An Coimisiún um Rialáil Fóntais

Commission for Regulation of Utilities

Demand Flexibility Forecasting Report 2026

NEDS Action 0.3

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CRU Strategic Plan 2025-27

The CRU's vision, purpose, and values are set out in the graphic below. This is taken from the Strategic Plan 2025-27[1], which underpins the CRU's role in regulating Ireland's evolving energy and water sectors, and ensures that essential services are delivered efficiently, safely, and in line with national policy objectives.

[1] https://www.cru.ie/about-us/news/strategic-plan-2025/

Executive summary

Since the publication of the National Energy Demand Strategy (NEDS) Decision (CRU202467), the Commission for Regulation of Utilities (CRU) has been responsible for tracking the progress of the NEDS implementation as required by NEDS Action 0.3. This report addresses the demand-side flexibility aspect of Action 0.3 and forecasts the demand-side flexibility in Ireland, while action progress reporting and the impact on carbon emissions are covered by the NEDS Annual Update report. Forecasts presented in this report provide directional estimates for demand-side flexibility rather than definitive quantification of future demand-side flexibility and should not be treated or interpreted as targets. The flexibility volumes presented in this report relate solely to demand-side flexibility resources. They do not represent total system flexibility needs, nor do they capture all flexibility resources that may be available to the electricity system.

The NEDS Implementation Group, comprising of representatives from DCEE, DETE, EirGrid, GNI, ESBN, IDA, SEAI and ZEVI, have been consulted with throughout the development of this report. Members reviewed draft versions, participated in discussions, and were briefed on the report's findings. The CRU also engaged with the group to inform the scenario analysis, which is reflected in the report. This report has been prepared with support from Baringa Partners.

The objective of this report is to provide an update on the methodology and the resultant forecasts of demand-side flexibility covering the period from 2024 out to 2035 across three categories of demand-side flexibility sources: residential, commercial, and utility-scale. These forecasts are intended to reflect the latest developments, market progress, and updated assumptions reflecting realistic delivery timelines and project pipelines. This marks a shift from the initial 2024 baseline ambition set out in the NEDS Decision to the practical strategy delivery and implementation, informed by the completion of NEDS actions and insights from members of the NEDS Implementation Group.

The forecasts also reflect uncertainty around the future impact of policy, wider economic conditions, and progress in the delivery of industry programmes. Three scenarios are:

- **Expected Delivery:** Central scenario representing the best estimate of likely demand-side flexibility growth based on current evidence, assuming the existing policies and progress delivered as planned, and uptake and participation in flexibility are following a gradual growth trend.
- **Delayed Delivery:** Lower uncertainty interval assuming a delay in the delivery of existing policies and progress, persistent and substantial barriers to uptake and participation in demand-side flexibility remain unresolved.

- **Enhanced Growth:** Upper uncertainty interval assuming a high level of ambition, concentrated effort and coordination across the government, regulator and system operators (SOs). Assumes additional measures, over-performance of the existing measures, and accelerated participation enhance further growth in demand-side flexibility.

Overall, demand-side flexibility in Ireland is expected to grow steadily and significantly over the coming decade. Under the assumptions in the central scenario ("Expected Delivery"), demand-side flexibility is projected to approximately double by 2030**,** reflecting progress to date, with further growth through the early 2030s. Under the "Enhanced Growth" scenario, the proportion of demand-side flexibility is expected to exceed 20% of system demand[2] by 2033, enabled by higher participation rates and the scale of residential demand-side flexibility, as well as more successful procurement outcomes by SOs and efforts to remove barriers to demand-side participation in flexibility markets. Figure 1 shows these forecasts for the demand turn-down[3] flexibility across the three scenarios.

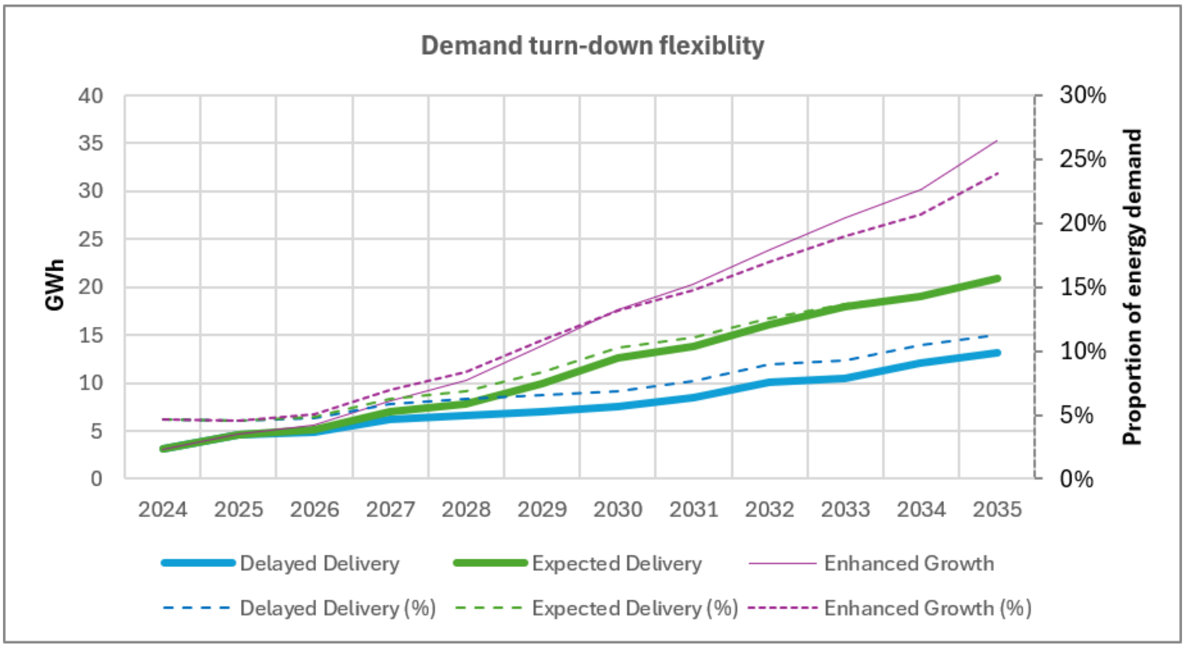

Figure 1: Forecasted demand-side turn-down flexibility for three scenarios in GWh and as % of Total Energy Requirement estimated by EirGrid.

In the near term, as a result of the expected impact of NEDS and implementation progress to date, flexibility procurement by SOs is a major driver of flexibility growth up to 2030-2032. Focus on the development of the demand flexibility products, by ESB Networks' (ESBNs') procurement followed

[2] Flexibility proportion is calculated as average daily volume of demand-side flexibility divided by estimated daily energy requirement. Detailed explanation is provided in the Methodology Section.
[3] Forecasts for Demand turn-up are also included in the report. For simplicity only Demand turn-down is show here.

by the Long Duration Energy Storage (LDES) procurement by EirGrid, is expected to deliver a substantial volume of flexibility addressing specific system needs, such as security of supply and management of network constraints.

For the mid-term projections, NEDS initiatives have also developed a strong foundation for future consumer- and business-led demand-side flexibility to 2033-2035 by delivering smart meter roll-out, enhancing smart meter data access, and developing a diverse range of tariffs to motivate demand-side flexibility at scale, as well as addressing technology, market and regulatory barriers and uncertainties.

Flexibility growth is currently progressing at a slower pace than originally envisaged under the Climate Action Plan 2023 (CAP23) targets, reflecting wider challenges affecting the energy transition. These include slower uptake of Low-Carbon Technologies (LCTs) (such as EVs and heat pumps) relative to their respective CAP targets as projected by the SEAI, delivery risks in infrastructure and market development, and evolving policy timelines. This reflects a transition from early-stage ambition-setting toward more realistic, evidence-based forecasting grounded in actual market delivery and project pipelines. Unless the deployment of flexible technologies, participation in flexibility markets and demand-side engagement is accelerated materially, the flexibility levels originally envisaged under CAP23 are unlikely to be achieved within the original timeframe.

Since the NEDS was introduced in 2024, Ireland has made clear and measurable progress in building the foundations for flexible electricity use, including:

- Continuation of the large-scale deployment of smart meters and improved data access frameworks.
- Development and improvement of accessibility and diversity of Time-of-Use (ToU) tariffs for residential and business customers.
- The development of flexibility markets, additional procurement mechanisms such as LDES and the launch of demand flexibility products by SOs.
- Deployment initiatives to unlock barriers to flexibility from specific technologies, such as Smart EV charging and a better understanding of the effects of microgeneration on the network.
- Policy and regulatory developments supporting demand-side participation and flexibility markets.
- Increased coordination across key programmes such as the NEDS, the Large Energy-user Action Plan (LEAP), the National Energy Affordability Taskforce (NEAT), and specific EU initiatives like the Agency for the Cooperation of Energy Regulators (ACER's) Flexibility Needs Assessment (FNA) and the Demand Response Network Code implementation.

The NEDS is focused on progressing initiatives that can contribute towards demand flexibility in the short term and hence directly affects a select few demand-side flexibility sources. These sources contribute a large share of the total flexibility, such as flexibility procurement by EirGrid and ESBN, reaching an average of 6.8 GWh daily flexible volume[4] by 2035. NEDS also includes actions to develop the building blocks for the high volume of flexibility expected from residential and commercial customers, either through explicit aggregation or in response to price signals. Comparing the two areas, confidence of certainty in flexibility provided through explicit procurement and committed projects is generally higher than the consumer-led demand-side flexibility, where future participation and technology uptake remain uncertain. Nevertheless, key factors such as central government policies and overall economic conditions are the primary drivers of growth in consumer-led and business-led demand-side flexibility as well as in the improved participation in flexibility.

Flexibility Needs Assessment

In July 2025, the EU Agency for the Cooperation of Energy Regulators (ACER) approved the methodology for Flexibility Needs Assessment, which binds the member states to analyse national flexibility needs in their electricity systems. In accordance with Article 19e of Regulation (EU) 2019/943, as amended by the Electricity Market Design Reform (Regulation (EU) 2024/1747), the CRU, as the National Regulatory Authority, is responsible for adopting the FNA methodology in Ireland and coordinating the assessment of needs by the electricity system operators, EirGrid and ESB Networks. Assessment of flexibility includes analysis of system, transmission and distribution level needs accounting for future growth in demand, generation and system development.

In line with the requirements of Regulation (EU) 2019/943 (as amended by Regulation (EU) 2024/1747), the findings from the FNA will support the development of an indicative national objective for non-fossil flexibility to be defined by DCEE. The outcome of the needs assessment will also identify market design and regulatory barriers to flexibility, which can inform the future policy development and development of flexibility in Ireland. The FNA is also expected to provide a more evidence-based framework for future flexibility targets and system requirements.

FNA is expected to be updated every two years and the first report with the outcome of the assessment is published (CRU2026130) on 24 August 2026.

To continue the growth of demand-side flexibility, delivery of the remaining NEDS actions should maintain a concentrated effort on the development of flexibility markets and other critical enablers for flexibility. These actions should continue to be progressed in coordination with other existing programmes and initiatives to support efficient delivery and avoid duplication. To foster early

[4] Calculated as flexibility volume available on an average day.

growth in flexibility, especially at the rates aligned to the most ambitious "Enhanced Growth" scenario, procurement must be timely, appealing, and straightforward for flexibility developers. Further policy development may be required to enable and accelerate growth in fundamental flexible resources, such as EVs, heat pumps and other demand-side response technologies, including through incentives, measures to address supply chain and infrastructure challenges, and support for consumers and businesses where appropriate. The FNA is also expected to provide a more evidence-based framework for future flexibility targets and system requirements, further informing the development of demand-side flexibility through targeted procurement and wider policy initiatives.

As implementation of the current NEDS programme enters its final phase, the remaining CRU coordination activities are expected to focus on supporting delivery of outstanding actions, engagement through the NEDS Implementation Group, and publication of the next and final NEDS Annual Update report. Any significant changes or updates to the projections in this report, if required, would be reflected through those remaining NEDS reporting arrangements. Following completion of the current NEDS reporting cycle, future flexibility planning is expected to be informed increasingly by the FNA process and wider policy initiatives.

Any longer-term governance or coordination arrangements for flexibility-related policy and implementation activities beyond the current NEDS programme, including any follow-on programme, successor strategy, or future iteration of NEDS, should be considered through an all-of-Government lens and taken forward through a Government-led governance structure. This would allow the future programme to address the wider policy levers that sit outside the regulatory sphere, including the National Energy Affordability and Transition (NEAT) programme, enterprise policy, transport decarbonisation, heat policy, consumer participation, and broader objectives relating to energy efficiency and demand reduction.

This report follows the latest NEDS Annual Update (CRU202628) published in June 2026, which provides qualitative progress tracking of 53[5] NEDS actions.

[5] Note that a total of 51 actions were included in the NEDS Decision Paper (CRU202467). However, two of these actions (Actions No. 1.11 Microgeneration operational issues, and No. 3.2 Enhanced quality and accessibility of network information) are replicated for two different responsible bodies (EirGrid and ESBN). The tracking of these actions will be reported separately; hence the total here appears as 53 actions.

Public / Customer Impact Statement

Ireland's electricity system is changing rapidly due to economic growth, geopolitical developments and decarbonisation efforts. Increasing proportion of electricity supply from variable renewable generation and electrification of demand requires flexibility to balance the supply and demand, matching flexible consumption to the available generation. Flexibility can help reduce costs, maximise the use of renewable energy, improve energy security and support network efficiency. This report explains how flexibility is expected to develop over the coming decade and how the National Energy Demand Strategy (NEDS) is contributing to that progress.

