurement.
- Regulatory support is essential to allow and incentivize participation.

Local flexibility markets are among the more mature and practical options. They effectively balance efficiency and control and are already being tested and implemented in the Netherlands.

6.2.3 DSO override switch

The DSO override switch represents a centralised and more direct form of congestion management. Here, DSOs are equipped with the authority and technical means to remotely control residential batteries under specific grid conditions. This could involve halting battery charging, initiating discharging, or completely curtailing their operation.

Control could be automated or manually dispatched from the DSO's control centre, and often follows a "traffic light" framework: under green, devices operate freely; under amber, voluntary curtailment is requested; under red, DSOs can override control to protect grid integrity. Unlike market-based approaches, this system relies on preconfigured emergency protocols and gives DSOs certainty of response during critical periods. In return for these protocols the DSO pays the aggregator a beforehand agreed upon amount. It assumes the following:

- Participating batteries are equipped with interoperable smart inverters and communication interfaces.
- Legal frameworks must authorise DSOs to override customer devices in predefined emergency scenarios.
- Customer acceptance is crucial, especially if direct control limits their ability to use stored energy.
- Standardised protocols must ensure reliable and secure control.

Although this is not commonly used in the Netherlands, the override switch can provide a reliable back-up mechanism. While it is not compatible with a liberalised energy market, it does serve as a valuable safety net in.

6.2.4 Zonal restrictions & flexible connections

Zonal restrictions involve managing congestion by embedding usage constraints directly into grid connection agreements. In congested areas, DSOs may offer non-firm connections, limiting when and how much a battery can draw from or feed into the grid. These arrangements are often formalised through flexible connection contracts or CBCs, where the customer agrees in advance to reduce usage during peak times or limit export capacity. This contract form provides the owner of the connection of payments by the DSO, that essentially materialise as a discount on the regular grid tariff.

For instance, a battery owner might agree not to charge during 5–8 PM or to reduce feed-in capacity by 15% when congestion is forecasted. These restrictions can be static or dynamic. While less precise than real-time markets, zonal restrictions offer predictability and allow DSOs to approve more connections without risking grid overload. Zonal restrictions assume:

- Customers are willing to accept reduced access to the grid in return for benefits (e.g., lower tariffs or faster connection).
- DSOs must be able to accurately identify congestion-prone zones and communicate limits.
- Enforcing dynamic restrictions may require monitoring via smart meters or control interfaces.

Zonal restrictions provide a low-risk solution when real-time systems are unavailable. They can lead to inefficiencies and curtailment beyond what's necessary, but they offer a guaranteed option to limit grid stress and are already implemented by Dutch DSOs for 'heavier' connections.

6.2.5 Dynamic tariff adjustments

Next, dynamic tariff modulation uses time- or location-dependent pricing in network tariffs to influence battery behaviour. By making electricity more expensive during known congestion periods and cheaper (or even negative) when the grid is underused, DSOs can economically encourage battery owners to shift consumption and alleviate grid pressure without direct intervention. Similar to DLMP, payments can run in either direction but most of the time money will still flow from customer/aggregator to the DSO. Unlike DLMP, which is fully dynamic and granular, tariff modulation can be implemented through simpler structures such as time-of-use rates, critical peak pricing, or regional pricing bands. The dynamic tariff adjustments are set for a longer period of time and can be revised periodically (perhaps each month) to see if the highest prices still match the congested moments. One single congestion event does not instantaneously adjust the tariff. This option has the following assumptions:

- Consumers and assets are sensitive to price differences and capable of automated responses.
- Regulatory approval is required for adjust grid tariffs.
- Tariff design must be fair and transparent to avoid penalising vulnerable users.
- Smart meters are needed to track consumption by time period.

Dynamic tariff modulation is an attractive option due to its relative simplicity, transparency, and scalability. It fosters distributed decision-making and minimises transaction costs. However, its effectiveness depends on customer responsiveness and may need to be complemented by more direct or market-based measures. Also, the time needed for implementation is long since the set prices need to be reasonable and may not be disproportionally disadvantageous for certain consumers.

6.2.6 Dynamic capacity tariff

Lastly, a dynamic capacity tariff is a grid charging scheme that bases consumer fees on maximum power usage (kW) rather than energy consumed (kWh). In essence every user is allotted a maximum peak capacity, and charges (or limitations) are tied to that capacity. However, this tariff only differentiates pricing or imposes restrictions during periods of local grid congestion. Under normal conditions, all consumers pay the standard grid tariff and can use electricity up to their usual capacity with no penalties or limits. However, in a congestion event, the tariff becomes active: consumers who use power beyond their allotted capacity threshold either incur and extra charge or have their demand temporarily curtailed to the agreed capacity level. This way, only at times of actual network stress do heavy users face higher costs or restrictions, while at all other times they enjoy unrestricted usage at the normal tariff. Payments here follow a similar pattern as DLMP and Dynamic Grid tariffs. This last option has the following assumptions:

- Advanced metering or monitoring systems are in place to measure peak kW usage accurately.
- Regulatory approval is granted to apply capacity-based charges dynamically.
- A mechanism exists to identify and declare congestion events in specific grid areas.
- Consumers and assets have the ability to respond to pricing signals.

Dynamic capacity tariffs are attractive because they can encourage peak shaving when and where it is needed. At the same time it avoids penalising consumers for full use of their capacity outside of congested moments. Should the higher price occur during an congestion event, the consumer has the autonomous choice to keep consumer. However, should the consumer then be limited to the agreed upon capacity they lose out on this autonomy.

6.3 Trade-offs between solutions

In comparing the five candidate congestion management solutions, several fundamental trade-offs emerge. Each approach balances different objectives and involves compromises on control, simplicity, and market dynamics. The key trade-offs include:

- **Direct control vs consumer autonomy**

The proposed solutions differ in how much direct power the DSO or aggregator has over the residential batteries. The DSO override switch represents strong direct control and yields high reliability. Yet is comes at the cost of intrusiveness and reduced end-user control. By contrast, *Dynamic tariff adjustments* relies on indirect control: price signals encourage users or aggregators to adjust usage, preserving customer choice. Indirect methods shift the risk onto the DSO as there is no guarantee that a response will happen on the price signal. Here, the dynamic capacity tariff has the middle ground as it can both be direct control (restriction to agreed upon capacity) or indirect control (relying on price responsiveness). Thus, a spectrum exists: direct control offers certainty but is interventionist, whereas price-based or market-based incentives respect autonomy but introduce uncertainty in outcomes.

- **Simplicity vs precision**

There is a notable trade-off between operational simplicity and the precision of congestion management. Approaches like Zonal restrictions & flexible connections or basic time-of-use tariffs are relatively simple and transparent. Dynamic capacity tariffs occupy a middle ground: they are simpler and more transparent than highly granular DLMP, yet they offer more adaptability and targeted impact than static measures by activating only when and where grid stress occurs. However, these simple static measures lack real-time adaptability. On the other hand, more dynamic schemes (e.g. DLMP or Local flexibility markets) offer fine-grained precision, activating exactly the amount of battery flexibility needed at a given moment and location.

- **Centralised vs decentralised roles**

The solutions assign roles and responsibilities either in a centralized or distributed manner. DSO override switch centralises decision-making with the DSO, while Dynamic tariff adjustments and Local flexibility markets embody more decentralised, market-driven control. The DLMP configuration splits responsibilities: the DSO provides granular pricing, while aggregators or devices decide the dispatch. Generally, centralised control yields more predictability for the DSO but conflict with the liberalised market nature of the Dutch electricity system.

- **Predictability vs market-based efficiency**

Predictability is crucial for DSOs who must avoid transformer overload. Contractual or rule-based schemes offer this predictability, but risk being overly conservative and economically inefficient. Dynamic capacity tariffs provide DSOs with relatively high predictability, while leaving consumers flexibility to manage their demand. In contrast, market-based methods aim to identify and activate the least-cost solutions dynamically. These are more economically efficient and allow aggregators and consumers to monetize their flexibility, but provide less guaranteed performance. Price-based approaches (DLMP, Dynamic tariff adjustments) rely on voluntary, decentralised actions that optimise for cost and user preference but don't guarantee congestion relief unless market responses are highly elastic and well-designed.

- **Short-term ease vs long-term scalability**

Some solutions can be deployed relatively quickly using existing tools and contracts e.g. Zonal restrictions & flexible connections or Dynamic capacity tariffs (both used for larger users already). These are useful for DSOs facing urgent capacity constraints but may not adapt well to future systems with widespread flexible assets. DLMP and Local flexibility markets are more scalable: they can adapt to high volumes of devices and granular grid data. However, their implementation requires regulatory evolution, digital infrastructure, and new market roles. Choosing a solution often involves balancing near-term congestion relief with long-term strategic fit.

- **Implementations cost vs regulatory compliance**

Solutions vary in their technological and organisational cost. DSO override switch requires real-time control systems, device interoperability, and secure communications, raising implementation barriers. Moreover, it may be non-compliant with current Dutch regulation. By contrast, Dynamic tariff adjustments and dynamic capacity tariffs could both be introduced via regulatory reform and smart meter data, using existing billing frameworks, but may take longer to implement due to policy constraints and equity concerns. Local flexibility markets and DLMP require investment in forecasting tools, transaction platforms, and stakeholder coordination, but align with market-based policy directions and may be more resilient to future system demands.

6.4 Selection criteria

Derived form Chapter 5, the following criteria are used to assess solution performance:

- Effectiveness in reducing transformer overload

This criterion gauges how reliably a solution alleviates local grid congestion at critical times. Any proposed measure must actually solve the problem to be considered viable. Solutions are judged on their proven ability to curb strains under worst-case conditions. In practice, this means the method should consistently keep loads within safe operating limits during congested periods, ensuring network reliability and avoiding outages.

- Fairness and consumer acceptability

Because congestion management influences how people use electricity, equity and acceptance are key. A fair solution is one that distributes cost and benefits in an even-handed way, without unfairly burdening any single group of consumers. Policymakers often bring up the ''polluter-pays'' principle. At the same time, mechanisms must be designed with social acceptance in mind: if a scheme is perceived as punitive or beyond consumers' control, it will face resistance.

- Compatibility with the Dutch legal/regulatory framework

This criterion is about ensuring legal feasibility: the proposed measure should either be allowed under current electricity laws and grid codes, or be realistically achievable via minor regulatory adjustments, that are in line with previous policy adaptations.

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- Economic efficiency and revenue preservation

This criterion examines whether the solution addresses congestion in a cost-effective manner and how it impacts the financials of stakeholders. An economically efficient solution minimizes the total system costs of managing congestion. The chosen strategy should ideally relieve congestion at the least cost to society. Additionally, "revenue preservation" highlights that the approach should not jeopardise the DSO's ability to recover incurred costs or unfairly erode the income possibilities of other parties.

- Implementation feasibility (ICT and data requirements)

This criterion addresses the practical deployability of the solution. A theoretically brilliant solution may fail if it requires complex, real-time control or data that the current system can simply not provide. Thus, proposals are evaluated on their complexity and the readiness of necessary tools. For example, using smart-meter data is relatively straightforward now that over 90% of Dutch households have smart meters.

- Institutional fit (Roles of the DSO, aggregator, consumer and ACM)

Finally, the solution is assessed for how well it aligns with the institutional structure of the electricity sector. An ideal congestion management method will slot into these established roles without requiring a radical overhaul. For instance, a dynamic network tariff can be implemented by the DSO via its existing tariff-setting authority

Table 4 shows each of the options scored against main criteria from Chapter 5. They are derived from the trade-offs and represent how each solution is expected to perform relative to the selection criteria.