As part of the development of the Government's Climate Action Plan, recognising the challenges faced by the energy system in Ireland, the CRU proposed the development national demand strategy. The Government included an action to develop a national demand strategy in the Climate Action Plan, and requested that the CRU lead its development. In response to the CAP23 action assigned by the Government, the CRU launched the NEDS in July 2024. The aim of the strategy is to enhance Ireland's energy demand flexibility with a view to supporting a more sustainable, cost-effective, and secure energy system. In essence, if a high proportion of customers can shift their energy consumption to times when there is a significant quantity of electricity being generated by renewable generation, customers can benefit and reductions in carbon emissions can be achieved, even as overall demand for energy increases.

Demand flexibility enables and empowers energy consumers to increase their use of renewable energy whilst also reducing demand during times of high-carbon intensity on the energy system. This ability to adjust consumption patterns in response to fluctuations in renewable energy output and network conditions is crucial to decarbonising Ireland's energy system. In the long term, greater use of flexibility will result in a major change to how the energy system operates and in how customers organise their energy usage, from domestic households to businesses and large industrial users of energy. For example, an electric vehicle or a battery could automatically charge overnight when electricity demand is lower or when there is a high proportion of renewable generation locally or on the system.

The NEDS decision identified 53 high impact, short-term actions and 3 Government Department recommendations. Following the publication of the strategy, the NEDS entered its implementation phase. The CRU has committed to report on the progress of NEDS implementation, including the impact of NEDS actions on the growth and development of demand flexibility in Ireland. This report provides an updated estimate of demand flexibility from residential, industrial, commercial and utility sectors through 2035. Forecasts incorporate the latest views on decarbonisation progress across sectors, the uptake of electric vehicles, heat pumps, energy storage, and microgeneration, as well as progress on the use and procurement of flexibility in the energy sector.

As a result of a combination of policy measures, incentives and market developments, Ireland is expected to make steady progress with significant growth of demand-side flexibility through 2035, albeit at a slower pace than the CAP23 targets originally anticipated. Delivery of the NEDS contributes to the progress by directly impacting the growth in flexibility procured by EirGrid and ESBN, which is used to manage network stress and maximise the use of renewable generation. The NEDS is also developing the building blocks across the energy sector, such as ToU tariffs and smart EV charging services, to enable consumers and businesses to participate in the energy system and access benefits from flexible demand.

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Glossary of Terms and Abbreviations

Abbreviation or Term	Definition or meaning
ACER	Agency for the Cooperation of Energy Regulators
ADMD	After Diversity Maximum Demand
AIRAA	All-Island Resource Adequacy Assessment, published by EirGrid
BER	Building Energy Rating
BMS	Battery Management System
BtM	Behind-the-Meter
CAP / CAP23	Climate Action Plan; CAP23 refers specifically to Ireland's Climate Action Plan 2023.
CEER	Council of European Energy Regulators
CPPA	Corporate Power Purchase Agreement
CRU	Commission for Regulation of Utilities
CVR	Conservation Voltage Reduction
DCEE	Department of Climate, Energy and the Environment
DETE	Department of Enterprise, Tourism and Employment
D-Network	Distribution Network
DS3	Delivering a Secure, Sustainable Electricity System
DSO	Distribution System Operator
DSR	Demand Side Response
DSU	Demand Side Unit
eBus	Electric bus
eHGV	Electric Heavy Goods Vehicle
eLCV	Electric Light Commercial Vehicle
EirGrid	Ireland's Transmission System Operator (TSO)
ESBN	ESB Networks (DSO)
EU	European Union
EV	Electric Vehicle
FNA	Flexibility Needs Assessment
GEP	Green Energy Park
GNI	Gas Networks Ireland
GO	Guarantee of Origin

GW / MW / kW	Gigawatt / Megawatt / Kilowatt
GWh / MWh / kWh	Gigawatt-hour / Megawatt-hour / Kilowatt-hour
I&C	Industrial and Commercial customers
IDA	IDA Ireland; Ireland's inward investment promotion agency
KPI	Key Performance Indicator
kWp	Kilowatt-peak
LCTs	Low Carbon Technologies
LDES	Long Duration Energy Storage
LEAP	Large Energy User Action Plan, published by DETE
LEU	Large Energy User
MO	Market Operator
NECP	National Energy and Climate Plan
NEDS	National Energy Demand Strategy
OEM	Original Equipment Manufacturer
PV	Photovoltaic
RES	Renewable Energy Sources
SEAI	Sustainable Energy Authority of Ireland
SEM	Single Electricity Market
SoC	State of Charge
SOEF	Shaping Our Electricity Future
SO	System Operator
SONI	Northern Ireland's electricity Transmission System Operator
SSWG	Smart Services Working Group
ToU	Time-of-Use; electricity tariffs that vary by time of day
TSO	Transmission System Operator
V1G	Unidirectional smart charging of electric vehicles
V2G	Vehicle-to-Grid
V2H	Vehicle-to-Home
V2X	Vehicle-to-Everything
ZEVI	Zero Emission Vehicles Ireland

1 Introduction

This report presents the CRU's updated forecasts of demand-side flexibility in Ireland for the period 2025-2035, to quantify the impact of NEDS and contribute towards the implementation of NEDS Action 0.3. The structure of the report is as follows:

- Section 1 provides the context for demand-side flexibility forecasts by covering the NEDS requirements for forecasting flexibility and the background of the role of flexibility in the energy system and achievements in NEDS implementation to date.
- Section 2 outlines the methodology that has been adopted for forecasting demand-side flexibility, explaining the updated approach to flexibility forecasts, including the structure, flexibility sources used in the estimation, mapping flexibility resources to NEDS Areas of action, and a description of the scenarios.
- Section 3 presents the results of the estimation and compares them with previous projections outlined in the NEDS Decision.
- Section 4 concludes the report and outlines considerations relevant to future updates of the demand-side flexibility forecasts and discusses factors that may influence further growth of flexibility in Ireland.
- The Appendix provides further details on projected demand-side flexibility for 2030 and 2035, and descriptions of the models and individual forecasts for the identified flexibility sources.

1.1 NEDS Overview

The CRU published Ireland's first NEDS on 15th July 2024 (CRU202467). Originally, the CRU proposed to develop national demand strategy in recognition of challenges faced by the Irish energy system. Consequently, CRU developed this strategy to meet both the specific ambition set out in the Government's CAP23[6] under an assigned CRU action (EL/23/24) to "complete and publish an electricity demand side strategy and implementation plan", and to support wider decarbonisation and security of supply objectives. The NEDS identified 53 actions assigned to a range of stakeholders for completion, with the overarching aim of enhancing Ireland's energy demand flexibility through a coordinated phased approach.

[6] Climate Action Plan 2023

NEDS Actions address the development of flexibility across a range of mechanisms and sectors. Forecasting flexibility potential across these sectors and mechanisms is essential to understand the impact and effectiveness of NEDS and identify areas where further work is required. Under Action 0.3 of the strategy, the CRU has also committed to reporting on the progress of the NEDS implementation, including tracking the progress of actions and impact of the NEDS on flexibility.

The primary objective of this report is to present the actual progress achieved to date from the implementation of the NEDS by providing an updated forecast of demand-side flexibility, using an improved methodology and incorporating scenario-based uncertainty representation.

1.2 Why demand flexibility matters

As energy systems evolve to accommodate more renewable energy generation, especially wind and solar, and the electrification of major demand sectors, such as transport and heating, demand flexibility is becoming an essential component of a low-carbon energy system. In parallel, overall electricity demand is increasing. Challenges arise as renewable energy generation can vary depending on weather conditions, and demand is often highest at times when renewable output is low, but yet the energy system needs to remain stable and reliable at all times. Therefore, demand-side flexibility helps address these challenges by shifting electricity use to times when renewable energy is available, reducing pressure on the system during peak demand, and ultimately lowering costs and carbon emissions. It is an effort to match supply and demand more efficiently.

Demand flexibility not only helps to match demand with available supply but also plays a critical role in managing stress on electricity networks. To maintain a reliable supply for customers, both the transmission and distribution networks must be built with sufficient capacity to meet peak demand levels. By reducing peak demand through flexibility, network operators can defer or avoid costly reinforcement works, such as upgrading cables and transformers to higher capacities. This in turn lowers the overall cost of running the network, minimises disruption to customers, and can accelerate the connection of new demand onto the system.

Beyond the wider system and network benefits, consumers and businesses can directly benefit from being flexible and adjusting their electricity use. Price signals, such as ToU tariffs and network charges, encourage customers to move demand from the peak to off-peak periods by reducing the prices during off-peak periods in exchange for higher prices during peak periods. Responding to these signals can result in immediate savings on bills. Alternatively, SOs may procure flexibility services directly, paying providers to adjust their consumption or generation when needed, thereby creating an additional revenue stream for flexibility market participants.

1.3 Flexibility targets

To encourage the growth of demand flexibility in Ireland, CAP23 set an ambitious target for 15-20% of electricity system demand to be flexible by 2025 and 20-30% by 2030. This can be interpreted as 877-1490MW of projected system peak demand in 2030 or 16-24GWh of averaged daily total electricity requirements in 2030 as assessed in 2026[7].

Setting flexibility targets as a percentage of electricity demand can be a useful policy tool for establishing an initial strategic ambition and signalling the scale of flexibility required from the energy system. However, a single flexibility target does not identify the specific system needs that flexibility is intended to address, nor does it distinguish between different types of flexibility that deliver different benefits. For example, the flexibility required to respond quickly to short-term system events may differ from the flexibility required to shift large volumes of energy over longer periods. Consequently, while percentage-based flexibility targets remain useful high-level indicators, they should be complemented by assessments of specific system needs and flexibility requirements.

From the onset of NEDS development, CRU has developed a definition for flexibility to most accurately capture the objective of NEDS and enable monitoring progress against the CAP flexibility target. Through consultation, it was decided to use energy volume shift as a definition of flexibility which represents the volume of energy moved from one point in time to another within a day. Looking ahead, flexibility planning in Ireland will increasingly be shaped by European developments. In recognition of the potential of demand-side response and other sources of flexibility to meet the needs of the electricity system, ACER has developed a methodology for FNA and requires all SOs across the Member States to implement it as per Article 19e of Regulation (EU) 2019/943[8]. Following the development of an appropriate methodology, SOs are required to model their system needs and derive capacity profiles of flexibility needs across several applications: reducing curtailment to enhance Renewable Energy Sources (RES) integration, supporting system stability by delivering system ramping needs, and short-term flexibility needs. The first results of the assessment are expected to provide an evidence base for identifying shortfalls in flexibility to meet system needs and inform future national objectives for flexibility. If a shortfall exists, as per Article 19(g) of Regulation (EU) 2019/943, Member States may apply non-

[7] Calculated as 20% and 30% on the EirGrid’s Low and High scenarios for the transmission level peak demand forecast for Ireland and the total electricity requirement in 2023 in 2030 as forecasted by EirGrid's 2026 All Islands Resource Adequacy Assessment.

[8] Regulation - 2019/943 - EN - EUR-Lex

fossil flexibility support schemes to address the shortfall for the specific and justified needs as identified by the FNA.

The outcome of the FNA will inform the national targets for non-fossil flexibility which will be published six months after the FNA outcomes and can be used as comparable milestones for tracking flexibility provided through explicit procurement routes with EirGrid or ESBN. The FNA is therefore expected to provide a system-needs-based framework for setting future flexibility targets.

1.4 NEDS Achievements to date

The introduction of the NEDS in 2024 has strengthened both existing and new initiatives to develop flexibility and accelerated the growth of flexibility. Since the publication of the NEDS Decision, Ireland has made clear and measurable progress in building the foundations for flexible electricity use and in the direct procurement of flexibility by SOs; increasing the role of demand-side flexibility in managing the energy system. By completing 34 actions out of 53, the NEDS has delivered on the following significant achievements:

ESBN Demand Flexibility Product and procurement

One significant contribution to flexibility is the progress made on ESBN's Demand Flexibility Product, particularly the completion of Action 2.11 on DSO flexibility procurement. ESBN completed the second-stage consultation and, following a CRU decision in May 2025, transitioned into live procurement. The first procurement phase targets up to 109 MW across 16 locations[9], and this is an important step towards ESBN's longer-term ambition of 500 MW of flexible capacity and a clear example of the strategy moving from policy design to the delivery of real system flexibility.

Long Duration Energy Storage (LDES) procurement

In fulfilment of Action 2.5, EirGrid published an LDES procurement consultation in October 2025. While the action milestone has been met, the procurement process is ongoing, with EirGrid progressing towards procuring up to 500 MW of LDES. This is a significant achievement because LDES can shift energy across time, reduce renewable curtailment and redispatch, and strengthen security of supply during periods of low renewable output.

[9] The outcome of the procurement is expected to be announced in Q3 2026 and not available at the time of writing.

Smart meter rollout and smart meter data access code

As part of the progress under Action 1.9 and previous activities prior to the NEDS, the National Smart Metering Programme has now delivered more than 2.1 million smart meters. Together with the Smart Meter Data Access code that was published in February 2025, it is a critical enabler to flexibility as it underpins smart tariffs, automation, data-driven services, and future customer participation in flexibility.

Improving participation and performance from Demand Side Units

Progress has also been made in strengthening existing routes to market for flexibility through the completion of Action 2.3 which aimed at increasing flexibility provided by Demand Side Units (DSUs). EirGrid and SONI published a Transmission System Operator (TSO) Demand Side White Paper and a related plan of work to improve DSU participation and performance, remove barriers, and clarify the technical and market changes needed to support greater flexibility from demand-side providers.

Large Energy Users connection policy

The completion of Action 3.1 on the new Large Energy Users (LEUs) connection policy is another major strategic achievement. The CRU published the final LEUs Connection Policy Decision in December 2025, establishing a pathway for new data centres to connect while addressing security of supply, system constraints, and renewable targets.

Contribution to flexibility

In 2024, in support of the NEDS Consultation and the subsequent NEDS Decision paper, the CRU also carried out an initial assessment of the potential for demand flexibility across the 3 focus areas of the NEDS and estimated how demand flexibility may develop through to 2030. The assessment of potential flexibility included a range of flexibility sources linking the flexibility to the ambition of the CAP targets for the uptake of LCTs, such as EVs and heat pumps, as well as explicit procurement programmes by EirGrid and ESBN.

The refreshed flexibility forecasts, presented in this report, update the original estimation methodology and incorporate the latest views on the trajectories for decarbonisation of demand, such as transport and heating, and a more realistic view of uncertainty and the delivery of projects and programmes.

Achievements from the wider developments across the flexibility landscape and the progress of NEDS demonstrates the shift from policy design for flexibility to practical policy implementation and delivery of flexibility for the energy system. Change in the methodology for forecasting flexibility also reflects the transition from a high-level ambition to a more practical and realistic delivery.

2 Methodology

This section outlines the approach that has been adopted to forecast demand-side flexibility, including the structure of the modelling framework, the flexibility sources included, how NEDS actions map to those sources, and the scenarios used to represent uncertainty. Detailed model descriptions and individual source projections are provided in the Appendix.

2.1 Framework for forecasting flexibility

The framework developed for forecasting demand-side flexibility in Ireland builds on the original methodology used to estimate flexibility in support of the NEDS Consultation and subsequent Decision. The updated framework for flexibility forecasts is based on a bottom-up approach and uses an expanded set of 19 models to represent different sources of flexibility across three categories: residential, commercial, and utility-scale. The resulting forecasts should be interpreted as directional estimates for potentially available flexibility based on the latest view of developments around flexibility and should not be treated as a definitive prediction of future flexibility. Table 1 lists the individual sources included in the estimation framework, their grouping, and the technology assumed for the estimation of each source.

Table 1: Breakdown of the flexibility sources and their associated cohorts

Flexibility Source	Flexibility cohort	Included technology
Residential customers		
Behavioural	Behavioural flexibility	Smart meters and price signals driving change in behaviour
Heat	EV and smart appliance flexibility	Demand response from heat pumps in response to price signals or aggregation
EV	EV and smart appliance flexibility	Smart EV charging in response to price signals or aggregation
V2X	EV and smart appliance flexibility	Bi-directional smart EV charging in response to price signals or aggregation
Generation	Microgeneration and Energy Sharing	Demand response associated with solar PV generation
Storage	Microgeneration and Energy Sharing	Battery energy storage paired with PV to maximise self-consumption or in response to price signals
Energy Sharing	Microgeneration and Energy Sharing	Change in demand to match local generation in response to aggregation or prices in a community energy zone
Commercial and industrial customers		
Demand Response	Broadening Demand Side Unit participation	Medium to large industrial premises aggregated for participation in the capacity market.
Heat	Industrial and commercial heat	Industrial customers switching from electrode boilers to gas boilers and demand response from heat pumps in commercial properties in response to price signals or aggregation

EV	Electric road transport flexibility	Smart charging of light commercial vehicles, electric HGVs and buses in response to price signals or aggregation
V2X	Electric road transport flexibility	Bi-directional charging of light commercial vehicles, electric HGVs and buses in response to price signals or aggregation.
EV hubs	Electric road transport flexibility	Publicly available EV hubs with multiple high-powered chargers and variable pricing.
Storage	On-site generation and storage	Assumed to be part of DSU.
Generation	On-site generation and storage	
Heat Networks	Industrial and commercial heat	District heating with thermal storage, gas-powered combined heat and power, and electrode boilers.
Green energy park	Broadening Demand Side Unit participation	Mix of industrial and commercial demand co-located on a single site with renewable generation, storage and renewable energy sources.
LEUs	Broadening Demand Side Unit participation	Stand-alone LEUs with BtM generation, storage and or demand flexibility.
Utility-scale flexibility		
ESBN flexibility procurement		Energy storage and demand response procured by ESBN
EirGrid flexibility procurement		Battery energy storage procured through capacity market, DS3 System services and Long Duration Energy Storage auctions.
Network flex		Conservation Voltage Reduction to manage demand on the electricity distribution network.
Pumped storage		Pumped hydro storage participates in electricity wholesale markets through daily charging and discharging cycles.

Flexibility sources that represent a large number of individual units, such as EV chargers and heat pumps, can have multiple routes to market for generating value. For example, these sources may respond to price signals or can be managed by aggregators to deliver flexibility services. To model these resources, various parameters are used to estimate their flexibility, including a flexibility rating in terms of how much flexibility a unit can provide, flexibility duration to indicate how long they can provide it for, and participation rates. These parameters can be adjusted to reflect outputs from NEDS actions or broader policy developments and are used to represent the impact of different uncertainty scenarios described in section 2.3.

Other flexibility sources with a known quantity of flexibility in the pipeline, but yet to be procured or built, such as EirGrid's LDES procurement or the development of pumped storage, are represented as a timeseries of flexibility volume. Uncertainty in the growth of flexibility from these sources is reflected in the timing of when the relevant milestones are reached and in the rate of growth towards those milestones.

Data used to model these flexibility sources are based on publicly available information and information provided by stakeholders through direct engagement. NEDS actions are also mapped to the relevant flexibility sources to inform the impact of the actions on the projections of flexibility for those respective sources.

2.2 Mapping of NEDS to flexibility sources

The 53 NEDS actions address the three key focus areas as outlined in Figure 2 to develop and enhance flexibility:

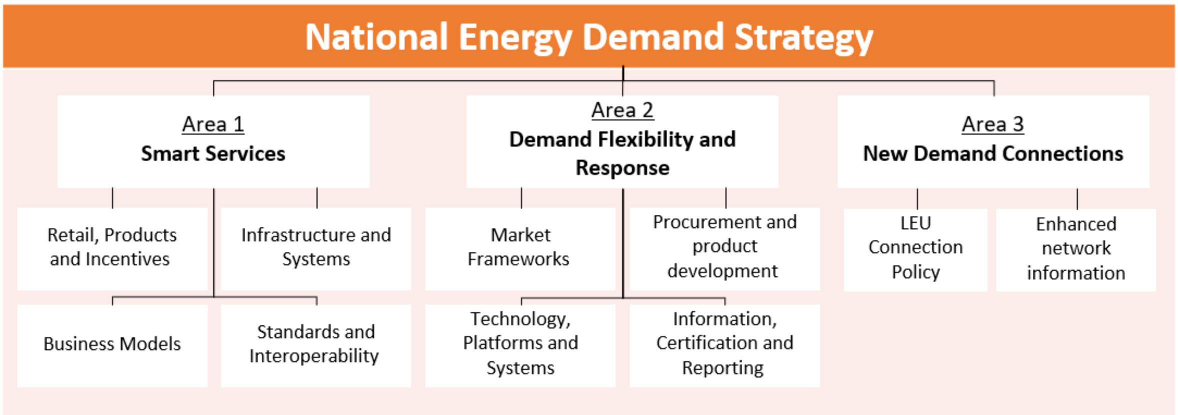


Figure 2: Overview of three Focus Areas of the NEDS

These areas focus on specific aspects of demand-side flexibility and can either have a direct impact on the volume of flexibility from a particular source or indirectly contribute towards the enabling building blocks that support growth in the uptake of flexible resources and customer participation. A direct impact includes actions that address the development of routes to market or drive the growth in flexibility from the specific source (e.g. procurement volume for energy storage). An indirect impact includes actions that have an enabling effect (e.g., the accessibility of data or the understanding and addressing of challenges to uptake and participation). Whilst NEDS areas focus on the mechanisms for flexibility and do not directly map to the categories of flexibility, the subsections below map out how NEDS areas impact flexibility growth and development.

Impact and relevance of Area 1: Smart Services

Actions that fall within NEDS Area 1 focus on encouraging residential and business customers to participate in demand-side flexibility. This includes promoting ToU tariffs to help customers shift their energy use away from peak times to off-peak periods. While price signals mainly influence behaviour directly, they are also essential for enabling behind-the-meter flexibility resources like smart EV charging, heat pumps, and bidirectional charging. The rollout of Smart Meters and access to their data are necessary for customers to join ToU tariffs and are key to unlocking flexible demand through devices such as EVs and heat pumps. These devices can respond to price signals or be pooled together for flexibility services, including flexible product bundles from retail suppliers.

Impact and relevance of Area 2: Demand Flexibility and response

The focus of the actions in NEDS Area 2 is on the incentives and measures to provide demand response for specific system needs as identified and procured by the SOs. This includes measures that support how flexibility markets operate, such as developing new products and improving market access. In addition to the enabling measures, this area also includes the explicit procurement of services, such as LDES by EirGrid and Demand Flexibility Product development by ESBN, which is directly intended to increase the volume of flexibility on the system.

Impact and relevance of Area 3: New Demand Connections

Two sources of flexibility that are directly impacted by the initiatives in NEDS Area 3 are the LEUs and green energy parks (GEPs). Specifically, Action 3.1 was expected to deliver significant demand flexibility from LEUs by specifying the connection requirements.

Overall, this mapping shows how the NEDS actions inform the flexibility sources in the forecasting framework. These assumptions remain subject to uncertainty, particularly where future flexibility depends on wider economic conditions, policy delivery, technology uptake and the pace of implementation across the relevant NEDS actions. Section 2.3 therefore sets out the three scenarios used to represent this uncertainty in the forecasts. Further detail on how individual NEDS actions and scenario assumptions are applied to each flexibility source is provided in the Appendix.

2.3 Scenarios for 2025-2035

To account for uncertainty in flexibility growth, three scenarios have been introduced to describe how policy developments and market outcomes could affect it. The three scenarios, “Delayed Delivery”, “Expected Delivery”, and “Enhanced Growth”, are intended to reflect the challenge presented by uncertainty in projecting the flexibility from each of the identified sources.

Each scenario incorporates different assumptions that influence the extent to which flexibility can be integrated into the power system, for example, the pace of decarbonisation, technology adoption, regulatory intervention, potential progress in project completion, and the success of flexibility procurement. These scenarios serve as analytical frameworks for assessing the range of possible outcomes, highlighting the sensitivity of flexibility projections to policy evolution, market readiness, and customer engagement. Table 2 provides a high-level overview of the main characteristics and implications of each of these three scenarios.

Table 2: High-level description of the scenarios for the projections of flexibility.

Scenario	Overall description
Expected Delivery	Central scenario, assuming the existing and already-commenced measures and policies for decarbonisation and flexibility are implemented in a timely manner. Delivery of projects and programmes across the industry is proceeding without a significant delay. Market, regulatory and participation barriers to flexibility are being addressed.[10] Maintaining a slower than CAP growth rate on the uptake of LCTs in line with the "existing measures" scenario from the SEAI's National Energy Projections[11].
Delayed Delivery	Represents the lower bound of uncertainty and assumes the delayed implementation of existing policies and programmes due to complexity in design and implementation, and the uptake of demand-side flexibility is continually hindered by barriers, such as supply chain bottlenecks, infrastructure readiness and wider economic conditions. Aligns with the "with existing measures" scenario from the SEAI's National Energy Projections with a 2-year delay on the uptake of EVs, heat pumps, district heating and includes delayed impacts from existing policies and policies with a clear commitment to proceed.
Enhanced Growth	Represents the upper bound of uncertainty and a high-ambition trajectory. Assumes additional measures and over-performance of the existing measures to enhance further growth in demand-side flexibility, a further reduction of barriers to participation and increased support for the delivery of programmes and projects to enable flexibility. An improvement on the expected growth rate and scale of LCT deployment, aligning to the "With Additional Measures" scenario from the SEAI's National Energy Projections and includes impacts from existing policies, policies with a clear commitment to proceed, and policies in development with a realistic chance of being committed to.

These scenarios have a specific effect on the modelling for each flexibility source, as described in the Appendix. As the implementation of the NEDS progresses and associated actions are completed, these scenarios may evolve and necessitate further adjustments in response to outputs from the actions, insights from the NEDS stakeholders, and broader policy development.

2.4 General assumptions, limitations and known gaps

In recognition of the complexity and the scale of the challenge to forecast flexibility across the range of sources, the following key assumptions and simplifications have been applied:

[10] Further review of barriers to flexibility is included in the Flexibility Needs Assessment publication (CRU2026130), August 2026, Flexibility Needs Assessment | CRU.ie

[11] SEAI, National Energy Projections, 2025, National-Energy-Projections-Report-2025.pdf

- No seasonal differentiation is included – all flexibility is assumed to be delivered as and when needed:
    - Demand turn-up/generation turn-down is estimated for periods of high generation that require curtailment or cause localised network constraints.
    - Demand turn-down/generation turn-up is quantified for periods of high demand approaching system margins or causing localised network constraints.
    - Whilst the estimated flexibility is given as an average daily potential, the exact volume of flexibility delivered will depend on the conditions during the day when flexibility is required.
- Implicit flexibility (driven by price signals) assumes a persistent response, which acts as a deterrent to increasing the peak demand (or peak generation) and cannot be "called" or triggered to deal with short-term system needs. In practice, customers may choose to use electricity at a higher rate during peak time due to a change in their behaviour or in response to short-term needs, like caring requirements, therefore reducing the volume of flexibility delivered to the energy system.
- All elements are assumed to be homogeneous, without diversity within each type of flexibility source (i.e. all households are the same, all batteries are of the same size, all battery capacities of EVs are the same) to manage data limitations and complexity of the framework. An element of diversity is represented by the participation or availability rate.
- Flexibility for demand turn-up is assumed to have a utility to deliver useful services by shifting energy use in time, for example heating up water for domestic hot water use, shifting EV charging from other non-peak periods, and not promoting wasteful practices.