Table 4: Qualitative comparison of solution configuartions against key criteria from Chapter 5 ranked High, Medium, or Low.

Criterion / solution	DLMP	Local flexibility market	DSO override switch	Zonal restrictions & flexible connections	Dynamic tariff adjustments	Dynamic capacity tariff
Effectiveness in reducing overload	Medium/High	High	High	Medium	Medium	Medium
Fairness & consumer acceptability	Medium	Medium/high	Low	Medium	Medium	Medium
Regulatory compatibility	Medium	Medium/high	Low	High	Medium	Medium/high
Economic efficiency & revenue preservation	Medium/high	High	Medium	Low	Medium	Medium
Implementation feasibility	Medium	Medium	Low/Medium	High	Medium	Medium
Institutional fit	Medium	High	Low	Medium	High	High

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6.4.1 Preliminary exclusion of less-suited solutions

Based on the trade-offs and comparison above, the following two solutions are excluded from further evaluation in Chapter 7:

- DSO override switch

Despite the technical effectiveness the solution is not acceptable in the liberalised Dutch market. This has to do with significant regulatory barriers and the heavy toll on consumer autonomy.

- Zonal restrictions & flexible connections

While this is a simple and legally permissible, this approach leads to economic inefficiencies at it lacks competitive procurement or price-based selections of flexibility. Instead, it limits usage based on location or connection agreements and because of that it loses flexibility value. This makes it unsuitable as a long-term strategy.

The remaining four configurations, Distributional locational marginal pricing, Local Flexibility markets, Dynamic tariff adjustments and Dynamic capacity tariffs will be evaluated in more detail in the next chapter.

7 Solution design evaluation

In this chapter the four shortlisted congestion management solutions are evaluated qualitatively against the key objectives and constraints that are evaluated in Chapter 5. These criteria include: 1) Effectiveness in reducing transformer overload, 2) Fairness and consumer acceptability, 3) Compatibility with Dutch/EU legal and regulatory frameworks, 4) Economic efficiency and stakeholder revenue preservation, 5) Implementation feasibility, and 6) Institutional fit within the current market roles. The chapter is summarised by a table presenting the performance of the four solutions, ranked High, Medium, or Low.

7.1 Effectiveness in reducing overloads

The Distributed Locational Marginal Pricing approach is theoretically very effective, and is thus given a Medium/High score. It provides granular price signals that reflect real-time capacity scarcity in the grid. A transformer overload creates a spike in the local electricity price and thereby incentivises connected batteries to curtail consumption or discharge stored electricity. The dynamic pricing is able to react quickly to network conditions and coordinate multiple batteries autonomously, flattening peaks and relieving strain (Almeida et al. 2021). If all actors respond rationally to the price, DLMP is able to achieve an optimal re-dispatch similar to an ideal market outcome. However, its effectiveness in practice may be somewhat lower than the ideal: price-based schemes rely on voluntary response, so there is no guarantee that enough consumers or aggregators will adjust their behaviour in time. The DSO thus bears the risk that a price spike might not yield sufficient load reduction, especially if demand is price-inelastic or if automated controllers are not in place. DLMP is currently applied and discussed mostly in the North American context (Hennig, 2023).

An effective solution must reliably alleviate transformer overloads at critical times. Among the remaining options, Local flexibility markets achieve the highest effectiveness because the DSO can directly procure the exact amount of load reduction or injection needed to relieve a local constraint (Hennig, 2023). By calling on flexibility from residential batteries or other resources in the area, a local flex market provides targeted and guaranteed congestion relief. This direct procurement approach yields a High effectiveness score. It mirrors how TSOs manage transmission congestion via markets and has already been piloted in the Netherlands (e.g. GOPACS) to successfully mitigate distribution bottlenecks through competitive bids. It does come with a drawback, as it assumes that sufficient participants are available per location.

Dynamic tariff adjustments are ranked Medium in effectiveness. Like DLMP, it relies on indirect control: The DSO tries to influence behaviour by raising grid charges during anticipated congestion periods, hoping that consumers or their aggregators respond to avoid high fees. Well-designed peak tariffs can effectively flatten local demand curves and improve reliability (Hennig, 2023; CEER, 2020). However, dynamic tariffs share the same fundamental limitation of relying on voluntary compliance. If customers do not change consumption (due to habit, necessity, or lack of awareness), the congestion may not be alleviated. Unlike a market procurement, there is no contractual certainty of relief, only a financial incentive. Thus, while dynamic tariffs contribute to congestion management (and relatively easy to deploy broadly), their effectiveness is not as assured or fine-tuned as a dedicated flexibility market intervention.

Dynamic capacity tariffs are assessed to provide a Medium level of effectiveness in alleviating local grid congestion. By design, this scheme incentivises consumers to curb peak demand during critical periods: when a congestion event is declared, any usage above the subscribed capacity incurs steep charges or is physically limited, directly reducing strain on transformers and cables. Simulation studies indicate that such tariffs can successfully resolve or prevent overloads if priced or enforced strongly enough (Van der Holst et al., 2023). Similarly, an IEEE simulation of a Dutch neighbourhood found that a capacity subscription tariff helps to prevent transformer overloading under growing EV adoption (Hennig et al., 2020). However, as an indirect mechanism, it still shares some limitations with other price-based approaches. If consumers or aggregators do not respond adequately to the price/limit signal, residual congestion could occur.

7.2 Fairness and consumer acceptability

Any congestion management strategy must balance its effectiveness with fairness and public acceptance. This includes avoiding any undue harm to certain customer groups ensuring that access to electricity remains equitable.

The DLMP approach receives a Medium fairness score. DLMP by design introduces locational price differences: neighbourhoods or nodes with a congested transformer will experience higher electricity prices than those in unconstrained areas.
On one hand, this is economically efficient and cost-reflective, it signals the true cost of using the grid in a congested location. This adheres to a fairness concept of "cost causality." Customers in high-cost areas can also respond by adjusting usage or investing in local solutions to lower their bills, thus they have agency in the face of price signals (Almeida et al, 2021). However, geographic price discrimination can be socially sensitive. If certain locations consistently face much higher electricity prices, it may be perceived as inequitable or politically unacceptable. Consistent higher prices in one location can be solved by grid upgrades, but that is precisely what this research is trying not to do. Unlike dynamic tariffs which vary by time but not by place for a given DSO, DLMP could mean neighbours served by different transformers pay different rates for the same electricity, simply due to grid constraints. This could draw public criticism unless it's very transparently justified by cost savings. DLMP is also quite complex as it produces highly volatile, real-time prices. This complexity can confuse the average customer, especially since fixed electricity rates are still the norm. DLMP also deals with the same issue as Dynamic tariff adjustments in the sense that vulnerable customers may not be able to respond to DLMP signals.

For Local Flexibility Markets, fairness is a nuanced issue, here judged as Medium/High. In such markets, the DSO pays willing participants to adjust their consumption or production. This approach is voluntary, only those who have flexible resources and choose to offer them will participate. From a consumer autonomy standpoint, it is quite fair on one side: nobody is involuntarily curtailed in the sense that users without assets are not penalised for not responding to a curtailment request. Just those who do respond to the flexibility request are financially compensated for the service they provide. This compensation mechanism can

improve acceptability, since participants feel they are earning income or savings by helping the grid, rather than simply being penalised for consumption. Additionally, by resolving congestion through market payments, supply interruptions can be avoided for everyone, which is a collective benefit. The flip side is that flexibility markets may introduce disparities different consumer groups. Households with assets like batteries or EVs (mostly higher-income early adopters) can profit from these schemes, while those without flexible assets see none of the payouts but could ultimately bear the costs since congestion management costs are socialised across network users. In other words: wealthy prosumers earn revenue by adjusting load, while less wealthy consumers effectively subsidise the payments.
Furthermore, there is a market power dimension: if a single aggregator or a few large customers in a neighbourhood control most of the flexible load, they could strategically bid high prices for curtailment. This risk of gam2024ing might undermine public acceptance (Hennig, 2023).

The Dynamic Tariff solution poses some fairness concerns, earning it a Medium score on this criterion. On one hand, time-varying network tariffs can be designed transparently and applied uniformly to all consumers in an area, which is in principle fair: those who use the grid during congested periods pay more of the associated costs, while those who are flexible and reduce usage are rewarded with lower bills (Gorenstein Dedecca et al. 2025). The cost-causality principle aligns with equity, customers contributing to peaks pay for the strain they cause. Moreover, dynamic tariffs preserve consumer choice (no one is forcibly switched off; each user can decide whether to reduce consumption or simply pay the higher price), which improves acceptability compared to any mandatory/direct control. However, a major concern is the impact on vulnerable or inflexible consumers. Some households may be unable to curtail usage during peak tariff windows and could face sharply higher bills, these are for instance people with medical machines. If dynamic network charges are not carefully capped or coupled with protections, they risk disproportionately penalising those who cannot easily shift their demand. A real-world example comes from the Texas 2021 crisis, where real-time dynamic prices led to shockingly high bills for some consumers who were unable to react or unaware of the spikes (Gruber et al. 2022)

The fairness of a dynamic capacity tariff is mixed, earning a medium score on equity and acceptance. It is cost-reflective, following the “polluter pays” principle: heavy users during peak stress periods pay more, while those avoiding peaks benefit from lower charges. This can reduce cross-subsidies, as shown in Norway, where capacity subscriptions improved cost reflectivity and kept most bills stable. The approach avoids penalising off-peak use, offers consumers flexibility in choosing subscription levels, and can feel less intrusive than direct control (Bjarghov, & Doorman, 2018).
However, legitimate concerns arise regarding vulnerable or inflexible users. Households that cannot easily reduce demand during peak hours might be forces to pay for the higher required capacity. Without safeguards, dynamic capacity pricing could disproportionately impact those less able to invest in smart controls or alter behaviour, similar to the worries with time-varying tariffs or DLMP. Complexity of the concept ‘capacity’ is another challenge, as misunderstanding capacity needs could cause bill shocks. Ensuring consumer acceptability will thus require clear communication, user-friendly controls, and perhaps protections for the most vulnerable/exposed consumers.

7.3 Compatibility with legal and regulatory framework

Implementing any of these solutions requires alignment with existing Dutch and EU regulations, or else regulatory changes. But as noted previously, the constraints of current legislation is not taken into account fully, since aggregators are currently not able to act as CSP at all.

The DLMP approach faces the most substantial regulatory challenges, resulting in a compatibility score that is medium at best, and arguably low. DLMP represents a fundamental departure from current practice by introducing real-time, location-specific pricing of electricity at the distribution level. This would be unprecedented in the Netherlands, where even transmission-level pricing is uniform nationwide. DLMP blurs the traditional boundary between network operation and market operation, as it would place the DSO in a position to set real-time prices at individual grid transformers. Under the existing regulatory model, DSOs are expected to act as neutral network operators, while pricing is managed by suppliers and exchanges. Implementing DLMP would therefore require a redefinition of regulatory roles and likely new legislation or experimental legal exemptions. Consumer protection frameworks would also need to evolve to account for the increased volatility and complexity associated with local pricing. DSOs argue that this additional complexity and registration will take a lot of work and explaining (Int 2; int 4), while it will be the energy supplier registering consumption similarly to dynamic prices (Hulshof, personal communication, 2025). Notably, no EU member state has yet adopted full DLMP at the distribution level, leaving Dutch regulators without an existing model to follow.
Furthermore, there is a risk that DLMP is seen as violating the principle of non-discriminatory grid access, particularly if it leads to significant continuous price disparities between regions. While economically cost-reflective, any legal framework would need to ensure it does not undermine affordability or unduly concentrate market influence in the hands of DSOs.