If future updates to the flexibility forecasts are undertaken, these assumptions and limitations should be reviewed and reconsidered as new data becomes available, and the implementation of the NEDS actions better informs the granularity of the demand-side flexibility models in this framework. Flexibility from residential and business customers relies on two components with high uncertainty: 1) scale of demand-side technology uptake, such as EVs and 2) the rate of participation in delivering flexibility, either in response to price signals or through aggregation, resulting in a low confidence impact on the projections. However, flexibility sources based on explicit procurement by ESBN and EirGrid as well as dedicated flexibility projects such as pumped storage, result in a higher level of confidence since the procurement and the planning process are already in motion. On average across the three scenarios, higher confidence sources[12] make up 54% of the forecasted flexibility volume in 2030 and 43% in 2035.

Accordingly, the forecast outputs should be interpreted as directional estimates rather than precise predictions. They provide an indication of the likely scale and direction of flexibility growth under the stated assumptions and scenarios, rather than a forecast that future flexibility volumes will be delivered to a particular level of accuracy. Actual outcomes will depend on a range of factors including technology uptake, customer participation, policy development, economic conditions and delivery of relevant projects and programmes.

Due to the current limited availability of data and information about consumer-led flexibility, such as energy storage and smart EV charging, and engagement of aggregators with consumer-led flexibility, the framework focuses only on average daily volume. As a result, the estimation framework doesn't distinguish between drivers for flexibility, such as price signals and aggregation of consumer led flexibility. Similarly, the estimation for industrial and commercial customers does not differentiate between direct participation in flexibility markets or services, or the operation of non-firm connections, with the exception of explicit procurement initiatives by ESBN and EirGrid. Whilst flexibility can be used to address multiple needs on the network, which could be seasonal or daily, the exact timing for flexibility requirement must be identified through extensive network and system modelling. FNA is expected to define these requirements. In the meantime, in alignment with the CAP targets, and to estimate a broad scope of flexibility available, flexibility forecasts in the report are based on an average daily volume.

2.5 Definition of flexibility

In alignment with the NEDS Decision (CRU202467), the flexibility forecasting framework applies the same definition to describe available flexibility for demand turn-up and turn-down. This definition was proposed and consulted upon during the development of the NEDS to ensure a consistent understanding and interpretation of the term for strategy implementation across the industry. The chosen definition of demand-side flexibility is a proportion of the average daily demand (MWh) that can be flexed, and is defined as follows:

$$\text{Demand Volume Shift (\%)} = \frac{Measure\ of\ flexibility\ (average\ volume\ of\ energy\ that\ can\ be\ flexed\ , MWh)}{Measure\ of\ daily\ total\ energy\ requirement\ (Average\ Daily\ Consumption, MWh)}$$

[12] Higher-confidence sources are defined for this purpose as explicit procurement and committed/dedicated flexibility projects, as categorised in Appendix C

Unlike the estimation of flexibility for the NEDS Decision, the updated estimation framework differentiates between demand turn-up and demand turn-down flexibility to represent the asymmetry and interdependency of flexibility from some of the sources. For example, Figure 3 shows a typical demand profile for a residential heat pump delivering space heating throughout the day and heating up domestic hot water in the storage tank twice a day.

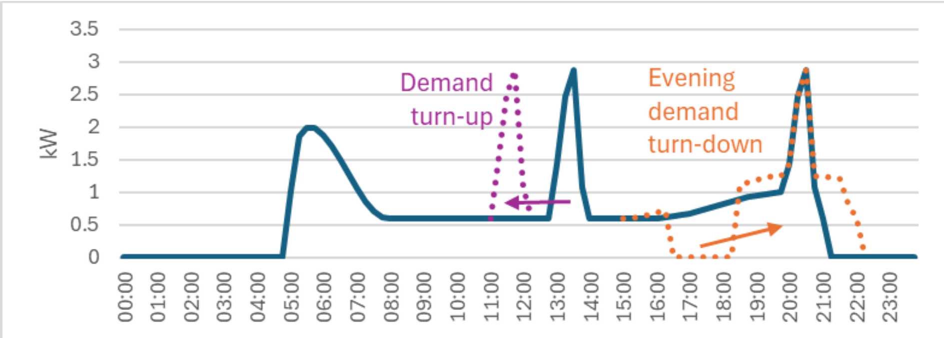


Figure 3: Example of demand-side flexibility from a single residential heat pump with an asymmetrical turn-up and demand turn-down.

Demand turn-up can be delivered by shifting the schedule for the hot water cycles by a few hours without impacting the availability of hot water for the residents or interfering with the space heating. Demand turn-down can be delivered by pausing the heating to reduce consumption during the evening peak demand period followed by increased demand for space heating, whilst still running the domestic hot water cycle as scheduled.

3 Demand-side flexibility forecasts

Building on the methodology described in Section 2, this section presents updated projections of demand-side flexibility across three scenarios over the extended horizon to 2035.

The updated projections show that demand-side flexibility has continued to grow since the NEDS was introduced and supported by the progress in the procurement of flexibility by SOs, smart metering rollout, and implementation of enabling policy. Figure 4 presents the updated forecasts for demand turn-up (left figure) and demand turn-down (right figure). Under the central "Expected Delivery" scenario (green line), total turn-up and turn-down flexibility is projected to approximately double by 2030. Beyond 2030, availability of demand turn-up is greater than turn-down availability, reflecting on the increased proportion of flexibility sources with asymmetrical shift in flexibility.

While the trajectories fall below the CAP23 target of 20–30%, the updated forecasts are grounded in actual delivery experience and project pipelines, representing a more realistic and evidence-based view of how flexibility should develop. Furthermore, following the completion of the FNA, there will be an opportunity to introduce additional support measures to deliver on the non-fossil flexibility to meet the system needs identified by the SOs. This flexibility will be additional to the current trajectories.

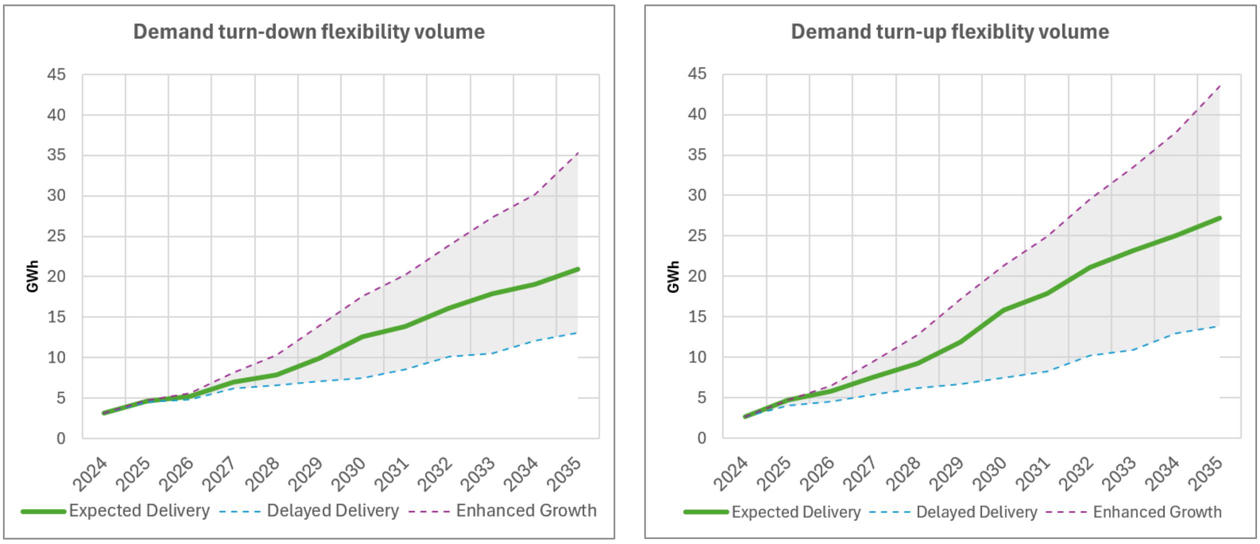


Figure 4: Total volume of flexibility average daily energy required across three scenarios for flexibility forecasts between 2024 and 2035 as projected in 2026.

Figure 5 provides further detail of the projections for demand-side flexibility from individual flexibility sources, grouped into cohorts similar to the approach for the estimation of flexibility in the NEDS

Decision[13]. A specific breakdown by volume from each source grouping for 2025, 2030, and 2035 is presented in Figure 6.

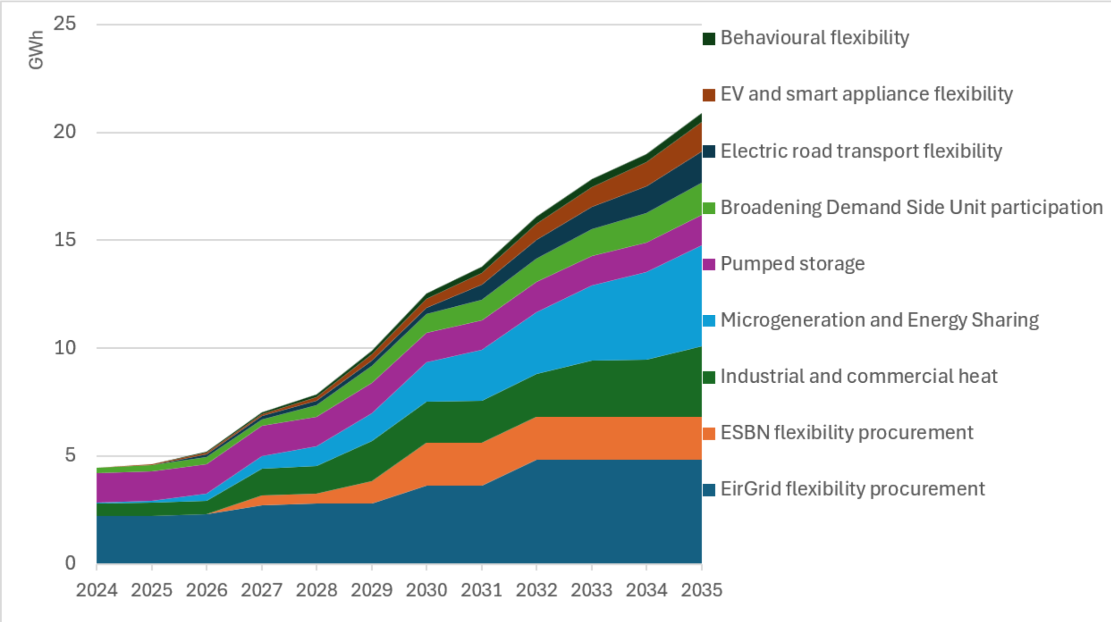


Figure 5: Updated estimate of demand-side flexibility for the central "Expected Delivery" scenario. Projections for each flexibility source are grouped in a similar cohort to estimation for the NEDS Decision paper, and with an extended horizon to 2035.

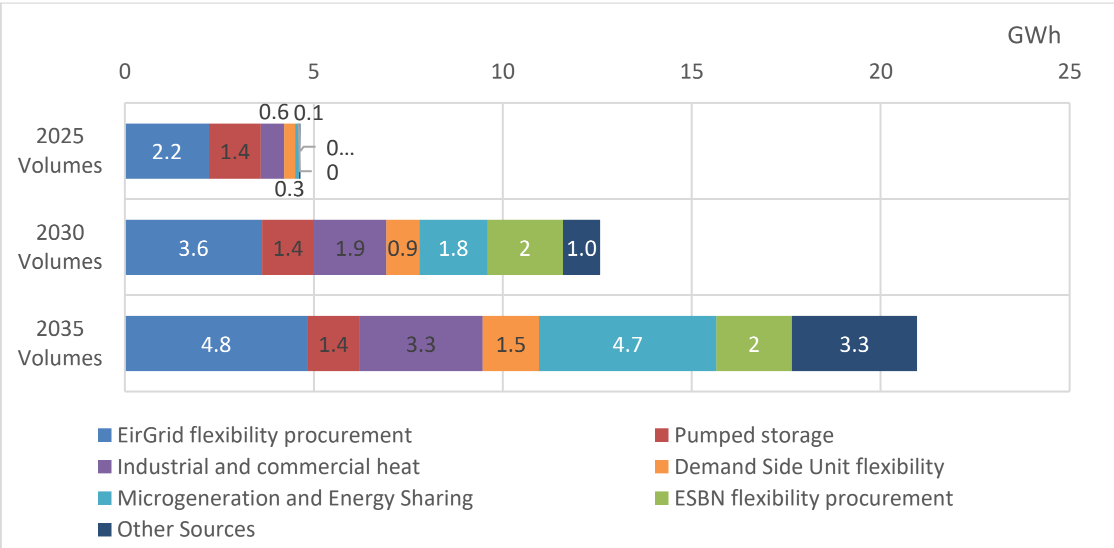


Figure 6: Contribution from the cohorts of flexibility to the demand turn-down flexibility volumes in 2025, 2030 and 2035 as estimated for the central "Expected Delivery" scenario. Other sources include electric road transport, EVs and Smart Appliances, Behavioural flexibility, and LEUs.

[13] A summary of the previous estimates of flexibility for the NEDS Decision can be found in the appendix and in the NEDS Decision document (CRU202467)

Leading up to 2030, explicit procurement by SOs is expected to deliver the most significant proportion of flexibility on the system, closely followed by commercial and industrial heat and pumped storage. In the early 2030s, it is anticipated that consumer-led flexibility will catch up and deliver nearly half of the projected flexibility. However, it is important to note that projections on consumer-led flexibility under all scenarios have lower confidence compared to explicit procurement by SOs as it relies on the combined success factors of maintaining and accelerating the uptake of LCTs and the decarbonisation of demand, customer's participation in flexibility and realisation of benefits of flexibility.

EirGrid flexibility procurement

The estimation provided in the NEDS Decision paper in 2024 used EirGrid's Shaping Our Electricity Future Roadmap[14], which projected 3.2GW of energy storage by 2030. The latest estimation of 1.57GW by 2030 is based on the current pipeline of the storage capacity procured under the capacity market and DS3 services as reported in the latest All-Island Resource Adequacy Assessment[16] (AIRAA), with the addition of the capacity from EirGrid's LDES procurement[15] consultation.

EV and smart appliance flexibility

This cohort of flexible resources includes flexibility from residential heat pumps and from residential EV charging, including Vehicle-to-Everything (V2X) capability. The estimation provided in the Decision paper was based on the CAP targets for the uptake of heat pumps and EVs, trajectories for which have subsequently been assessed by the SEAI[16] and deemed to be much lower than the original CAP targets set. There was also a change in the EV flexibility methodology by shifting the focus from the number of vehicles to the number of compatible chargers that can support smart charging and V2G. In the updated forecast of flexibility, EV and smart appliances are expected to reach 420MWh by 2030 and over 1.3GWh by 2035 for the central "Expected Delivery" scenario.

Pumped storage

The current forecasts of pumped storage flexibility are based on the updated installed capacity and construction timelines for future projects[17] in addition to the existing capacity at Turlough Hill pumped storage facility. At the time of the NEDS Decision, the expected future additional pumped storage capacity was 68MW higher and the expected year for commissioning was 2030.

[14] Shaping Our Electricity Future | EirGrid
[15] Long Duration Energy Storage (LDES) Procurement Mechanism Consultation | EirGrid Consultation Portal
[16] SEAI, National Projections, 2025 National-Energy-Projections-Report-2025.pdf
[17] About Silvermines Hydro - Our Progress. July 2026

Considering the progress to date and the uncertainty around the remaining phases of project development, particularly the material consenting, financing and construction risk, central “Expected Delivery” scenario assumes no additional pumped storage to be operational before 2035. However, the high ambition “Enhanced Growth” includes the updated expectation is for the additional 296MW to be operational by 2033.

Microgeneration and Energy Sharing.

A significant increase in potentially available flexibility in this cohort is driven by the addition of energy storage uptake by residential customers with 50% of new PV customers also installing energy storage[18]. This addition of residential energy storage results in over 780MW of turn-down capacity by 2030 and close to 2GW by 2035 under the central “Expected Delivery” scenario.

[18] How the UK & Ireland solar PV and residential BESS market compares with Australia

4 Conclusion and further considerations

Ireland has made meaningful progress in enabling demand-side flexibility, and the overall trajectory remains positive. The findings of this report indicate that Ireland has made clear and measurable progress in putting in place the foundations necessary for demand-side flexibility to grow. The NEDS has supported progress in delivery of key enablers, including smart metering, improved data access, more diverse tariff offerings and the development of flexibility products and procurement routes. In that context, the report suggests that Ireland is moving from early ambition-setting towards a more practical delivery phase for flexibility.

At the same time, the report shows that the indicative forecasts show flexibility growing at a more gradual pace than originally envisaged under the CAP23. This reflects wider factors affecting the energy transition, including the slower uptake of key LCTs, delivery risk across infrastructure and market development, and prevailing economic conditions. The findings, therefore, do not point to a lack of progress; rather, they reflect a transition to more realistic, evidence-based forecasting grounded in actual market delivery, project pipelines, and implementation experience. These forecasts will continue to evolve and account for new evidence as implementation of NEDS and other programmes progress.

From a NEDS delivery perspective, the implication is that the strategy has been effective in establishing the building blocks for flexibility and in progressing some of the most important direct routes to flexibility, particularly through SO procurement and market development. The next phase of delivery should consider converting these foundations into higher and broader participation from households, businesses, and LEUs. This will require the continued delivery of actions that directly increase flexibility volumes, alongside sustained progress on the enabling measures that support customer participation, smart services, and technology uptake that will support the realisation of the central “Expected Delivery” scenario. Critically, enabling flexibility growth becomes increasingly dependent on the customer participation, the scale of electrification, technology uptake and engagement with the flexibility services and proactive response to price signals. Additional incentives and concentrated effort to increase the consumer- and business-led flexibility would be essential to enable the ambitious “Enhanced Growth” scenario to materialise.

In the final phase of the NEDS, any significant changes or updates to the projections, if required, would be included in the next and final NEDS Annual Update report, reflecting the latest evidence, delivery experience for the remainder of the current NEDS reporting cycle. For example, these changes could include:

- Update modelling assumptions as new evidence and data becomes available.
- Incorporate the latest outputs from NEDS Actions and the associated activities.
- Adjust participation, capability, and technology readiness assumptions to reflect progress in consumer engagement, supplier offerings, and operational learnings from early pilots.
- Use insights from the remaining NEDS Implementation Group engagement to validate assumptions and inform any updates reflected through the remaining NEDS reporting arrangements.
- Integrate developments in electrification pathways, storage technologies, fleet charging, and community energy to ensure the framework remains representative of future system dynamics.

In the context of demand-side flexibility in Ireland, this report also highlights the importance of policy development and coordination in shaping future growth. While the NEDS has a focused role in progressing short-term actions that contribute to flexibility, the pace and scale of future flexibility growth will continue to depend on wider policy, economic conditions, and related programmes. In particular, the findings suggest that future flexibility planning is likely to be shaped increasingly by the FNA, which will provide a more evidence-based view of system requirements and future flexibility priorities. As implementation of the current NEDS programme enters its final phase, the remaining coordination activities are expected to focus on supporting delivery of outstanding actions, engagement through the NEDS Implementation Group, capturing lessons learned and publication of the next and final NEDS Annual Update report as part of orderly close-out of the programme. Thereafter, future flexibility planning is expected to be informed increasingly by the FNA process and wider policy initiatives, including enterprise policy, transport decarbonisation, heat policy, consumer participation, and broader objectives relating to energy efficiency, and demand reduction.

As such, the following areas for development should be considered to support the growth in demand-side flexibility and its contribution to the Irish energy system:

- **Accelerate delivery of flexibility procurement**. Timely implementation of EirGrid and ESBN procurement programmes remains essential, as utility-scale procurement is identified in the report as a major driver of near-term flexibility growth. Clearer and investable routes to market will be important to reduce delivery risk and support confidence among flexibility providers.
- **Improvements in wholesale markets and SEM to encourage flexibility.** Continue to progress SEM and wholesale market reforms that better enable demand-side flexibility, including improved conditions for DSU participation, sharper balancing and settlement signals,

and clearer arrangements for suppliers, aggregators and market participants. Development of these reforms could benefit from alignment with the network tariffs reform, development of flexibility markets and retail market arrangements, recognising that wholesale markets can provide an important route to value but will not, on their own, capture all system and network needs.

- **Convert enabling measures into wider participation.** The delivery of smart meters, data access arrangements and tariff reforms has established the foundations for customer-led flexibility. The next priority is to translate these enabling measures into the broader uptake of smart tariffs, flexibility services and customer participation across residential and commercial sectors by supporting transition through advice, incentives and the promotion of benefits.
- **Strengthen policy support for flexible technologies.** A significant share of future flexibility depends on the uptake of technologies such as EVs, heat pumps, battery storage and smart charging solutions. Continued policy development, including incentives and measures to address supply chain, infrastructure and affordability barriers, will therefore be important to support the growth of these flexible resources.
- **Encourage innovation across the flexibility value chain.** New commercial models, technology propositions and operational processes will be needed to lower participation barriers and make flexibility easier for customers to access. This includes automation to simplify participation, clearer financial offers that make the value of flexibility more transparent, and integrated propositions that combine technology, tariffs and market access. Suppliers, aggregators and technology providers will need to innovate to scale flexibility services, while system operators will also need to integrate flexibility across operations to support efficient market growth, use of flexibility and capture the wider system benefits of flexibility. Tying it all together, market structure and rules for flexibility would have to evolve as well to recognise the complexity of the system and to manage the market balance.
- **Maintain coordination across related programmes and policy initiatives**. The report indicates that flexibility growth is affected by the interaction between the NEDS, LEAP, NEAT, market development, wider electrification policy and European initiatives. Continued coordination across these programmes will be necessary to ensure efficient delivery, reduce duplication, stakeholder fatigue, and maintain alignment between policy, regulation and implementation.

In this regard, growth in demand-side flexibility is better understood as a societal transformation requiring coordinated action across government, regulators, system operators and industry, rather than solely a regulatory initiative. Accordingly, its long-term success is dependent upon collaborative governance arrangements extending beyond the energy sector and beyond CRU’s remit. The CRU therefore considers that any NEDS follow-on programme would likely be most effective if taken forward through a Government-led governance structure. This would allow the future programme to address the wider policy levers that sit outside the regulatory sphere, require coordination across Government, agencies, system operators and industry, and cannot be delivered through regulatory mechanisms alone.

Appendix

A. Estimation of flexibility as part of NEDS Decision

The NEDS Decision paper (CRU202467) included an estimate of the demand-side flexibility volume that could be shifted within a day by 2030. The graph displayed in Figure 7 shows the contribution of flexibility areas to the total flexibility volume from 2024 to 2030. Compared to the 2030 CAP target of 20-30%, based on the current projections, the estimated demand-side flexibility is expected to reach 25%, with a significant contribution from EirGrid's planned flexibility procurement of energy storage and flexibility from residential EV and smart appliances.

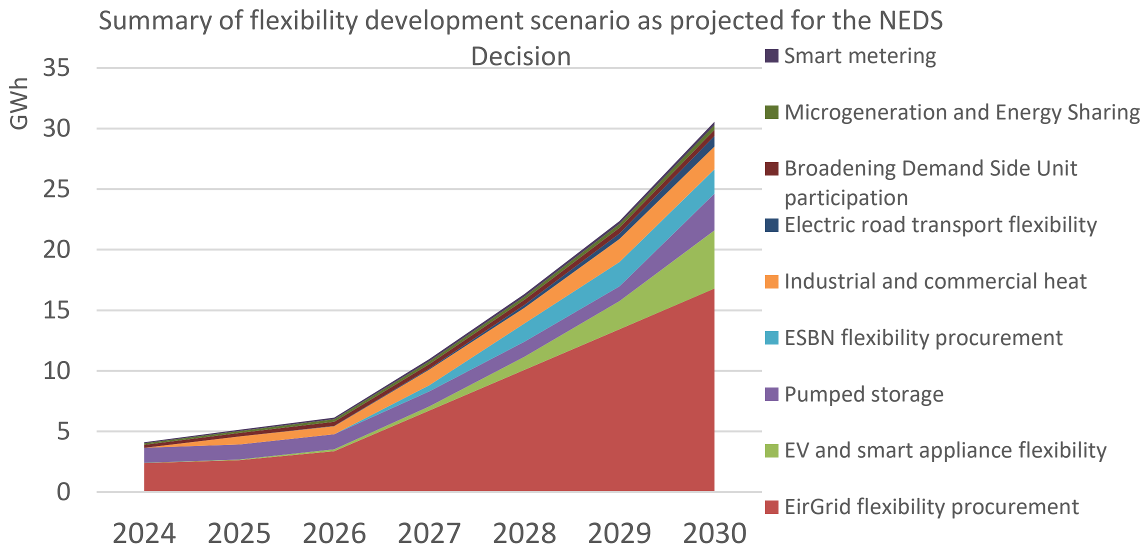


Figure 7: Projection of flexibility from a selected sources for NEDS Decision paper (2024).

The methodology for estimating flexibility volume was split into two primary mechanisms for flexibility: implicit and explicit, which align with the two NEDS areas, Smart Services and Demand Flexibility & Response, respectively. The third area of NEDS, New Demand Connections, is linked to flexibility from LEUs and GEPs.

Flexibility from LEUs and GEPs was not included in the estimation of their contribution to system flexibility, as it was still being developed at the time of the NEDS Decision publication. The development of a LEU Connections Policy has subsequently been concluded by the CRU, with the relevant decision having been published in December 2025[19]. Further work on planning and development of the GEPs has been undertaken by the LEAP.

B. Breakdown of Demand-side flexibility projections

A detailed breakdown of contributions to the demand-side flexibility volume by category type and flexibility source grouping is provided in Table 3 .

Table 3: Summary of turn-down volume for 2030 and 2035 per flexibility source categories into flexibility groupings and customer type.