Local Flexibility Markets score Medium/High in terms of regulatory compatibility in the Netherlands, reflecting strong alignment with both European Union and Dutch energy policy. The EU Electricity Directive 2019/944 requires DSOs to procure flexibility services where this is more efficient than traditional grid reinforcement (EASE, 2022). This directive has been transposed into Dutch legislation, enabling DSOs to contract with third parties for congestion relief. The existence of pilot schemes and platforms like GOPACS, where DSOs actively procure congestion alleviation from commercial providers, demonstrates that such mechanisms are not only legally permitted but also actively supported. It aligns well with the liberalised electricity system and does not infringe upon the roles of suppliers. A key regulatory consideration is the need for standardisation and transparency. Fortunately, supportive frameworks such as the USEF protocols and EU-level guidance are being developed, and current legislation does not restrict DSOs from facilitating these markets, provided they remain neutral.

Dynamic Tariff Adjustments have a Medium regulatory compatibility. On the positive side, the concept of time-of-use or dynamic network tariffs is gaining acceptance among policymakers, as demonstrated previously the Netherlands is one of the few countries not using some form of ToU tariff. European regulators (CEER and ACER) have acknowledged that making network tariffs more cost-reflective and time-dependent can send efficient signals and help manage congestion (Gorenstein Dedecca, 2025). Article 18 of EU Regulation 2019/943 mandates that network tariffs must be non-discriminatory and cost-reflective, which may support temporal differentiation provided it accurately reflects actual system costs. The Dutch regulator ACM has expressed openness to tariff reform and has investigated alternatives such as peak charges and time-of-use rates to encourage off-peak consumption (ACM, 2024). Nonetheless, the implementation of a dynamic tariff would require a formal proposal, trials under ACM supervision, and likely some legislative adaptation. This takes valuable time.

Implementing dynamic capacity tariffs appears feasible within the regulatory framework, with a Medium/High compatibility rating under current Dutch/EU rules. The approach builds on the existing concept of capacity-based grid tariffs, familiar to regulators in the Netherlands. The dynamic twist , requires some regulatory adjustments but aligns with the broader trend toward more flexible, cost-reflective network tariffs (Bjarghov & Doorman, 2018). In the Netherlands, DSOs operate under tariff regulations set by the ACM, which could permit a capacity subscription model provided it meets non-discrimination and transparency criteria. European regulators have shown openness to time-varying or capacity-based charges. Most countries already adopt these, as depicted in Figure 4.
One potential regulatory hurdle is ensuring that such tariffs remain neutral and fair. The scheme must be calibrated so that DSOs is still able recover costs, and no customer class is unduly disadvantaged. This will be scrutinised by the ACM. Similar to the dynamic tariff adjustments, dynamic capacity tariffs also requires a formal proposal and trials under ACM supervision. This take valuable time.

7.4 Economic Efficiency and Revenue Considerations

From an economic standpoint, a desirable solution minimises total system costs while not undermining the financial viability of stakeholders. Assuming that the revenue cap remains the same for the DSOs, all options have the same effect on their revenue considerations. A reshuffle does occur in where their revenue is drawn from since the options are focused on "making the polluter pay".

DLMP is rated Medium/High for economic efficiency. Theoretically it is the most efficient of the four mechanisms (Almeida, 2021; Hennig, 2023). By extending nodal pricing to the distribution grid, DLMP ensures electricity prices reflect the true marginal cost of delivery, including congestion and losses. This encourages real-time, location-specific optimal dispatch of demand and flexibility, thereby maximising social welfare. Over time, DLMP could defer costly grid upgrades from less-congested areas and guide DER investments to more-congested areas, the Dynamic capacity tariff does this in a similar manner. It also allows flexible consumers to benefit from low prices when grid conditions permit, preserving consumer surplus without relying on crude curtailment mechanisms. However, this high efficiency assumes rational behaviour and no market manipulation. In reality, some consumers may not respond to price signals, reducing the theoretical gains, while aggregators with local market power might withhold flexibility to inflate prices (Hennig, 2023).

Local Flexibility Markets also score highly on efficiency, often considered economically optimal when well-designed. In this model, DSOs procure flexibility through competitive bidding, selecting the lowest-cost offers to relieve congestion. This leads to the most cost-effective resolution of grid constraints, preserving total welfare while allowing continued use of the grid by others (Hennig, 2023; Kara et al. 2022). Local flexibility pricing provides valuable investment signals: persistently high bids indicate reinforcement of the grid may be worthwhile, whereas low bids justify reliance on flex contracts. It also supports the business case for flexible assets such as batteries, incentivising broader participation and improving system responsiveness. However, the model's efficiency depends on truthful bidding and sufficient competition. Risks include strategic bidding, where dominant providers inflate their offers, or baseline manipulation to game curtailment payments. These inefficiencies can be mitigated through robust market design. Provided regulators enforce safeguards, flexibility markets remain an economically efficient and equitable solution.

Dynamic Tariff Adjustments, by contrast, are rated Medium for efficiency and revenue impact. They improve upon flat tariffs by encouraging consumers to shift usage to off-peak times, enhancing grid utilisation and smoothing demand. This results in fewer peaks, better load factors, and deferred investment needs. Even simple time-of-use tariffs have proven effective in shifting flexible loads such as EV charging (Gorenstein Dedecca, 2025). European studies show that time-differentiated tariffs can reduce system costs and improve efficiency with minimal administrative complexity. However, compared to DLMP or flexibility markets, dynamic tariffs are less granular and precise. Peak pricing windows may not align with real-time congestion, leading to inefficiencies such as unnecessary curtailment or missed constraints. Sophisticated real-time tariffs could improve this but introduce complexity similar to DLMP. Revenue-wise, DSOs might under-recover costs if consumers avoid peak prices too successfully. Regulators typically address this by adjusting allowed revenue over time to ensure financial neutrality. For aggregators and suppliers, dynamic network tariffs may affect profitability, particularly when high grid fees coincide with favourable energy prices, reducing arbitrage opportunities. However, this shift is intentional. Provided congestion-related income is not retained as DSO profit, the approach preserves economic alignment. While less finely tuned than the alternatives, dynamic tariffs offer a practical, low-cost method to improve system efficiency using existing structures and regulatory processes.

Dynamic capacity tariffs offer moderate economic efficiency improvements and generally preserve stakeholder revenues, warranting a Medium score on this criterion. From a system efficiency standpoint, encouraging consumers to reduce peak demand translates into better utilisation of the network and deferred infrastructure investments. Studies have found that capacity subscription-based charges can significantly lower long-term network costs, mainly from reduced reinforcements (Bjarghov & Doorman, 2018). As the cost for network reinforcements are mainly driven by the highest peak (Hennig et al. 2020), this methods targets the main cost driver.

While it generally does not pay aggregators or consumers for reducing load; instead it saves them money (or avoids penalties) if they do so. Aggregators operating batteries can adapt by scheduling charging and discharging to stay within subscribed levels during congestion, maintaining most trading opportunities outside those periods. Though some arbitrage potential is reduced, battery operation remains viable, especially by avoiding high charges during congestion events. The aggregator can still participate in wholesale or balancing markets most of the time, and only has to adjust behaviour during the relatively limited congestion periods. So while not adding a new revenue stream, like a local flex market does, in a Dynamic capacity tariff, like DLMP and dynamic tariff adjustments, overall battery usage remains viable and potentially profitable outside congestion windows.

7.5 Implementation feasibility

When it comes to the practical implementation, DLMP scores Low/Medium while Local Flexibility Markets, Dynamic Tariff Adjustments and Dynamic capacity tariffs all three score Medium. All four solutions require advanced metering and data infrastructure, but to varying degrees.

DLMP is the most technically complex to implement, given a Low/Medium feasibility. To implement DLMP, a DSO needs the capabilities to perform real-time optimal power flow calculations across its network to compute prices at each transformer for each time interval. This is a non-trivial computational task, though advances in computing and state estimation make it conceivable for medium-sized networks. Furthermore, prices must be communicated quickly so that market participants can respond. That implies a two-way communication infrastructure: prices going out, and consumption responses or bids coming back. While smart meters provide consumption data, they typically report on a daily basis, not instantaneously; DLMP would work best with a more responsive communication. Sophisticated IT systems make up a big part of the DLMP's implementation challenge. Cybersecurity is another concern: a system issuing real-time prices and controlling so many devices becomes a critical infrastructure that must be protected from attacks or tampering.
Since no DSO in Europe has implemented DLMP, doing so would be a pioneering effort likely containing a fair share of trial-and-error. The significant IT-infrastructure needs also raise the cost for implementation, luckily some of these upgrades are part of the already started transition toward smart-grids. Yet, compared to the other two options, DLMP is far less mature. Industry reports acknowledge that while DLMP could maximise efficiency, it is complex to implement and not yet broadly deployed. This underscores that significant innovation and experimentation would be required, placing DLMP at a disadvantage in near-term feasibility.

Local Flexibility Markets also rate Medium on feasibility, but require a different set of implementations: market platforms, forecasting, and coordination tools. On the positive side, foundational pieces are already in place. The GOPACS platform in the Netherlands demonstrates a working model of a TSO-DSO coordinated flexibility market for congestion management (Dronne, Roques & Saguan, 2021). While GOPACS currently aggregates flexibility on larger scales, it provides a template that can be adapted for more granular local needs. Implementing a local flex market involves setting up a market platform or using an existing one where offers can be submitted and evaluated. The DSO will need advanced forecasting tools to predict when and where congestion will occur, so it knows when to call for bids that feed into the market. The Netherlands, UK, and some other EU countries have trialed local flexibility tenders with positive results, indicating that the barriers are surmountable with current technology (Dronne, Roques & Saguan, 2021).

For Dynamic Tariffs, the implementation is conceptually straightforward: it leverages the existing smart metering infrastructure that is already rolled out to most Dutch consumers. The Netherlands' high smart meter rollout (>90%) can record interval data and peak demand.

Smart can record consumption in time intervals, which is a prerequisite for any time-varying tariff. All energy suppliers already have a similar billing system in place for dynamic electricity prices, which vary per hour, and will start varying per 15-minutes from October 2025.

Dynamic capacity tariffs are moderately feasible, more complex than static tariffs, but simpler than real-time pricing or new market platforms. Like dynamic tariff adjustments, it leverages smart metering infrastructure. The capabilities needed are: measuring demand against a subscribed limit, signalling congestion events, and optionally enforcing caps. The first two rely mainly on software and communication systems already in place. Physical load limiting may require additional hardware (and will likely face autonomy resistance), but price-based enforcement can avoid this, relying instead on consumer response.
The concept is proven for larger users, where peak limits or demand charges are common. Scaling to households mainly adds data handling and communication challenges, especially for localized congestion events.
What makes this option more difficult than Dynamic tariff adjustments is that the DSO will need to ensure that all consumers know when an event is active. The Dynamic tariff adjustments are not based on one specific congestion event, rather the tariff is set for a certain period. With the Dynamic capacity approach, using over the allocated capacity during a congestion event will lead to incurring higher grid cost for the consumer.

7.6 Institutional fit

This criterion examines how well each solution aligns with the existing or desired roles of actors in the electricity sector and whether it requires uncomfortable shifts in control or market structure. Both Local Flexibility Markets and Dynamic Tariffs score High on institutional fit, whereas DLMP is somewhat lower at Medium.

The DLMP solution has a complicated institutional fit. This approach doesn't have a clear precedent in current institutional arrangements. Rather it cuts across the typical division between network and market operations. In a full DLMP regime, the DSO can be seen as operating a real-time market for energy at the distribution node (transformer) level. This raises questions: Is the DSO becoming a "market operator" for local transactions? How does this intersect with the role of the national market operator (EPEX or Nord Pool) who runs the wholesale market? There is a concern of role overlap or confusion: currently, price formation is the domain of energy markets, not network companies. So, DLMP faces a moderate institutional fit in the Dutch energy system due to the structural changes it would require. To implement DLMP, regulators might need to redefine the DSO's role, allowing it to apply location-based congestion charges, either as part of a dynamic network tariff or as an added price signal on energy. Another challenge exists in the coordination with suppliers. Under the current model, suppliers manage contracts and pricing, which are uniform across locations. DLMP's nodal pricing would complicate this setup, requiring suppliers to handle a multitude of price points and possibly leading to a rethink of retail market operations and balancing mechanisms. DLMP doesn't align cleanly with any existing regulatory category so unless it is formalised as a new tariff methodology it is likely to face resistance. This institutional ambiguity is likely to make policymakers cautious, especially in a mature and carefully structured market like the Netherlands.

Despite these challenges, DLMP is not fundamentally incompatible with liberalised market principles as it uses the most granular form of price signals. From a long-term perspective, DLMP can be seen as the logical end-state of price based coordination as higher granularity increases the performance of congestion mitigation (Hennig et al. 2023).

The Local Flexibility Market approach fits neatly into the current market-oriented paradigm and is therefore ranked High. It essentially creates a new market segment for distribution-level services, which is in harmony with the broader electricity market design that favours competition and price-based coordination. This DSO remains a neutral facilitator and isn't dictating who can or cannot consume. The market sorts out the most efficient response, consistent with how energy and ancillary services are handled at higher levels. Consumers with flexibility become active participants, which aligns with EU policy goals of empowering consumers and demand response. Local flex markets encourage TSO-DSO coordination and has been demonstrated in the GOPACS platform at lower complexity levels (Dronne, Roques & Saguan, 2021). This collaborative approach is considered a model for future power systems and is being written into network codes and guidelines. Therefore, adopting local flexibility markets would be seen as a progressive but system-aligned step, rather than a disruptive change.

Dynamic tariff adjustments also enjoys a High institutional fit. It leverages the existing role of the DSO as the party setting network tariffs (approved by the regulator) and stays close to the traditional tariffs-based mechanism to influence grid usage. There is no new market to establish or players to introduce as it continues the status quo in a more dynamic way. Moreover, dynamic tariffs do not require any intervention in customer equipment, which fits the Dutch values of consumer freedom. Each consumer remains free to respond to prices or not, and their supplier remains the billing interface. One could argue that dynamic tariffs shift some operational responsibility onto consumers/aggregators (to react to prices), but this is in line with the long-standing neoclassical economic principle that price signals (when designed solidly) drive efficient behaviour in markets. The Dutch ACM's focus on fair cost allocation indicates they support tariffs that better signal the cost of using the grid at peak times (ACM, 2024).
There is a need for coordination with suppliers so that the price signal reaches consumers effectively, but this is manageable as shown by dynamic electricity prices. Dynamic tariffs also don't conflict with any unbundling rules or market liberalisation principles, because the DSO is not engaging in energy trade or controlling assets.

Dynamic capacity tariffs exhibit a High institutional fit within the current Dutch electricity sector structure. This solution comfortably slots into the traditional roles of market actors: the DSO remains the key player by adjusting network tariffs (a function it already performs), and the ACM oversees the tariff design and approves any new structure to ensure it meets public interest criteria. There is no need to create a new market operator or give DSOs a fundamentally new role. This alignment is highlighted by the fact that many DSOs across Europe advocate for greater use of capacity charges to deal with peak loads.
The model also respects the liberalised market structure. Consumers, suppliers, and aggregators remain free to respond to price incentives, with competitive operations continuing largely unchanged. Retailers can integrate the tariff into contracts as with other network charges, and aggregators can adapt battery operations without role conflicts.

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7.7 Recommended solution

Evaluating the four solutions across all criteria, Local Flexibility Markets emerge as the most balanced and promising approach for congestion management in the near term. It achieved High effectiveness in reliably mitigating transformer overloads through direct procurement of flexibility, and scored strongly on fairness (with voluntary participation and compensation), regulatory alignment, efficiency, and institutional fit. This solution taps into market mechanisms that are consistent with Dutch and EU policy direction, and it allows the DSO to resolve congestion at least cost while respecting the liberalised market structure.
Crucially, it also creates opportunities for consumers and aggregators to earn revenues by offering flexibility, turning a problem into an economic opportunity. Given these advantages, a local flexibility market is recommended as the preferred solution among the four.
Table 5's scores highlight that while DLMP, dynamic tariffs and a Dynamic capacity tariff have their merits, the local flex market scores the most "High" ratings and no critical lows. Therefore, the local flexibility market approach is recommended as the preferred solution for congestion management with residential batteries. It is important to note that its implementation is accompanied by strong regulatory oversight and iterative improvements to address any operational issues that arise. This way, the solution can deliver on reliability goals while maintaining the trust and participation of all stakeholders in the electricity system.

Table 5: Evaluation results of four design solutions.

Criterion	DLMP	Local Flex Market	Dynamic Tariff adjustments	Dynamic capacity tariff
Effectiveness in congestion relief	Medium/High	High	Medium	Medium
Fairness & Consumer Acceptability	Medium	Medium/High	Medium	Medium
Regulatory Compatibility	Medium	Medium/High	Medium	Medium/high
Economic Efficiency & Revenue Impact	Medium/High	High	Medium	Medium
Implementation Feasibility (ICT/Data)	Low/Medium	Medium	Medium	Medium
Institutional Fit (roles & market structure)	Medium	High	High	High

8 Discussion of findings

The findings from Chapters 4, 5, 6 and 7 reveal an interplay between market forces, technological capabilities, and regulatory context. In this chapter we compare these findings, first with the stakeholder perspectives and then with the theoretical frameworks outlined Chapter 2. The sections provides a reflection on the proposed local flexibility market.

8.1 Stakeholder discussion

The proposed solution, local flexibility markets, has different implications for each stakeholder in the Dutch electricity system. However, the success of the solution depends on the involved stakeholders. Below I discuss how five key stakeholder groups are likely to view this solution, including their support, concerns, and the frictions or incentive alignments expected. This is done based on actual statements through personal communication, the researcher's knowledge of the participants (namely aggregator and consumer) and their general positions regarding innovations, market formation, and price signals.

8.1.1 DSOs

In an interview with the DSO they have noted that "the behaviour that's most beneficial for society should also be the most rewarding". This principle aligns with local flexibility markets, where actors are paid to shift loads. It does also align with the other explored options, but more by penalising negative influences instead of rewarding positives. In doing so, the grid benefits and the actors earn revenue, aligning private incentives with the public interest.

Despite this support, DSOs also have significant concerns and operational requirements for LFMs. Reliability and grid safety are paramount for DSOs, so they need certainty that flexibility will actually prevent overloads. In critical moments, a DSO cannot rely solely on voluntary market responses if an overload would cause outages. One interviewee stressed that during predicted congestion "you really must shut down" to stay within network limits, because "a price signal alone offers no guarantee" of sufficient response. This highlights a key point of friction: DSOs desire guaranteed outcomes whereas markets provide price signals that rely on participants' rational response. DSOs may therefore insist on a fallback mechanism (some form of direct control) or contract terms to ensure critical constraints are respected. Of course, if market is designed well, the price incentive should prove to be enough.
The payments may raise another concern, that of cost and fairness as the costs of payments to many resources will be socialised via grid tariffs.
Another DSO challenge is operational complexity and data requirements. Managing congestion locally requires high-granularity monitoring and forecasting at the neighbourhood or transformer level. In interviews, DSO representatives acknowledged that large parts of the low-voltage grid are still a "black box" with limited real-time metering. DSOs are working to improve their data capabilities. For instance, developing real-time load forecasts per substation and sharing this data. This improves transparency and will help participants understand why the local market has the determined price.

Overall, DSOs see local flexibility markets as promising for congestion management, but they seek assurances: accurate data, enforceable performance, cost control, and regulatory support for dynamic solutions. The prospects for implementation appear positive, as DSOs are already using platforms (like the GOPACS platform in the Netherlands) that let them procure flexibility regionally, yet on a higher market level.

8.1.2 Aggregators

Aggregators are generally expected very supportive of local flexibility markets as a solution. From an aggregator's perspective, a well-designed local flex market can resolve the conflict between maximising value in national markets and respecting local grid constraints. More importantly maybe, the local flex markets present aggregators (which are a profit driven entity) with an additional revenue stream. Without this market, aggregators face the risk of static DSO restrictions that simply forbid certain operations without compensation. The flex market lets them do what they're good at: leveraging their connected flexible assets to generate benefits based on market signals. It allows aggregators to continue operating flexibly, earning revenue from system services, while getting paid to help relieve local congestion when needed. If the right price signals are introduced, aggregators and their customers can be incentivised to adjust behaviour in ways that serve the grid's interest.

Aggregators also see challenges in the implementation, around information asymmetry and coordination with DSOs. Historically, aggregators have had visibility on where their flexible assets are and how they can operate them, but they have little insight into real-time local grid capacity or impending bottlenecks. Meanwhile, DSOs know where the grid is constrained but may not know exactly how much flexibility is sitting behind a particular transformer. This mismatch was described as a "paradox" in the interviews. The aggregator will insist that the flexibility market improves the transparency of congested areas.
Another concern for aggregators is market complexity and revenue uncertainty. Participating in an LFM could mean adding another layer of decision-making: now the aggregator must consider the price in the national imbalance or ancillary market and the price (or constraint) in the local market. There is a risk of conflicting signals and ff not properly harmonised, these multi-level market signals could increase operational complexity. Regulators will have to update frameworks so that aggregators aren't caught between conflicting obligations.

8.1.3 Regulators

The regulatory perspective on locational flexibility markets is nuanced: regulators are supportive of innovation that can address congestion cost-effectively, but are also wary of unintended consequences and are responsible for updating rules to fit new market models. Recent developments in Dutch energy policy illustrate this balance. In April 2024, ACM explicitly endorsed making grid use more flexible to alleviate congestion, unveiling a "package of measures against grid congestion" (ACM, 2024). Here they put measures in place to make flexible use of the electricity grid attractive; a clear regulatory signal that favours market based or tariff based flexibility. Regulators also adjusted connection procedures so that projects which "relieve the grid get priority" in grid connection queues. This means that batteries (albeit that this was focused on heavier than residential connections) jump ahead in the waiting list for new grid capacity. These shows alignment with local flexibility markets: rewarding flexibility and prioritising solutions that ease congestion. Despite this supportive stance, there are also concerns about fairness and consumer protection.

Regulators must consider how LFMs impact different groups of consumers and whether any new market might lead to exploitation or unequal treatment. For instance, if only a few savvy players/early battery adopters can participate in flexibility markets, they might reap rewards while others bear costs. This makes the ACM is mindful of the distributional effects of introducing congestion pricing in local markets. Another regulatory concern is market integrity and oversight. If local flexibility markets are established, ACM will have to regulate them setting rules for participation, preventing market power abuse, and ensuring transparency. The dena report on a German local flexibility market pointed out that incentive regulation, market design and grid fees must be reformed to allow for a efficient local flexibility market and prevent gaming (EPEX Spot, 2019). For the ACM, this means that they will have to ensure that any local market is not exploited by participants, driving up flexibility prices and thereby increasing grid costs for all.