Flexibility sources grouped by customer type and cohort from 2024 estimation for NEDS Decision	Turn-down volume (MWh)	
	2030	2035
Commercial	**3058.1**	**6242.9**
Industrial and commercial heat	**1909.2**	**3261.2**
District Heating	19.2	80.0
Heat	1890.0	3181.2
Broadening Demand Side Unit participation	**876.5**	**1493.5**
Demand Response	798.0	1260.0
Green energy park	78.5	233.5
Electric road transport flexibility	**267.0**	**1475.6**
BtM EV	38.9	916.6
BtM V2X	8.1	299.0
EV hubs	220.0	260.0
LEU and demand flexibility services - further procurement	**5.3**	**12.7**
LEUs	5.3	12.7
On-site generation and storage	**0.0**	**0.0**
BtM Generation	0.0	0.0
BtM Storage	0.0	0.0
Residential	**2477.6**	**6448.9**
Microgeneration and Energy Sharing	**1798.5**	**4689.1**
Energy Sharing	60.5	139.4
Generation	170.3	552.3
Storage	1567.7	3997.4
EV and smart appliance flexibility	**419.6**	**1356.8**
EV	42.8	79.4
Heat	264.6	721.8
V2X	112.3	555.6
Behavioural flexibility	**259.6**	**402.9**
Behavioural	259.6	402.9
Utility Scale	**7042.2**	**8272.5**
EirGrid flexibility procurement	**3634.5**	**4834.5**

[19] Review of Large Energy Users Connection Policy | CRU.ie

Energy Storage	3634.5	4834.5
Pumped storage	**1372.4**	**1372.4**
Pumped storage	1372.4	1372.4
ESBN flexibility procurement	**2000.0**	**2000.0**
ESBN procurement	2000.0	2000.0
Network flex	**35.3**	**65.6**
Network flex	35.3	65.6
Grand Total	**12577.9**	**20964.3**

C. Models for flexibility sources

The sections below describe the methodology, assumptions, and how scenarios apply to each flexibility source.

Table 4: List of flexibility models, their cohort used in the analysis, technology assumed in delivery of flexibility from the source and the confidence level in the forecasts to 2035.

Flexibility Source	Flexibility cohort	Included technology	Confidence level
Residential customers			
Behavioural	Behavioural flexibility	Smart meters and price signals driving change in behaviour	Low
Heat	EV and smart appliance flexibility	Demand response from heat pumps in response to price signals or aggregation	Medium
EV	EV and smart appliance flexibility	Smart EV charging in response to price signals or aggregation	Medium
V2X	EV and smart appliance flexibility	Bi-directional smart EV charging in response to price signals or aggregation	Low
Generation	Microgeneration and Energy Sharing	Demand response associated with solar PV generation	Low
Storage	Microgeneration and Energy Sharing	Battery energy storage paired with PV to maximise self-consumption or in response to price signals	Medium
Energy Sharing	Microgeneration and Energy Sharing	Change in demand to match local generation in response to aggregation or prices in a community energy zone	Low
Commercial and industrial customers			
Demand Response	Broadening Demand Side Unit participation	Medium to large industrial premises aggregated for participation in the capacity market.	High
Heat	Industrial and commercial heat	Industrial customers switching from electrode boilers to gas boilers and demand response from heat pumps in commercial properties in response to price signals or aggregation	Medium
EV	Electric road transport flexibility	Smart charging of light commercial vehicles, electric HGVs and buses in response to price signals or aggregation	Medium
V2X	Electric road transport flexibility	Bi-directional charging of light commercial vehicles, electric HGVs	Low

		and buses in response to price signals or aggregation.	
EV hubs	Electric road transport flexibility	Publicly available EV hubs with multiple high-powered chargers and variable pricing.	Medium
Storage	On-site generation and storage	Assumed to be part of DSU.	
Generation	On-site generation and storage		
Heat Networks	Industrial and commercial heat	District heating with thermal storage, gas-powered combined heat and power, and electrode boilers.	Low
Green energy park	Broadening Demand Side Unit participation	Mix of industrial and commercial demand co-located on a single site with renewable generation, storage and renewable energy sources.	Low
LEUs	Broadening Demand Side Unit participation	Stand-alone LEUs with BtM generation, storage and or demand flexibility.	Low
Utility-scale flexibility			
ESBN flexibility procurement		Energy storage and demand response procured by ESBN	High
EirGrid flexibility procurement		Battery energy storage procured through capacity market, DS3 System services and Long Duration Energy Storage auctions.	High
Network flex		Conservation Voltage Reduction to manage demand on the electricity distribution network.	Low
Pumped storage		Pumped hydro storage participates in electricity wholesale markets through daily charging and discharging cycles.	High

Residential flexibility from behavioural response to ToU

Residential Demand response is a flexibility mechanism driven by ToU tariffs with higher prices during the demand period, which incentivise shifting energy-intensive activities away from peak-demand periods to low-demand/high-generation periods. This type of flexibility is based on an implicit mechanism: price signals delivered to customers through ToU tariffs and compatible smart meters. Behavioural flexibility includes changes in residential demand, driven by practices and behaviours in response to price signals, such as static or dynamic ToU tariffs. It excludes automated responses from smart EV charging, energy storage, and connected smart appliances.

Relevant NEDS actions:

- (direct impact) 1.1 ToU tariffs (Retail suppliers – via CRU): Increase the number of permitted ToU tariffs offered and address barriers and incentives to increase uptake across customers.

- (direct impact) 1.2 Dynamic tariffs (Retail suppliers – via CRU): Develop and offer dynamic tariffs to customers following the decision requiring suppliers with more than 200,000 final customers to have dynamic tariffs in place.
- (direct impact) 1.6 Customer engagement for flexibility initiatives (SSWG): Develop, agree and publish plan for customer (residential & businesses) engagement to drive widespread awareness, consumer interest and desire to participate in flexibility initiatives.
- (direct impact) 1.9 Completion of smart meter rollout (ESBN): Smart meter upgrades to continue across remaining domestic customers including day/night meters. Complete rollout of smart meters for 3 Phase customers. Develop and adapt delivery to maximise the benefits of smart meters.

The methodology for estimating the demand response volume is based on the projection of the number of households that sign up to the peak-price ToU tariffs and the assumed response per household. For example, for the middle scenario in 2030, it is assumed that there will be approximately 2.24 million households, out of which 95% will have smart meters, of which 54% are on a ToU tariff with peak price period. Applying 0.23kWh of demand turn-down during evening peak period delivered by all households on ToU tariffs, gives a total response of 264MWh on an average day.

<table>
<tr><th colspan="2">Methodology:</th></tr>
<tr><td>Demand turn-down volume:
Number of households with smart meters and ToU *
Average daily demand turn-down (kWh)</td><td>Demand turn-up volume:
Number of households with smart meters and ToU *
Average daily demand turn-up (kWh)</td></tr>
<tr><th colspan="2">Assumptions</th></tr>
<tr><td colspan="2">• Residential Demand Side Response (DSR) to ToU (excluding EVs) from Crowd Flex[20] project (turn down: 0.23 kWh and turn up: 3kWh)
• Household growth based on 2022 census, then in line with macroeconomic growth per scenario as given in section 2.3
• Response to dynamic ToU and static peak-price ToU is equivalent
• Persistent behavioural response delivered in addition to other flexibility</td></tr>
<tr><th colspan="2">Limitations</th></tr>
<tr><td colspan="2">• Implicit flexibility (driven by price signals) assumes a persistent response, which acts as a deterrent from increasing peak demand (or peak generation) and cannot be “dispatched” or triggered to deal with short-term needs, i.e. excluding critical peak pricing.
• All households are assumed to be homogeneous, excluding distributional impacts and the abilities of households to participate in demand response. These differences are incorporated into the volume of flexibility delivered by participating households.</td></tr>
</table>

[20] CrowdFlex Phase 1 Trial report, https://www.neso.energy/document/230236/download

Several aspects influence how scenarios impact the inputs to the methodology:

<table>
<tr><th colspan="3">Scenarios</th></tr>
<tr><th colspan="2">Aspects that impact the volume</th><th>Potential impact on the forecast</th></tr>
<tr><td colspan="2">Availability and diversity of ToU with peak period pricing</td><td>Participation rate (%)</td></tr>
<tr><td colspan="2">Consumer education on ToU and its benefits</td><td>Participation rate (%)</td></tr>
<tr><td colspan="2">Standards for integration ToU with appliances</td><td>Response magnitude (kW) and duration (hrs)</td></tr>
<tr><td colspan="2">Communication and engagement with consumers</td><td>Response magnitude (kW) and duration (hrs)</td></tr>
<tr><th>Scenario</th><th>Scenario assumptions</th><th>Impact</th></tr>
<tr><td>Delayed Delivery (DD, low)</td><td>The majority of ToU tariffs are two-level flat tariffs (day/night), up to 8 peak-price ToU tariffs from a few suppliers. Early adopters are the primary customer segment adopting peak-price ToU tariffs. A good level of digital literacy is required to understand the benefits of time-of-use tariffs and effectively participate in behavioural flexibility.</td><td>2.13 million households by 2030

25% Participation rate from 95% of smart meter uptake by 2030

0.15 kWh average demand turn-down response per household

2.25 kWh average demand turn-up response per household</td></tr>
<tr><td>Expected Delivery (ED, mid)</td><td>Most ToU tariffs are peak-price ToU tariffs. Most of the retail suppliers offer at least one peak-price ToU tariff. An average consumer can access the ToU tariff and the associated benefits.</td><td>2.24 million households by 2030

54% ToU participation rate from 95% of smart meter uptake by 2030

0.23 kWh average demand turn-down response per household

3 kWh average demand turn-up response per household</td></tr>
<tr><td>Enhanced Growth (EG, high)</td><td>ToU tariffs are primarily peak-price ToU tariffs. All retail suppliers offer at least one peak-price ToU tariff. Most consumers can access the ToU tariffs, understand the associated benefits and can adjust their consumption with ease. Government support is available to vulnerable customers to address fairness and equity challenges. National communication campaign to provide information on ToU tariffs and advice on how to maximise cost reduction from ToU.</td><td>2.8million households by 2030

65% ToU participation rate from 95% of smart meter uptake by 2030by 2030

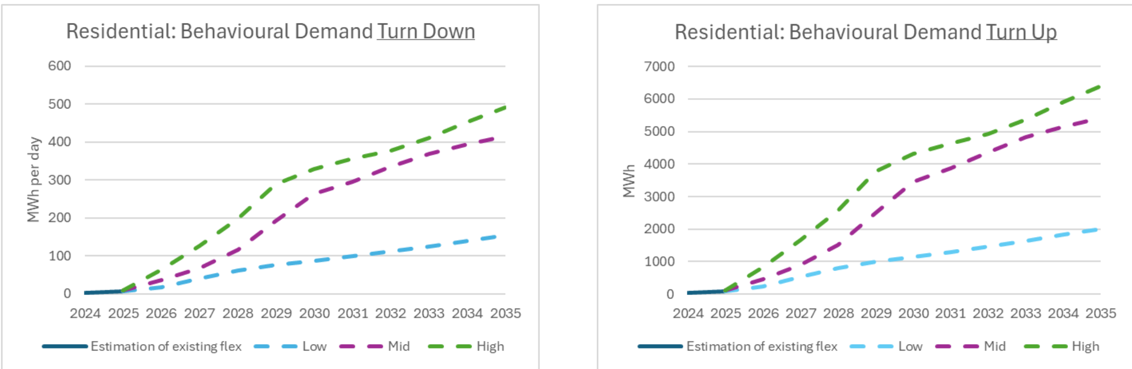
0.25 kWh average demand turn-down response per household;

3.3 kWh average demand turn-up response per household;</td></tr>
</table>

The methodology and the assumptions produced are applied to the following projects for the key years and projection over time in Figure 8:

Projections				
Decision paper projection	2030	Scenario	2030	2035
Turn down flexibility	270 MWh (0.22%)	DD, low	87 MWh (0.08%)	153 MWh (0.13%)
		ED, mid	264 MWh (0.21%)	415 MWh (0.3%)
		EG, high	329 MWh (0.24%)	491 MWh (0.32%)
Turn up flexibility	270 MWh (0.22%)	DD, low	1141 MWh (1.1%)	2005 MWh (1.7%)
		ED, mid	3452 MWh (2.8%)	5425 MWh (3.9%)
		EG, high	4302 MWh (3.2%)	6405 MWh (4.2%)

Trajectories or demand turn-down and demand turn-up



a b

Figure 8 Projections of flexible volume from residential behavioural demand response for (a) turn down and (b) turn up.

Residential flexibility from heat

This form of demand response arises from modifying the schedule for heating and hot water from residential heat pumps and relying on integrated thermal storage of building fabric to maintain indoor temperature. Demand turn-up is delivered by running a hot-water cycle or boosting heating.

This type of flexibility can be:

- explicit with direct control by an aggregator, retail supplier or network operator (e.g. in case of emergency) or
- implicitly flexible by optimising power consumption in response to price signals via time of use tariffs.

This flexibility includes demand response from heat pumps and storage heaters or thermal properties of the building fabric and excludes hybrid heating and energy vector switching flexibility.

Relevant NEDS actions:

- (direct impact) 1.17 Energy smart appliances, (SSWG): Publish review of options for development of standards to enable the uptake of “energy smart” appliances.
- (enabling/indirect impact) 1.12 Market design changes for secondary measurement devices (CRU): Consultation to establish what market design changes will be required for secondary measurement devices, and the timelines for implementing those changes.
- (enabling/indirect impact) 1.13 Licences for aggregation and demand response (CRU): Consult on development of new licences for aggregation and demand response.