8.1.4 Consumers and prosumers

The final group, consumers, can be divided into prosumers with batteries and ordinary consumers without significant flexibility.

For battery-owning prosumers, local flexibility markets are largely an attractive proposition. They have invested in assets like home energy storage or electric vehicles, and they seek to maximise the value of those assets. A local flexibility market provides an additional revenue stream: they can earn money by making their flexibility available to the DSO during local congestion events. This is on top of any savings they already get from using the battery for time shifting, or in response to passive imbalance signals. Monetising additional flexibility improves the return on their investment. Prosumers would prefer a smart market solution over being simply constrained with no compensation. In the absence of a local flexibility market, prosumers could be subject to battery usage restrictions by the DSO. This diminishes the potential return on their battery. For prosumers with batteries, a big-brother issue may arise. The interviews noted that the enforcement of any flexibility agreement is paramount. If one's asset is set to respond (through their aggregator) to a flexibility request by the DSO and something goes wrong the aggregator must be able to identify where the problem originated. This implies tracing a problem potentially to an individual user or device and can raise uncomfortable feelings if feel they could be blamed or penalised for the failed response. Clear participation rules about responsibility is therefore important.

For ordinary consumers without residential batteries, for Frank Energie this is around 90% of the customer base (Frank Energie, internal data), local flexibility markets remain a more abstract concept. But this is not necessarily a problem, as they do not interact with them much. These consumers primarily care about reliable supply and affordable bills. In principle, if local flexibility markets succeed, the whole system benefits from reduced congestion and deferred grid investments, which should translate to fewer blackouts and a more stable or slower-growing grid tariff. Consumers would support local flexibility markets as long as their bills are not increased by much. Given that grid expansions can be postponed with local flexibility markets, a positive stance is expected.

8.2 Theoretical framing

Having discussed the practical stakeholder viewpoints, a theoretical reflection on the proposed solution of local flexibility markets for dynamic congestion management is shared. I examine this approach through the lens of neoclassical economic theory, building on foundations from Chapter 2 and identify where real-world complexities (market failures and regulatory challenges) come into play. Also, the concept of regulatory overshooting is discussed.

8.2.1 Neoclassical theory the case of missing markets

Neoclassical economic theory suggests that if certain ideal conditions are met markets will lead to efficient outcomes (Pareto optimal allocation of resources) via the price mechanism. In a neoclassical world, there is no need for an intervention, since prices naturally reflect all costs, and individuals maximising their utility would simultaneously maximise social welfare.
However, the reality diverges from these assumptions, leading to challenges and the need for an intervention. Perfect information is absent, DSOs lack real-time data on local loads and insights in flexible assets. Likewise, aggregators miss information on local grid capacity. This gap prevents the calculation off reflective price signals. Rationality of actors is a reasonable assumption in this context. The evidence that aggregators and prosumers respond to whatever incentives they perceive is plentiful as they are profit seeking or cost minimising. So while actors are rational, they optimise on incomplete pricing that lead to a negative externality: a textbook example of a missing market.

Neoclassical theory states that internalising an externality allows a market to reach efficiency. Local flexibility markets can be interpreted as a way to internalise the externality of distribution congestion. By assigning a price to using the grid's scarce capacity market forces should arrive at the preferred equilibrium, aggregators would face the true costs of their actions. In theory, this brings the system closer to the neoclassical ideal. Each rational actor, upon seeing the price for causing (or relieving) congestion, will incorporate this into their decision making. Thus it can be argued that locational flexibility markets are a mechanism for fulfilling neoclassical predictions by incorporating a market where there was none. It aligns with the neoclassical principle of not abandoning the market once it fails but rather refining it.

This aligns with Ronald Coase's seminal argument (Coase, 1960) that, when property rights are clearly defined and transaction costs are low, parties can negotiate to resolve externalities without central regulation. In the context of congestion management, a local flexibility market (or any of the other options with some dynamic pricing) effectively defines a form of "usage right" for scarce grid capacity and sets a price for exceeding it. This creates the conditions for market participants to negotiate, through bids and responses, the most efficient allocation of the constrained resource. Of course, as Coase also emphasised, high transaction costs or poor information can prevent such bargains from reaching efficient outcomes, which is why institutional design and transparency remain critical in practice.

It should be noted that there are assumptions that are not satisfied. Local markets are more likely to have imperfect competition since there can only be a limited number of participants connected in a given area (both assets and aggregators). Scholars have cautioned for strategic behaviour that undermines the naïve neoclassical outcome. Secondly, the idea of no transaction costs. In reality, setting up and running a local flexibility market involves transaction costs: the infrastructure for communication, the time/effort for participants to engage, measurement and verification systems, legal contracts, etc. These are manageable but non zero. If transaction costs are too high relative to the congestion problem, a market solution might not be worth it. These realities mean that while the concept of local flexibility markets is rooted in neoclassical logic (using price signals to allocate a scarce resource efficiently), their practical design must contend with market imperfections.

8.2.2 Market failures and design

Given the deviations from ideal conditions, it becomes clear that market failure theory provides a more compelling initial explanation for why local flexibility markets are needed. Market failure theory, as an extension of neoclassical economics fuels the following discussion. The situation prior to local flexibility markets can be seen as a classic case of externality and public resource mismanagement. The distribution grid at peak times is essentially a common pool resource. When too many users draw heavily, congestion occurs: a "tragedy of the commons" where individual users acting in self-interest collectively overload the shared asset. As no price is attached to additional or heavy usage, the market fails to self-correct. Additionally, a coordination failure worsens the problem: DSOs couldn't fully predict when/where issues would happen due to lack of data on behind-the-meter assets responding to various signals, and aggregators didn't have information on grid stress to incorporate into their decisions.

Market failure theory argues that when externalities or missing markets exist, government intervention or collective action is required to improve outcomes. Initially, DSOs and regulators responded with blunt restrictions. This solved the immediate risk but creates inefficiencies. The more elegant solution is to correct the failure by internalizing the externality. This is where market design comes into play as a remedy for market failure. Instead of command-and-control regulation, create a market for the scarce resource where the externality gets a price. This allows for coordination between aggregators and DSOs

A second market failure has to do with public goods. Reliability of the grid has public good characteristics: using the local grid is non-rival up to the capacity limit and rival at or over the capacity limit. Without coordination, users have no incentive to individually protect this shared reliability beyond maybe social conscience. Market failure theory suggests mechanisms like regulation or collective schemes to manage such commons. A local flexibility market can be seen as creating a club good management tool: those who can relieve strain get rewarded, those who cause it effectively pay (either with a direct price, or by missing out on payments for relieving congestion).
Additionally, information asymmetry is addressed by the local flexibility market structure: it ensures a level of transparency. The DSO must announce where and when flexibility is needed, and the aggregator must reveal (through bids/offers) how much flexibility it can provide at what price. This information exchange is far more efficient than both parties operating in the dark and can be organised in a market platform.

Therefore, from a theoretical point of view, market failure theory not only explains why the unregulated scenario was problematic but also suggests the creation of a corrective measure to solve the market failure. In this research the local flexibility market is identified as best suited to solve the market failure.

8.2.3 Regulatory overshoot

A key concept that I introduced in this thesis is regulatory overshoot. In the context of this research, the static restrictions are viewed as a regulatory overshoot. Regulators were aiming to guarantee reliability under uncertainty. Given the poor visibility (no perfect information) and rising risk, they erred heavily on the side of caution. Because the measure was not finely targeted, it also prevents beneficial activities from residential batteries at times when this is not necessary. Because the DSOs don't have significant downside of the lost flexibility, whereas the political downside of outages is large the option to overshoot to avoid an 'under-shoot" is understandable. With improving data-insights the interviews with DSO experts stressed that with better forecasting, only 20% of winter days, instead of all winter days need action and only in specific problem areas, not entire regions. This reveals that this regulatory overshoot is a product of lacking technical capabilities and information sharing.
The concept of adaptive policy, introduced in Chapter 2 comes in as the opposite to overshoot. Regulatory overshoot is a kind of government failure, where the solution imposes new costs or inefficiencies. Adaptive regulation seeks to minimise that by continuously tuning the response to the actual state of the system. Local flexibility markets exemplify this approach. The approach also incorporates a feedback, if it is cheap to provide flexibility, congestion prices stay low. If few participants can or want to provide a response, the price rises making the market self-adjusting to some extent.

8.3 The impact of the chosen methodology

This final part of the discussion reflects on how the chosen hybrid between the Design Science research and systems engineering methodology influences the research outcomes. The structured, multi-phase design approach shaped both the strengths of the solution and its limitations. It also directed the solution space towards options that fit within existing structures rather than pursuing unconstrained innovation.

8.3.1 Strengths

The hybrid approach provided a structured, multi-phase process that grounded the solution in real-world needs. Early stakeholder engagement and regulatory analysis ensured the solution aligned with practical challenges, market realities, and existing Dutch/EU policies. By integrating technical, market, and policy perspectives, the method produced a balanced, implementable congestion management design rather than a purely theoretical concept.

8.3.2 Limitations

The approach also had constraints. No live pilot or iterative prototyping was conducted, leaving the framework untested in practice. Evaluation relied on qualitative reasoning and expert judgement rather than empirical data, introducing uncertainty about real-world performance. Similarly, the time constraints of a masters thesis allow for limited refinement in the many feedback cycles of a DSR and might leave some operational may remain hidden. Stakeholder input also may have biased priorities despite efforts to balance perspectives, conducting the research at an very dynamic aggregator shapes the research in a certain direction.

8.3.3 Influence on the solution space

The methodology steered the solution toward incremental innovations that fit current structures, prioritising regulatory compatibility and stakeholder acceptance. This favours concepts like local flexibility markets, that are evolutionary and institutionally aligned, while it filters out more radical ideas such as DLMP that require major structural changes. The outcome is pragmatic and implementable but bounded by today's market framework.

8.3.4 Robustness and future testing

Within scope of the research, the recommendation of local flexibility markets is robust: it scored highly across technical, economic, and regulatory criteria and addresses the defined problem without major flaws in concept. However, this robustness is fully theoretical, meaning that before large scale implementation it needs:

- Empirical validation through pilots to confirm congestion relief performance.
- Scalability tests to assess multi-aggregator dynamics.
- Integration of other assets beyond residential batteries.
- Operational prototyping to address IT, data-sharing, and real-time control.

Summarising, the method produced a context-aligned, decision-ready framework for Frank Energie, but real-world trials are essential to convert it from a strong theoretical proposal into a proven operational solution.

9 Conclusion

This research set out to determine how aggregators can minimise their revenue losses due to DSO-imposed trading restrictions through an alternative congestion management approach. The solution should balance the revenue preservation with mitigating congestion in the distribution grid. The research has demonstrated that the key to achieving both objectives lies in leveraging local flexibility markets as the cornerstone of the solution.

9.1 Main findings and answer to the research question

The thesis concludes that local flexibility markets offer a viable win-win mechanism for aggregators and DSOs to handle congestion. In the proposed dynamic congestion management framework, the aggregator uses data-driven forecasts (of demand, generation, and grid capacity, provided by the DSO) to anticipate congestion events and strategically deploy its battery assets. Instead of simply curtailing operations under DSO-imposed restrictions, the aggregator bids its flexible capacity into a local flexibility market or platform whenever the risk of congestion arises. In practice, this means the DSO can procure flexibility services from the aggregator's batteries to alleviate local grid constraints. The aggregator is compensated for their intervention, which offsets the revenue it would lose due to the imposed trading restrictions. The height of the compensation is determined by market forces and optimal if the market design is solid. This market-based transaction directly addresses the research question: the aggregator minimises its revenue loss by monetising its flexibility instead of being passively curtailed, and congestion is mitigated through the targeted activation of that flexibility. In essence, what was formerly a restriction becomes an opportunity. These findings align with the wider evidence that providing flexibility to system operators can be a successful additional revenue stream for aggregators and that the decentralised nature of aggregated batteries and demand response is well-suited to solving distribution-level congestion. The proven success of GOPACS at higher grid levels further demonstrates the theoretical potential of local flexibility markets. The success of GOPACS and updates to the grid code reflect the understanding that third-party flexibility is crucial for grid reliability. Aggregators can be important partners of DSOs for congestion management, and are willing to be with fair compensation.

The thesis findings carry significance in the context of the Dutch electricity system. The Dutch electricity system is currently grappling with severe grid congestion, especially at the distribution level, due to the rapid growth of renewable generation (e.g. solar PV) and the electrification of transport and heating. If left unaddressed, this congestion threatens to stall economic growth and derail climate goals. Traditionally, the solution to congestion is to reinforce and expand the grid; however, grid reinforcement is time-consuming and capital-intensive, and it struggles to keep up with the pace of demand for new connections. The dynamic congestion approach discussed in this thesis offers a more immediate and cost-effective tool to complement grid expansion. By harnessing residential batteries through local flexibility markets, DSOs can manage overloads in real time and defer or reduce the need for physical grid upgrades. By allowing aggregators to actively participate in congestion management network capacity can be used more efficiently. The approach also aligns with Dutch regulatory trends. The national regulator (ACM) and system operators have been moving toward market-based congestion management solutions, as seen with the GOPACS platform in the Netherlands.

9.2 Recommendations and future research

To fully realise the benefits of local flexibility markets, supportive policy and regulatory actions are needed. Key recommendations are the following:

- Formalise and expand local flexibility markets:

Regulators should establish clear frameworks that utilise market-based flexibility as a first option for congestion management rather than blindly resorting to curtailment. The European Electricity Directive already calls for incentives for DSOs to create such markets. In the Netherlands this means setting up a GOPACS-like platform for the LV-grid level. By embedding local flexibility markets into grid planning and operations, flexibility from residential batteries can be routinely used to solve congestion.

- Enable broad participation

Lower the barriers for aggregators to participate in these emerging local flexibility markets. For instance, the new Congestion Management Service Provider role requires aggregators to have a capacity >1 MW to participate. This prevents LV-level offering of flexibility to DSOs, while the potential of this flexibility is big. Additionally, by lowering the thresholds for participation, more competition and liquidity for local flexibility should be attracted.

- Improve data sharing and coordination

A data-driven approach requires better information exchange between DSOs and aggregators. Regulators and system operators should facilitate secure data sharing protocols so that aggregators can receive timely signals about local grid conditions. Armed with this data, aggregators can optimise their battery dispatch in advance, which increases the reliability of congestion management actions. Similarly, coordination between local and national markets should be enhanced: for example, flexibility that is not activated for a local DSO need could be allowed to participate in TSO-level balancing markets (value stacking), provided it does not create local problems.

The thesis provides valuable insights in local flexibility markets, but also needs further research to deepen and extend the findings.

- Scaling and market design

Future studies should examine the performance of local flexibility market mechanisms at larger scales and in various market design configurations. For example, research could simulate multiple aggregators competing in a local flexibility auction to understand price dynamics, or explore different auction formats. Current studies have shown that insufficient competition leads to gaming and inefficient outcomes. How these can be offset needs further investigation as well.

- Integration of diverse resources

The framework here focused on battery capacity, but aggregators manage a portfolio of resources, including EVs (with vehicle-to-grid capability), flexible industrial loads, and even smart thermostats. Future research could investigate how these heterogeneous resources can be integrated into a congestion management scheme. The different resources have different response characteristics. E.g. an EV might not always be available and thermostats have little flexibility during cold winters.

- Advanced data-driven control

Given that this thesis emphasises the importance of data in the approach, another avenue is to incorporate advanced forecasting techniques and real-time control algorithms. Further research might apply machine learning to improve congestion prediction accuracy at the feeder or transformer level, or develop adaptive control strategies for batteries that react to DSO signals in real time.

- Long-term impacts

Lastly, a valuable study to conduct is on the long-term impacts on the system. This includes assessing how much infrastructure investment can be deferred or avoided over a decade thanks to flexibility, as well as any unintended consequences. Socio-economic analysis could also be conducted on the role of aggregators in future energy markets. Such research provides policy makers with qualitative evidence to craft regulations on. GOPACS, being a similar system on higher grid levels can serve as a case study.

In conclusion, this thesis identifies local flexibility markets as the central pillar of a dynamic congestion management approach that benefits both aggregators and the electricity grid. By turning constraints into opportunities, aggregators like Frank Energie can not only safeguard their own revenues but also actively contribute to a more resilient and efficient Dutch power system. The recommendations and future research outlined above aim to support the continued development of this approach, ensuring that the Dutch electricity network can meet the challenges of the energy transition with agility and ingenuity in the short- to medium-term.

10 Personal learning points

With this thesis marking the end of my academic journey this final chapter presents my reflection of the process.

The process of completing this thesis was far from perfect, but it has been one of the most instructive experiences of my academic journey. I began the project with a clear plan, or perhaps more with a clear end goal. Around 60% into the process it became evident that the original approach was not feasible, data that I needed for my thought of methods was not available. That was a turning point. I made the necessary decision, together with my supervisors, to change direction. It meant rethinking the methodology, putting in extra hours, and working under time pressure, but it allowed me to deliver a result that was both coherent and relevant.

Most of this could have been prevented however, if I had reached out to my supervisors sooner than I now did (only at the green light meeting). I draw from this the lesson that I should ask for help sooner than I like to do. I also learned a lesson about preparation. Looking back, I could have spent more time upfront stress-testing the feasibility of my original plan. Of course, you can't predict every challenge, but a more critical early review might have saved me from such a late pivot. It's something I'll carry into future projects: think more before doing.

At the same time, I (re)discovered strengths. I'm resilient when things get tough, I can keep moving forward when circumstances change suddenly, and I'm able to draw on different skill sets to solve problems creatively. I'm also able to perform well under (time) pressure, which helps a lot when deadlines are approaching. On the other hand though, I tend to postpone bigger tasks until they really need to be finished at some times creating unnecessary pressure for myself. I noticed in the later stages that I help myself by dividing bigger task into smaller task so that I can tick one of sooner rather than later.

One of the most rewarding parts of this project was seeing how my bachelor's and master's studies came together. My background in Innovation Management and Natural Sciences from Utrecht University equipped me with skills in stakeholder engagement, organisational analysis, and bridging technical and societal perspectives. My master's in Complex Systems Engineering and Management at TU Delft added the technical, policy, and systems-thinking tools needed to carry out the research. Bringing these disciplines together not only strengthened the quality of my work but also confirmed that I've chosen the right academic path. It is one that sets me up well for an industry that is extremely relevant right now, but above all one that I find particularly interesting.

In the end, the process didn't go as I imagined (which funnily is something I imagined), but it left me with sharper skills, better self-awareness, and more confidence in my ability to adapt and persevere in complex, high-pressure environments.

10.1 AI statement

Generative AI has been used by me in writing this thesis. I have mostly used ChatGPT, model 4 and 4-o. The use of AI has been primarily to enhance the academic style of my personal writing. It has also helped me in structuring sentences, or concepts that I could not get conveyed clearly by myself. I claim full responsibility for the written text in this thesis.

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Appendices

Appendix A: Structured literature review

The tables below show the search queries that have been used in the literature review on state-of-the-art congestion management and the results they have yielded.

Table 6: Search queries used in the review.

Keywords used in Scopus	Number of hits, published 2020 or later	Inaccessible articles	Excluded articles based on Title, Abs & Key	Selection
''Grid congestion" AND ("Netherlands" OR "Dutch")	N = 16	N = 5	N = 6	N = 4
("Dutch" OR "Netherlands") AND ''energy market" AND "batteries"	N = 4	N/A	N = 3	N = 1
(''Energy market" OR "electricity market" OR "electricity grid") AND "aggregator" AND "grid congestion"	N = 6	N/A	N = 2	N = 4
("Home battery OR "RESS" OR "residential energy storage system") AND "grid congestion"	N = 3	N/A	N = 3	N = 0

Table 7: Selected literature review from search.

Article	Title	Take away
Brinkel et al., 2022	Grid congestion mitigation in the era of shared electric vehicles.	Shared EVs provide increased congestion mitigation possibilities over privately owned EVs at lower costs through higher predictability.
Yu et al., 2022	Comparative Impact of Three Practical Electric Vehicle Charging Scheduling Schemes on Low Voltage Distribution Grids.	EV charging scheduling schemes enable better grid performance than uncontrolled charging.

Brinkel et al., 2023	Dynamic Grid Tariffs for Electric Vehicle Charging: Results from a Real-World Experiment.	Dynamic grid tariffs can reduce transformer congestion by 21%. Further research on other values of DSOs should be done.
Van den Boom, 2023	Experimenting with co-ownership of energy storage facilities – A case study of the Netherlands.	Role of grid managers needs to change. Use exemptions in EU directives to experiment more.
Argiolas et al., 2022	Optimal Battery Energy Storage Dispatch in Energy and Frequency Regulation Markets While Peak Shaving and EV Fast Charging Station.	BESS combined with EV charging and PV-installation both diminishes connection capacity requirements and peak loads.
Brinkel et al., 2021	Avoiding Low-Voltage Grid Congestion using Smart Charging of Electric Vehicles based on Day-Ahead Probabilistic Photovoltaic Forecasts.	Aggregators can mitigate grid congestion if they consider grid constraints in their optimisation process.
Almeida et al., 2021	Coordination strategies in distribution network considering multiple aggregators and high penetration of electric vehicles.	DLMPs are effective for congestion management but they negatively impact aggregators profits.
Kara et al., 2021	Stochastic local flexibility market design, bidding, and dispatch for distribution grid operations.	Local flexibility markets mitigate grid congestion and defer expensive grid investments.
Khaksari et al., 2024	Electricity market equilibria analysis on the value of demand-side flexibility portfolios' mix and the strategic demand aggregators' market power.	Demand aggregators (DA) are crucial in congestion management by leveraging demand side flexibility. Increased competition is beneficial for costs and lowers market manipulation.

Appendix B: Data types

Table 8 shows all types of data which are collected and processed in writing this thesis. The table was created for the data management plan which had to be submitted to the Human Research Ethics Committee. This was necessary in to get approval to work with human data subjects, e.g. for interviews.

Table 8: Different types of data and their properties.