The methodology for estimating the demand response volume is based on the projection of the number of heat pumps with the capability to be flexible, the participation rate by the households to deliver flexibility from heat, the assumed peak time power consumption and the duration for which the heat-up can operate flexibly.

Methodology:	
Demand turn-down volume: Number of households with heat pumps * DSR participation rate (%) * After Diversity Maximum Demand (ADMD) contribution from heat pump (kW) * Duration of response (hrs).	**Demand turn-up volume**: Number of households with heat pumps * DSR participation rate (%) * Demand during hot water cycle (kW) * Duration (hrs)
Assumptions	
• Uptake of heat pumps based on a proportion of households as projected in the behavioural flexibility • ADMD of 2kW on review of heat pump trials[21]	
Limitations	
• All households are assumed to be homogeneous without distinguishing the heating needs or thermal store capacity across the housing stock. • Demand turn-up does not account for the impact on the local distribution networks and the limitation on the permitted response due to constraints • Not considering retrofitting smart controls or interface compatibility with the heat pump or thermal store manufacturers.	

Several aspects influence how scenarios impact the inputs to the methodology:

Scenarios	
Aspects that impact the volume	**Potential impact on the forecast**
Supply chain, installer availability, and install quality	Number of heat pumps

[21] Jenny Love et al, *The addition of heat pump electricity load profiles to GB electricity demand: Evidence from a heat pump field trial*, Applied Energy, Volume 204, 2017, Pages 332-342, ISSN 0306-2619, https://doi.org/10.1016/j.apenergy.2017.07.026.

Ease of enabling and controlling heat pumps and storage heaters (as an entry barrier for consumers) (Direct link to Actions 1.12, 1.13)	DSR participation rate (%)
Housing stock quality and energy efficiency (BER rating)	Response magnitude (kW) and duration (hrs)
Standards, automation, and control of flexible heat (1.17, 1.12)	Response magnitude and duration
Communication and engagement with consumers	Response magnitude and duration

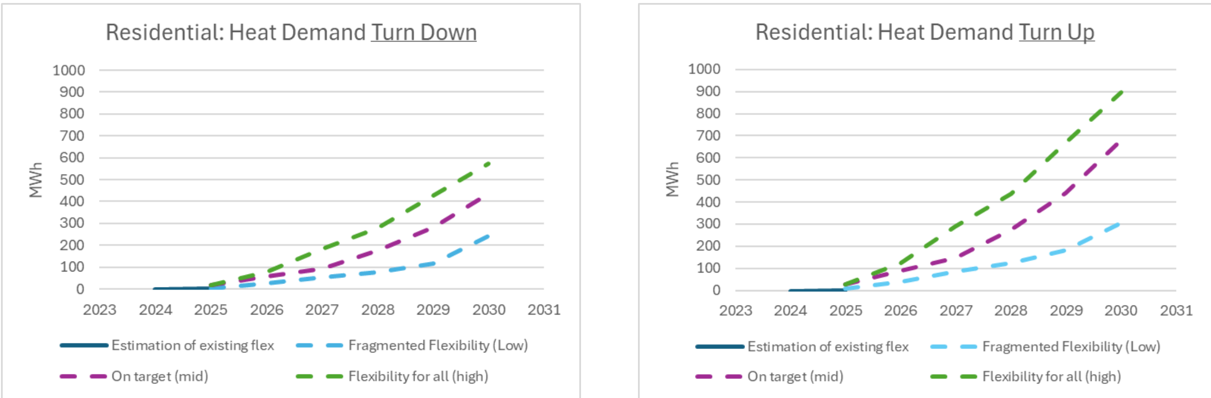
Scenario	Scenario assumptions	Impact
Delayed Delivery (DD, low)	Early adopters are the primary customer segment to engage with smart heat pumps (and thermal storage). Lower-efficiency housing stock and lower coefficient of performance means higher peak-period energy demand and shorter demand turn-down duration. Manual controls lead to a lower participation rate for demand turn-up.	19% of households with heat pumps and flex participation of 15% by 2030; 2.3 kW average demand turn-down response over an hour per household; 4 kWh average demand turn-up response over an hour per household
Expected Delivery (ED, mid)	Early majority are the primary customer segment to engage with smart heat pumps (and thermal storage). Improved energy efficiency reduces the peak-period energy demand and increases the duration of demand turn-down. Some retail suppliers offer heating bundles to increase the number of smart heat pumps and a higher participation rate in flexibility through connected appliances.	19% of households with heat pumps and a participation rate of 19% by 2030; 1.7 kWh average demand turn-down response over just under 90 mins per household; 3 kWh average demand turn-up response over an hour per household;
Enhanced Growth (EG, high)	Early majority are the primary customer segment to engage with smart heat pumps (and thermal storage). Further improved on energy efficiency. Retail suppliers offer heating bundles with smart functionality.	24% of households with heat pumps and a participation rate of 30% by 2030; 1.5 kWh average demand turn-down response over just over 90 mins per household; 3 kWh average demand turn-up response over an hour per household;

The methodology and the assumptions produced are applied to the following projects for the key years and projection over time:

Projections				
Decision paper projection	2030	Scenario	2030	2035
Turn down flexibility	92 MWh (0.06%)	DD, low	157 MWh (0.15%)	469 MWh (0.4 %)
		ED, mid	264 MWh (0.22%)	721 MWh (0.52 %)

		EG, high	416 MWh (0.31%)	1279 MWh (0.86%)
Turn up flexibility	92 MWh (0.06%)	DD, low	652 MWh (0.05%)	2006 MWh (1.4 %)
		ED, mid	415 MWh (0.3%)	1132 MWh (0.8 %)
		EG, high	247 MWh (0.23%)	736 MWh (0.6 %)

Trajectories or demand turn-down and demand turn-up



a b

Figure 9 Projections of flexible volume from residential flexibility from heat for (a) turn down and (b) turn up.

Residential flexibility from generation

Demand turn-down response from residential generation assumes flexibility from occupants, who adjust their use to align some flexible demand (e.g., dishwasher or washing machine) with periods of high residential rooftop PV generation, which otherwise would be run during evening peak periods. Demand turn-up is assumed to be infrequent and only required during high network stress or extreme network-needs events and achieved by remotely controlling PV inverters to reduce their output during periods of high generation. The likelihood of triggering such curtailment would be reduced by other demand-side flexibility resources that can increase demand, e.g., energy storage, EV flexibility, and energy sharing, and therefore, renewable generation would continue to deliver clean power.

Relevant NEDS actions:

- (direct impact) 1.16 'Flexibility readiness' requirements (ESBN): Introduce technical requirements for interoperable telecommunications and control facilities for inverter-interfaced small-scale solar PV and battery sources.
- (enabling/indirect impact) 1.11 Microgeneration operational issues (ESBN): Review the impact of operational challenges for SOs associated with high levels of microgeneration, given the potential growth of installations, and report to the CRU.
- (enabling/indirect impact) 1.12 Market design changes for secondary measurement devices (CRU): Consultation to establish what market design changes will be required for secondary measurement devices, and the timelines for implementing those changes.

- (enabling/indirect impact) 1.13 Licences for aggregation and demand response (CRU): Consult on development of new licences for aggregation and demand response.
- (enabling/indirect impact) 1.15 Energy sharing and trading (CRU): Publish call for evidence in relation to energy sharing to identify and develop opportunities to support producers and consumers to share their generated electricity and incentivise flexibility.

The methodology for estimating demand response volume is based on projections of the number of residential PV installations and the percentage behavioural self-consumption participation for demand turn-down, and uptake of inverters compatible with remote control functionality.

Methodology:	
Demand turn-down volume: Number of households * % with PV installations (%) * Manual self-consumption practice rate (%) * Shiftable daily energy (kWh)	**Demand turn-up volume**: Number of households * % with PV installations (%) * average installed capacity (kWp) * Response duration (hrs) * Remote control functionality rollout (%)
Assumptions	
• Based on a proportion of households as projected in the behavioural flexibility, starting with 9% uptake based on 2022 census. • Average size of rooftop PV installation is 3.7kWp • Shiftable daily energy consumption of 1.2kWh (e.g. from dishwasher or laundry) • For demand turn-up, assume remote capability for switching of the inverters for an hour during peak-generation periods.	
Limitations	
• All PV installations are assumed to be homogeneous (all households have the PV installation of the same capacity and configuration) • Consumers have visibility of output from the PV and can start appliances for the period of peak PV generation • PV inverters with remote control functionality are available and respond when required. • Consumers with PV inverters give consent for remote control of their inverters	

Several aspects influence how scenarios impact the inputs to the methodology:

Aspects that impact the volume	Potential impact on the forecast
Availability and effectiveness of grants for PV	% of households with PV installations
Cost of PV panels	% of households with PV installations
Consumer education and awareness of benefits	Self-consumption participation rate (%)
Standardisation of interfaces and inverter OEM engagement	Remote control functionality rollout (%)
Incentives and realisation of benefits for SOs to develop capability	Remote control functionality rollout (%)
Scale of network monitoring and visibility of constraints	Remote control functionality rollout (%)

Scenario	Scenario assumptions	Impact

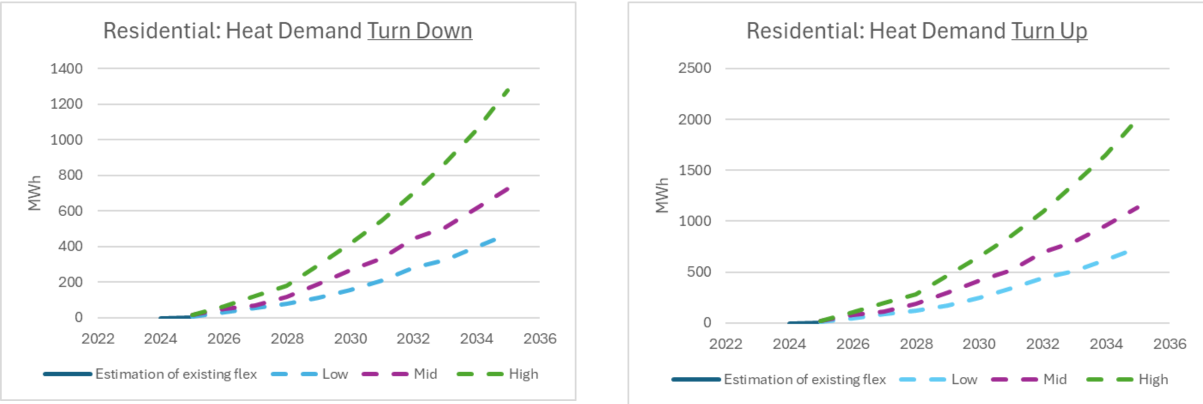
Delayed Delivery (DD, low)	Maintaining the current trajectory on the uptake of PV as a proportion of households. Variations in supplier export rates reduce clarity on payback. Frequent grant tweaks and uncertainty about grant changes prevent households from committing. Installer bottleneck and grid constraints delay new connections.	24% of households with PV installed by 2030 and 18% of households with PVs are shifting energy use to match peak generation. 0.9 kWh average demand turn-down response by shifting load away from peak demand. 2.78 kWh average demand turn-up response from curtailment at peak generation.
Expected Delivery (ED, mid)	Grants remain predictable and bring confidence to the customers. Steady growth in installer capacity and supply chain results in faster-than-current update trajectories and participation rates. Greater awareness of the benefits of self-consumption and retail product innovation leads to a greater willingness to act increase the participation rate.	31% of households with PV installed by 2030 and 30% of households with PVs are shifting energy use to match peak generation. 1.2 kWh average demand turn-down response by shifting load away from peak demand. 3.7 kWh average demand turn-up response from curtailment at peak generation.
Enhanced Growth (EG, high)	Early acceleration in the uptake of PVs, greater capacity enabled through further reduction in costs (direct and through subsidies), attractive export and ToU tariff. Smooth installer experience and growth in one stop shop services.	33% of households with PV installed by 2030 and 43% of households with PVs are shifting energy use to match peak generation. 1.32 kWh average demand turn-down response by shifting load away from peak demand. 3.7 kWh average demand turn-up response from curtailment at peak generation.

The methodology and the assumptions produced are applied to the following projects for the key years and projection over time in:

Projections					
Decision paper projection		2030	Scenario	2030	2035
Turn down flexibility	Decision paper projection (2030)	400 MWh (0.33%)	DD, low	74 MWh (0.07%)	296 MWh (0.25 %)
			ED, mid	170 MWh (0.14%)	552 MWh (0.4 %)
			EG, high	318 MWh (0.24%)	920 MWh (0.62%)

Turn up flexibility	Decision paper projection (2030)	400 MWh (0.33%)	DD, low	266 MWh (0.25%)	1062 MWh (0.9 %)
			ED, mid	610 MWh (0.5%)	1979 MWh (1.4 %)
			EG, high	1036 MWh (0.8%)	3248 MWh (2.2%)

Trajectories or demand turn-down and demand turn-up



b

a

Figure 10 Projections of flexible volume from residential flexibility from PV generation for (a) turn down and (b) turn up.

Residential flexibility from V2X

Flexibility from Residential V2X charging is delivered by scheduling when EVs are charged and discharged in response to external signals, such as a control schedule from an aggregator or price signals, or by taking the household off grid by supplying it directly. **Includes**: Domestic V2H/V2G smart charging responding to time of use tariffs or through direct aggregation. **Excludes**: On-street charging and other public charging. Smart charging (V1G).