Type of data	File formats	Data source	Purpose in research	Stored in location	Accessible by
Scientific literature	.pdf	Scientific databases (e.g. Scopus)	Theoretical understanding of problem	TU Delft OneDrive	Researcher
Grey literature	.pdf	Government & policy sources	Market/real world understanding of	TU Delft OneDrive	Researcher

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			problem and regulations		
Name + e-mail interviewees	.docx, .text	Company network & interviewee	Contacting interviewees	TU Delft OneDrive	Researcher
Interview records and transcripts	.Mp4 or .M4a	Interviewee	Gathering expert insights	TU Delft OneDrive	Researcher and supervisor
Anonymous summary of transcript	.docx	Transcripts	Allow interviewee to revise their contributions	TU Delft OneDrive	Researcher and interviewee
Company knowledge/technological capabilities	.docx, .text or .pdf	Company database or personal communication	Match theory with application	Frank Energie OneDrive	Researcher and company supervisor

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Appendix C: Expert interview summaries

Interview 1

1. **Grid operators, politicians or research institutes are all calling grid congestion a major problem for the energy transition, but how concrete can we actually identify the problem?**

The main way we used to detect this in the past was simply that people would phone the utility when their lights started flickering. Nationally, I believe only about 40–50 percent of transformer stations are metered. Those measurements show the current grid loading, and if we add more heat pumps or electric vehicles, the grid operator can of course make solid forecasts of what will happen. In the province Zeeland, for example, emergency generators already had been connected to the grid because demand was forecasted to be too high during Christmas. Afterwards they proved necessary. Those are serious problems.
Measuring congestion itself is not that complicated; stating afterwards that: "there was congestion here" is not the trick. The crux is in actively predicting it. Saying today that congestion will arise tomorrow is very complex. It becomes even more difficult when you introduce all kinds of short-term incentives such as passive imbalance, aFFR and intraday markets, which are not known in advance. Day-ahead forecasts are available, so you can, for instance, decide when EVs will charge and the grid operator can still do some shifting. But for unexpected incentives you need to build in a safety net on top of the margin you would normally allow.

What causes this to be so problematic?

We observe that all those market parties are constantly ramping up and down in response to signals, which causes a lot of fluctuation. What the grid operator mainly lacks is insight into the number of assets (and their capacity) that will respond to imbalance signals or other short-term incentives. What would help enormously is if grid measurements could be greatly improved and if the day-ahead forecasts matched reality more closely. Based on our estimates, only about 20 percent of winter days actually run a real risk of congestion. If we could forecast those days much more accurately, we could, for instance, take action only on that 20 percent of winter days instead of on every winter day. In addition, a grid operator does not have a clear picture of how many controllable technologies are installed in a neighbourhood, nor which of them will actually respond.
A grid operator does not want to approve new connections unless it is certain that power in the neighbourhood will not fail. At present, reliability is still close to 100 percent, and the main cause of power outages is a cable accidentally being dug up.

2. **How much can be saved in investment if we better spread the growing power demand across the grid?**

The IBO has calculated that €195 billion needs to be invested towards 2040. If we do that with smart measures, we can save around €30 billion on that.
That is absolutely worthwhile, but at what cost? Because steering home batteries to passive imbalance also just has real value. It keeps the system afloat, and prevents us from having to

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balance with more expensive and polluting gas plants. There is just current value in that flex, there has to be a good trade-off there.

Do you mean the trade-off with imbalance steering versus remaining congestion-neutral?

Yes indeed.

Does the passive imbalance market not get saturated if all of us start reacting to the imbalance signal with our batteries, EVs, heat pumps, and air cons?

Yes, when you're talking about the passive imbalance this is correct. That market is not that big. But there are also quite some other short-term market signals. The intra day market for example, there a party like Eneco who has loads of home batteries under their control can manage their portfolio without getting on the passive imbalance. So, when the problem of the passive imbalance is resolved the problem will not be completely solved. Furthermore do residential batteries compete with industrial sized battery storage systems for the most appealing business case.

3. **Is it desirable that residential batteries act on the (passive) imbalance?**

It is difficult to take a clear position here. I'm not in favour of it, partly because it's very difficult to reach clear agreements on the matter. Residential batteries are located behind the meter, which makes it much more complex to take a position on them. This causes the ACM (Dutch regulatory authority for energy markets), to be very cautious in their regulation. Because the meter cannot prove which part of the consumption or feed-in comes from the battery. Therefore, alternative transport rights, such as those that apply to large-scale batteries, are not possible.
We have a free market, so residential batteries are allowed to connect and act on the market. The idea of passive imbalance is that you take a position which deviates from the original position, whether this is with a residential battery, EV or washing machine, is not relevant nor is it traceable.

4. **What can DSOs currently put in place (reasonably quickly) so that congestion is resolved in a similar way to the imbalance that TenneT manages?**

Our recommendation is that the current tailor-made agreements are far too broad. We need to avoid imposing restrictions at times when they are not actually necessary. Our proposal is therefore to set any restrictions at the MSR (medium-voltage substation) level. That targets a much more specific area than, say, the whole of Utrecht. Only those MSRs for which the forecast indicates a risk of congestion would be subject to a restriction. In other words, you focus on the problem days and the problem MSRs, which lets you eliminate a large share of unnecessary restrictions, perhaps limiting action to only 10 percent of days and one-third of the MSRs.

On those occasions you do have to say: “You really must shut down,” because the grid operator needs absolute certainty that the network will stay within its limits; a price signal alone offers no guarantee. Compensation from the grid operator is possible, but it must be under a contract that leaves the other party no choice in the matter.
If you want to make this even more granular, you would need far more data. To tackle only the congestion hotspots, you would have to be able to measure, forecast, and communicate at the individual-MSR level—something that is still a step too far at the moment. Enforcement is also essential: if something goes wrong, you must be able to identify where the problem originated and with whom you had an agreement.

5. **A variable rate for waiving action seems undesirable, the grid operator does not know where it stands and these are theoretically infinite. So is a fixed rate, say a euro a time, feasible?**

Yes, you have to agree to that in a contract. You now see that in congestion management, capacity limitation contracts are being concluded. These often include a capacity fee, meaning you simply agree: “OK, I’m participating with a battery, so I receive predetermined amount X.

It is questionable whether this is manageable, owners of batteries receive a reimbursement which drives up the overall grid costs. Everyone pays for that.

Suppose you’re not allowed to react with your battery, but a model simulation which runs in parallel tells you what you would have earned otherwise. Is it then realistic to expect the DSO to compensate you for the lost revenue?

So I actually find this very difficult, because after a while a company like Frank Energie could have so many batteries. In theory, maybe 100,000 batteries could all claim they were entitled to respond to the imbalance. If that many batteries are reacting to the imbalance, then you could never have earned the same amount as a single battery in the model.
Another problem is that these costs would end up being passed on to the entire grid, meaning everyone’s costs would rise.
So from a market perspective, it makes sense to say, "Hey, I could have earned this money," but for the grid operator it’s really complex to figure out how to deal with that. I haven’t yet figured out what the best solution is here. Even just proving that a battery would have responded is already very complex.

6. **Just how often do congestion and passive imbalance happen at the same moment and contradict each other?**

We see something like 200 hours a year. But the risk is much higher. Suppose a transformer is loaded very high 10% of the time, then you have a problem when the imbalance moves in the wrong direction. If you impose restrictions when the load goes towards 95%, you don't know in advance what the imbalance is going to do, so you have to restrict more and more widely than was necessary afterwards. So it may well be that of the 20 days in which you have to restrict, only on 5 or 0 days congestion actually occurs.

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Interview 2

1. **How accurate can DSOs map congestion/the congestion problem?**

It all starts with readings and estimates: what is the current load, what reinforcements are coming, and how is demand expected to develop? The higher up in the grid, the better this is all in place. But in the low-voltage grid and at the medium-voltage transformer substations, we're still blind across large parts of the grid. That's steadily improving, but there's still a lot to gain.
At the moment were estimating what the load will be on a MSR, but this is not done with day with day profiles. We think it will be loaded above X per cent in Y amount of hours this year. Things like daily temperature and weather reports are not currently factored into this. So no, it is not very accurate.
The MSRs, where 10kV is transformed to 400V, are not yet metered in many cases. This is changing very quickly. In total, I think a few thousand of the total of around 40,000 transformer houses which Liander has, is metered. In the Netherlands, I think there are about 120,000. Thousands are fitted with measuring equipment every year. This is a rough estimate.

Why is an overload of a MSR such a problem?

A short, high load is manageable, but it should not last too long. As an overload lasts longer, the temperature in the MSR keeps on rising which could lead to parts in the MSR to fail. Of course, thermal buffers are put in place, yet long lasting overload could break certain components.
We make forecasts on this matter, that is good to know. Additionally, for a number of MSRs we have actual readings. We also have a mathematical model that tries to estimate which stations will exceed a certain load in the near future. This is based on number of houses, year of construction, solar panels, charging stations, etc.

2. **At the point when you have trained such a forecast model and compared and validated it through measurements, is the goal to notify market participants at short notice, say day-ahead via signals?**

Yes ideally you do. Ideally, you want to foresee overload situations as shortly in advance as possible so you can respond to them. Right now, for large consumers, this is generally organised on a day-ahead basis. If there is too much demand, the grid operator then knows that flexibility needs to be procured. That can be done through capacity limitation contracts or via a platform like GOPACS.
If you do this day-ahead, it may still be unnecessary. You want to be able to deploy flexibility to prevent overloading, but you don't want to deploy it unnecessarily. After all, that just costs society money.

3. **Is it realistic that a location-specific signal for congestion is created similar to how TenneT announces their imbalance signal?**

When Tennet calls upon flexible power, it would be ideal if this contains a regional specification: "There is a capacity problem nationwide, but based on real-time load, we would like to see the solution to this imbalance come from this area." But this is something you can

better ask TenneT, as they manage the imbalance markets. As you mention, conflicting interest can arise here. We would like to see that in all neighbourhoods where the expected load remains low, say below 80%, we do not have to impose restrictions. The time window can then be fixed, but there is a specification of location. That already makes a difference, and reduces the impact on the business case for batteries.
As DSOs we are for the usage of our grids. If there is room to act on imbalance or any other signal, by all means do so. But, we also have to ensure that this stays within the operational boundaries of the system. Ideally, when responding to imbalance, the behaviour that's most beneficial for society should also be the most rewarding. A basic economic principle, but an important one.

4. **What is your view on providing compensation for the time slots?**

The DSOs approach now is to not do that. This wriggles into how the tariff model for small consumers (kleinverbruik [KV]) is currently set up. As KV, you simply pay a fixed fee each year, regardless of what your usage is. You can do what you like with your connection, but if everyone uses theirs fully at the same time the grid fails. (Gives example calculation). I think that changing the KV tariff-model is very important considering the growing load on the grid. This is not limited to batteries, heat pumps, EVs and solar panels.

Are there opportunities for a discount on your grid fee if you demonstrate you battery is congestion-neutral or even remedial?

In the sprint team we're mostly discussing congestion neutral deployment, but when you're actively mitigating I feel that compensation should be on the table. In the same way as it is for wholesale consumers. There you do have to be careful that there is a bit of gaming lurking. For example, if someone has both a battery and solar panels. This can be a tricky puzzle.
For a DSO it would be ideal if we could say: "In this area X is the maximum capacity, and you can figure out how to use this." We can then appoint a market party who regulates power flow.

5. **What are restricting reasons which prevent aggregators from acting as a CSP?**

I read that after you mentioned it, I was not quite aware. I had actually suspected that an aggregator was a bit the old term for a CSP, but apparently it is not. On GOPACS you can participate as a wholesale consumer with your own CBC contract, or as a CSP. But a pool with multiple small participants is not possible. I think that registering this is still too complex. You need to have a very accurate picture of which flex assets are connected to which MSR to solve this. You can participate as a CSP from upwards of 100 kW of contracted transmission capacity, a KV connection does not have contracted transmission capacity.
Of course, we need to move to a more dynamic design of the proposed restrictions.
So we delved a bit in the available numbers, for how many MSRs the time windows should apply and the numbers seem to be okay. It is not about 90% of the MSRs. That is a big win. If we can refine the number with the influence of weather effects or the width or height of the restricted windows that would be big steps. And it all starts with obtaining more data insights.

Interview 3

1. **How does TenneT organise congestion management?**

There are two ways we handle this at TenneT. The first if by means of CBC's, capacity restricting contracts, here we can conclude up to a day in advance with a party when we expect overload to arise and thus ask them to shift or reduce demand. This is on a day-ahead market basis. The second is a redispatch product where we have to balance the grid once the electricity has been sold. Here one party has to up-regulate and the other has to down-regulate, to ensure that the total load in the system is the same, just spread out in a different way. This is done through the GOPACS platform to prevent a congestion solution in one grid from causing congestion on another grid.
In the past, these CBC products where mostly used during planned construction works, now we do this more based on forecasts.
Solar power is the biggest problem here. For a lot of consumers this remains uncontrollable power. Neither is there a financial incentive for most producers (households, on low-voltage [LV]) to procure their production. Hence we expect this to be the biggest cause of congestion in the near future.

2. **The LV-grid is connected tot he high-voltage (HV) grid, does this cause congestion in the two to coincide?**

Yes, it does. I don't have insights in the grids of the DSO, but basically congestion flows through the connected grids to each other. So in the case of solar PV on houses it comes to the TSO from the DSO grids.

Does this also happen the other way around? Or is TenneT better in forecasting their expected loads so it doesn't happen that much?

We're getting better at this. Due to the fact that we work together better on a platform like GOPACS. But we cannot yet rule out that something happening in our grid, causes congestion in the grids of the DSOs. We are cooperating more and more so it is becoming less and less. You also see that when a market party buys power on the HV-grid, then sells it in the LV-grid and this then causes congestion there is not much either of us can do about it. Other than calling upon a redispatch product.
Smaller wind farms, usually connected to 110 or 150 kV coupling stations cause local congestion regularly. So we are exploring how we can connect larger parties to these stations/wind farms that can increase their demand if we request this. With TenneT we do this on higher grid levels with larger/heavier consumers. But this could similarly be done on MSRs with residential batteries.

3. **Earlier we discussed forecasting of loads, how precise are these forecasts?**
    a. **Does it happen that a re-dispatch product is activated when it later turned out to be unnecessary?**

Actually, the forecasts are quite good, and getting more and more accurate. Previously we did this with stochastic models, that was less accurate. Now we also include much more historical data and weather input. As a result, we can often say with 80-90% certainty where congestion

will be. But whether we also act unnecessarily I can't really say, because we resolve the situation beforehand. Saying for certain whether it had really taken place is thus not really possible.
This accuracy is connected to the metering in our grid. We get an update every two minutes, this will soon improve to 30 seconds in some locations. So we have pretty good insights in what is happening. On mid-voltage (MV) level this is quite similar, especially the LV-grids are a big black box. If they're metered at all, it is often still on a quarter-hourly basis.

4. **Is there a possibility to send the imbalance signal which TenneT provides location-specific? Where, based on known or impending congestion problems, you add a notion that you would rather not have the response for imbalance come from location X.**

Yes, we don't know where the imbalance is coming from. We measure this in accordance with EU law, over the entire bidding zone. Thus we don't see where there is too much or too little supply, at the same time we do know where there is congestion so where ideally we do not want the response to come from. But we're not allowed to do something with this information as TSO. As TSO we have to give every party the freedom to access and participate in the market, also on passive imbalance. So, are we able to? Yes. Will it happen? No. So if you are somewhere in a congestion area and you respond to the imbalance incentive, we as TSO just have to call out a re-dispatch product.
If the regulations that deal with this are changed, then organising this is not a problem, that is not the obstacle. And it is good to remember that if we don't have super accurate insights into the DSO grid that these things become very complicated. If TenneT has congestion in (for example) Rotterdam, it does not mean that every Stedin district in Rotterdam also has congestion.

5. **What is needed to improve the insights at the DSO level?**

That comes down to the metering. They will have mathematical models which they compute. But once you obtain real data it just gives a much better insight.

Do you work together to achieve this?
Yes, this is the GOPACS platform again, those calculations are made there. Because ofificially we're not allowed to look into each other's grids. They make a general national calculation, this adjustment in X causes congestion in Y and is therefore rejected. GOPACS is some independent organisation, although the seven participants are the TSO and six DSOs, where these calculations come together. I didn't come up with it either, it is all regulation again.

Interview 4

This interview was conducted with two people, which are denoted as 'A' and 'B'.

1. **How accurate can Stedin currently map congestion issues? In the sense that you can pinpoint per neighbourhood/transformer station where and when problems arise.**

B: At the moment, a rough estimate is that we have metered 30% of our MSRs. So at 30%, we know precisely what is happening. At the same time, we are increasing the amount of installed meters, because we are also familiar with the issues at hand. We also need the information to know where and how to expand. Anything that is not metered, though, you can use clever tricks to sweep the information together. We have calculation models for the grid, which have an accuracy of about 95%. We do this with aggregation of smart meter data.

To aggregate smart meter data you need to precisely know which meter is connected to which MSR, is there any certainty about that?

B: We know this for all stations. Implementing the forecasts for all MSRs we are still working on now, in some neighbourhoods it has already been done quite a bit. But not 100% yet, we are still working on this and it should be fully realised soon.

A: Here, you also see a contrast regarding whether you actually need to meter every station to gain insight into the forecasted/real load of a station. Because the forecasts are accurate enough that, with smart aggregation methods, you can get quite far.

A: As soon as you start reacting to unpredictable passive imbalance (or other signals), that accuracy goes out the window.

2. **Can you already distinguish between locations in this issue?**

A: What is the big challenge here is the registration of high-load technologies, such as a heat pump electric charging station or air conditioners. Offtake is not registered anyway. For feed-in, though, solar panels are reasonably registered. For batteries, this is also required, but not enforced.

A: Currently we have smart algorithms that can use smart meter data to detect what kind of assets are present at a connection. That is reasonably accurate, however to do that for the entire service area is another matter.

B: To get the use-case for using this data approved did take 2 years. So we can already do quite a lot, but often something is not yet allowed by regulation. Whereas we do want a lot.

A: Fortunately, that approval is now there as B says, and so we can enter the phase of expanding, scaling up and verifying this. However, at the moment, this still makes it very difficult to restrict a location specifically. Purely due to the accessibility of data and what data we are allowed to use. We can thus say too little about which assets are in which district with which supplier and what behaviour they exhibit.

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What about the rules for metering imbalance? TenneT says it can but that they are not allowed by the EU grid code.

A: We get exactly this response from Tennet. 'The grid code and European legislation gives no room for this." But that is really a question of interpretation of rules more than how they are literally written. When we read those rules we interpret them from: yes, well, that it seems that those rules do provide that possibility. TenneT is of course incredibly cautious about intervening in market forces. That is quite understandable, because intervening goes against the principles of a free market.

A: If you were to do this location and time-specific based on an actual profile, that there are restrictions only when it is really necessary, then you are solving it as efficiently as possible. You give all the space to the market, and only when it is not there do you intervene. This way of constraining is also what we are aiming for.

3. **Do you make specific projections for each MSR as to what the load on that MSR will be?**

B: You can interpret this in two ways. On the one hand, it is done anyway for all our assets, so we know where we can and cannot connect more. But that is not always real-time. And what we are working on now is developing a real-time forecast, no metering, per MSR for flex assets. Currently this is still a pilot form, for something like 10 MSRs but that will be expanded in time. For Stedin, that means to 22,000 MSRs. That will take some time, but it is being actively worked on by all grid managers together. Via the same API.

A: And the idea behind that would be that, as a market party, when this is rolled out, you can retrieve the load forecast of an MSR. Then you have the same data as a grid operator and so you can see for your customers which locations are and are not going to be overloaded. This provides some insight into why we call certain flex bids.

And those restrictions, you want to call them off based on a predicted load of X per cent?

B: That policy is still being developed, but 80% load is often the amount adhered to. This is because in an MSR, from 80% load, certain components get damaged if this is held for a long time. 100% can be held for a few minutes and at 110%, it is done almost immediately.

A: And then we are talking about quarter-hour load. Probably that load means you had 120% load for a few minutes and 70% for the rest of the time. When you are talking about an LS transformer I believe they should be able to handle 140% for a minute, when this becomes 150% it only pulls that for a few seconds. This is also why simultaneous control of flex-assets is such a problem. You don't necessarily see this reflected in your quarter-hour profile, but when that's all on the same phase, your short-circuit fuses are suddenly used as overload fuses.

4. **As a DSO, what is your opinion towards home batteries?**

B: That is quite the paradox. If you look at how batteries have been deployed in the recent period, they exacerbate congestion. We do understand that commercial parties deploy them that way, but they exacerbate congestion. That has been calculated many times and I don't think is something that is in dispute. At the same time, of course, from a flex point of view for the DSO, we see that there are certain opportunities for peak shaving. Then batteries are very desirable, but you have to control them in certain ways. For example, by accommodating the generation peak of solar panels in the summer months.

A: Yes I think B puts that really super well. Home batteries can be incredibly helpful, but it does depend on the steering. The potential is there, but the certainty is unfortunately not there yet.

5. **How do you view the agreements that are now being made in the sprint team?**

B: To be honest, I agree with you that these are quite coarse. However, we need to build in a piece of safety for the grids. Our concern is that people can use their oven in the evening without being affected by imbalance trading. If we have the possibility to send a dynamic signal, which we are working on, we would of course prefer to do that. But our starting point remains that security of supply is most important.

Appendix D: Informed consent form

You are being invited to participate in a research study titled: *Enabling aggregators to deploy battery capacity for congestion management: Creating a framework* . This study is being done by Stijn Walsh from the TU Delft during an master thesis internship at Frank Energie, a Dutch energy supplier. The master programme is Complex Systems Engineering and management

The purpose of this research study is to create and test a framework in which aggregators can deploy the flexibility capacity in their portfolio on the congestion markets in the Netherlands. The purpose of this interview is to gain additional knowledge and explore your point of view on congestion management, home batteries and aggregators and will take approximately 45 minutes to complete. The data will be used for identifying barriers, opportunities, functional and non-functional requirements which are needed for aggregators in congestion management. We will be asking you to give your opinion on the state of the congestion market and it's management.

As with any online activity the risk of a breach is always possible. To the best of our ability your answers in this study will remain confidential. We will minimize any risks by storing all data, being personal information, name, function/education and e-mail address, recordings, transcripts and summaries of transcripts on the TU Delft OneDrive. This data is accessible by myself, my two research supervisors from TU Delft, prof.dr.ir. Laurens de Vries and dr. Aad Correljé. To ensure confidentiality, an anonymised summary of the interview will be provided to the interviewee in which he/she is given the opportunity to adjust the summary and communicate with the researcher which data can and cannot be used. Once the interviewee is satisfied with the summary, its contents can be used and published in the research output. Additionally, a copy of the transcript summary will be added to the appendix of the thesis, where any party who accesses the published thesis can view it. The full thesis, including appendix will be published on the TU Delft Repository, which is a public database. Once the researcher has graduated all personal information, transcript and recording will be deleted within one month.

Your participation in this study is entirely voluntary and **you can withdraw at any time**. You are free to omit any questions, or after answering questions call for the answer not to be used in the research output.

Corresponding researcher: Stijn Walsh

Responsible researcher: Laurens de Vries ________________

Please tick the appropriate boxes	YES	NO
I agree that my responses, views or other input can be used in the research output in an anonymised way.*		

*insert X in correct cell

Date

.... maart 2025