Relevant NEDS actions:

- (direct impact): 1.3 Smart EV charging services (ESBN): Engage across relevant parties to develop propositions for smart charging services, including an exploratory investigation of V2G services. Establish working group to explore barriers and enablers. Publish programme of work.
- (direct impact): 2.2 V2G charging point uptake (ESBN): Review how support for the increased uptake of V2G-enabled charging points can be implemented as part of the Electric Vehicle Charging Strategy 2026 – 2029 and reflect this updated strategy publication.
- (enabling/indirect impact) 1.11 Microgeneration operational issues (ESBN): Review impact of operational challenges for SOs associated with high levels of microgeneration given the potential growth of installations and report to the CRU.
- (enabling/indirect impact) 1.12 Market design changes for secondary measurement devices (CRU): Consultation to establish what market design changes will be required for secondary measurement devices, and the timelines for implementing those changes.

- (enabling/indirect impact) 1.13 Licences for aggregation and demand response (CRU): Consult on development of new licences for aggregation and demand response.
- (enabling/indirect impact) 2.13 Smart charging flexibility product (ESBN): Develop and launch new smart charging flexibility product and/or service and ensure the delivery is fair and effective in enabling demand flexibility through EVs
- (enabling/indirect impact) 2.16 Optimise EV fleet charging (ESBN): Develop and publish plan to optimise EV fleet charging through technology and software solutions.
- (enabling/indirect impact) 2.17 Smart EV charging availability (EBSN): Develop and publish technical assessment of how the available smart EV charging and V2G capacity can be maximised through network operations.

The methodology for estimating demand response volume is based on projections of the number of residential EV V2G smart charger installations, typical response capacity per charger and the duration of response.

<table>
<tr><th colspan="2">Methodology:</th></tr>
<tr><td>Demand turn-down volume:
Number domestic V2G charger units*
Turn down capacity (kW)*
Response duration (hr) *
Participation rate (%).</td><td>Demand turn-up volume:
Number domestic V2G charger units*
Turn down capacity (kW)*
Response duration (hr) *
Participation rate (%).</td></tr>
<tr><th colspan="2">Assumptions</th></tr>
<tr><td colspan="2">• Vehicles with V2G do not participate in unidirectional smart charging
• Nominal daily charge/discharge cycle of 50% of a 60kWh battery between 20% and 80% SoC and adjusted per scenario to represent variation in EV usage.
• Nominal ratings are 6 kW export[22] and 6 kW import.
• Participation and availability rate assumed at 60% based on charge availability and connection likelihood.[23]
• 10-20%[24] of EV are compatible with V2X[25] by 2030</td></tr>
<tr><th colspan="2">Limitations</th></tr>
<tr><td colspan="2">• All V2G smart charging installations and the compatible EVs are assumed to have homogeneous behaviour and requirements. Averages across vehicle types and usage patterns are used in the estimation.
• Availability of EVs and likelihood of user overriding schedule is incorporated on the participation rate</td></tr>
</table>

[22] V2G is treated as a microgenerator and limited to 25Amp per phase as per Conditions Governing the Connection and Operation of Micro-Generation

[23] World's largest domestic Vehicle-to-Grid trial reveals customers could recover the majority of their household energy costs - OVO Group

[24] UK Market Projection by 2030. Everything You Need to Know About Vehicle-to-Grid (V2G) in the UK | The Electric Car Scheme

[25] Based on the models from VW group (Cleverly manage your own electricity: First ID. models support bidirectional charging | Volkswagen Newsroom), Kia EV9, EV6, Ionic 5 (Hyundai Motor Group Expands EV Energy Services with Vehicle to Grid and Vehicle to Home, Volvo Ex90 Volvo EX90 customers can now send power back to their homes with bi-directional charging | Volvo Cars Media US

Several aspects influence how scenarios impact the inputs to the methodology:

Scenarios	
Aspects that impact the volume	**Potential impact on the forecast**
Availability and affordability of V2G-compatible chargers	Number of domestic V2G charger units
Availability and affordability of V2G-compatible EVs.	Number of domestic V2G charger units
	Turn down capacity (kW)
	Response duration (hr)
	Participation rate (%)

Scenario	Scenario assumptions	Impact
Delayed Delivery (DD, low)	Delay in availability of compatible chargers and EVs. High cost of V2G chargers and lack of appropriate grants. Delay in rollout of local smart flexibility services and availability of suitable ToU tariffs. Most consumers are not familiar with V2G features and their benefits.	By 2030, 2% of households with EV chargers are V2G, and 60% of these enabled and available. The average discharge rate is 4.5kW for 3.75 hours. The average charge rate is 4.5kW for 3.75 hours.
Expected Delivery (ED, mid)	Better uptake and participation rate. Better integration of chargers to enable flexibility. Grants remain predictable and bring confidence to the customers. Growth and visibility of local flexibility products attract more EV-based flexibility. Suppliers offer more V2G-focused products and tariffs. Alignment in standards and wider coordination increases the number of V2G compatible EV models.	By 2030, 3% of households with EV chargers are V2G, and 70% of these are enabled and available The average discharging rate is 6kW for 6 hours. The average charge rate is 6kW for 6 hours
Enhanced Growth (EG, high)	Early acceleration in the uptake of chargers, and a greater participation rate. Consumers have access to end-to-end EV propositions, including V2G-compatible options, simplifying EV access and enabling flexibility.	By 2030, 6% of households with EV chargers are V2G, and 80% of these are enabled and available The average discharging rate is 6kW for 6 hours. The average charge rate is 6kW for 6 hours.

The methodology and the assumptions produced are applied to the following projects for the key years and projection over time:

Projections				
Decision paper projection	**2030**	**Scenario**	**2030**	**2035**

Turn down flexibility	3380MWh (2.75%)	DD, low	31MWh (0.03%)	212 MWh (0.18 %)
		ED, mid	112.2MWh (0.09%)	552 MWh (0.4 %)
		EG, high	469MWh (0.35%)	2647 MWh (1.79 %)
Turn up flexibility	3380MWh (2.75%)	DD, low	31 MWh (0.03%)	212 MWh (0.2 %)
		ED, mid	112 MWh (0.1%)	555 MWh (0.4 %)
		EG, high	469MWh (0.04%)	2647 MWh (1.8 %)

Trajectories or demand turn-down and demand turn-up

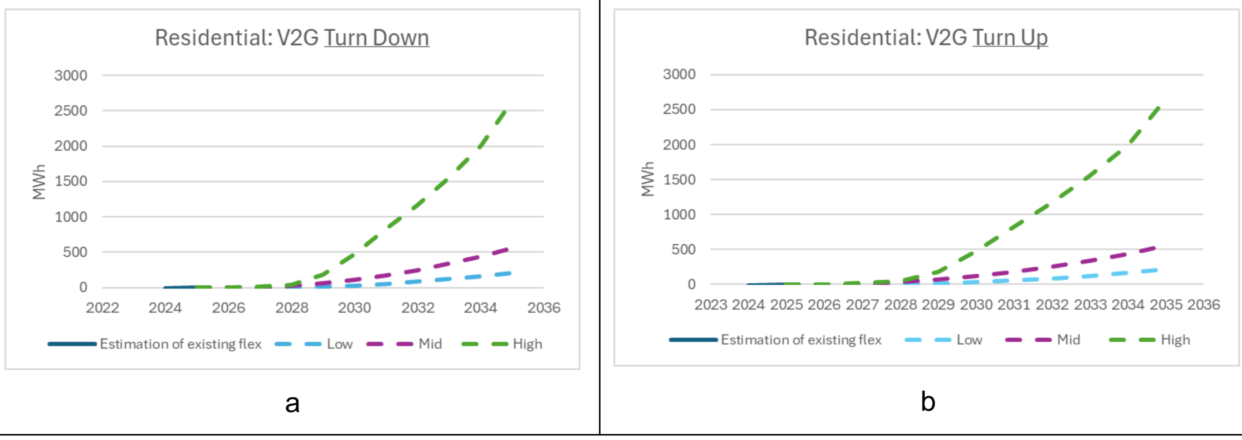


Figure 11 Projections of flexible volume from residential flexibility from V2G charging for (a) turn down and (b) turn up.

Residential flexibility from battery energy storage

Flexibility from the Residential battery energy storage is delivered by maximising self-consumption with the PV installation at the same property. Demand turn-down and demand turn-up are achieved by maximising self-consumption from PV and reducing the evening peak demand. **Includes:** Battery energy storage paired with PV. **Excludes:** Standalone energy storage without PV (due to limited availability of data and generally

Relevant NEDS actions:

- (enabling/indirect impact) 1.11 Microgeneration operational issues (ESBN): Review impact of operational challenges for SOs associated with high levels of microgeneration given the potential growth of installations and report to the CRU.
- (enabling/indirect impact) 1.12 Market design changes for secondary measurement devices (CRU): Consultation to establish what market design changes will be required for secondary measurement devices, and the timelines for implementing those changes.
- (enabling/indirect impact) 1.13 Licences for aggregation and demand response (CRU): Consult on development of new licences for aggregation and demand response.

- (enabling/indirect impact) 1.15 Energy sharing and trading (CRU) Publish call for evidence in relation to energy sharing to identify and develop opportunities to support producers and consumers to share their generated electricity and incentivise flexibility.

The methodology for estimating demand response volume is based on projections of the number of residential PV installation, proportion of PV installations paired with energy storage device and rating of the energy storage.

<table>
<tr><th colspan="2">Methodology:</th></tr>
<tr><td>Demand turn-down volume:
Number of households with PV installations *
Storage attachment rate *
Export rating *
export duration</td><td>Demand turn-up volume:
Number of households with PV installations *
Storage attachment rate *
Import rating *
Import duration</td></tr>
<tr><th colspan="2">Assumptions</th></tr>
<tr><td colspan="2">• Based on a proportion of households as projected in the behavioural flexibility, with PV uptake starting at 9% uptake based on 2022 census.
• Assuming a daily cycle of 80% of battery, charge at 5kW and discharge at 5kW, battery size 6kWh</td></tr>
<tr><th colspan="2">Limitations</th></tr>
<tr><td colspan="2">• All PV installations are assumed to be homogeneous (all households have the PV installation of the same capacity and configuration)
• Consumers have visibility of output from the PV and can start appliances for the period of peak PV generation
• Energy storage is used to maximise self-consumption.</td></tr>
</table>

Several aspects influence how scenarios impact the inputs to the methodology:

<table>
<tr><th colspan="3">Scenarios</th></tr>
<tr><th colspan="2">Aspects that impact the volume</th><th>Potential impact on the forecast</th></tr>
<tr><td colspan="2">Stability of grants, wider economic conditions, and planning requirements for PV and storage</td><td>Number of households with PV installations</td></tr>
<tr><td colspan="2">Cost of storage and supply chain availability</td><td>Storage attachment rate</td></tr>
<tr><td colspan="2">Cost of storage and network constraints</td><td>Export rating</td></tr>
<tr><td colspan="2">Cost of storage and available configurations</td><td>Export duration</td></tr>
<tr><th>Scenario</th><th>Scenario assumptions</th><th>Impact</th></tr>
<tr><td>Delayed Delivery (DD, low)</td><td>Maintaining trajectory, lower number of PVs, lower number of battery units. (1hr duration) 33% attachment rate for new installs</td><td>By 2030, 102k energy storage units will be installed alongside PV

Average rating of 3.75 kW for 1 hour</td></tr>
<tr><td>Expected Delivery (ED, mid)</td><td>Accelerated uptake and participation rate. Better customer proposition and battery size (2hr duration). 50% of new PV installations have storage.</td><td>By 2030, 156k energy storage units will be installed alongside PV

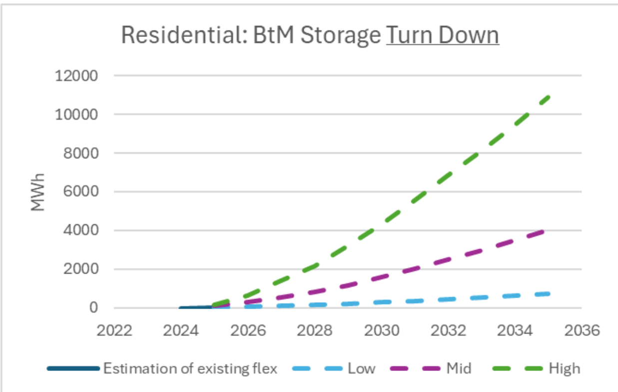
Average rating of 5 kW for 2 hours</td></tr>
</table>

Enhanced Growth (EG, high)	Early acceleration in the uptake of PVs, greater capacity and a greater number of batteries of larger capacity (3hr duration). 65% of new installations.	By 2030, 238k energy storage units will be installed alongside PV Average rating of 5.5 kW for 3 hours

The methodology and the assumptions produced are applied to the following projects for the key years and projection over time:

Projections				
Decision paper projection	**2030**	**Scenario**	**2030**	**2035**
Turn down flexibility	-	DD, low	288 MWh (0.26%)	710 MWh (0.61%)
		ED, mid	1568 MWh (1.28%)	3997 MWh (2.97 %)
		EG, high	4326MWh (3.25%)	10877 MWh (7.37%)
Turn up flexibility	-	DD, low	288 MWh (0.26%)	710 MWh (0.61%)
		ED, mid	1568 MWh (1.28%)	3997 MWh (2.97 %)
		EG, high	4326MWh (3.25%)	10877 MWh (7.37%)

Trajectories or demand turn-down and demand turn-up



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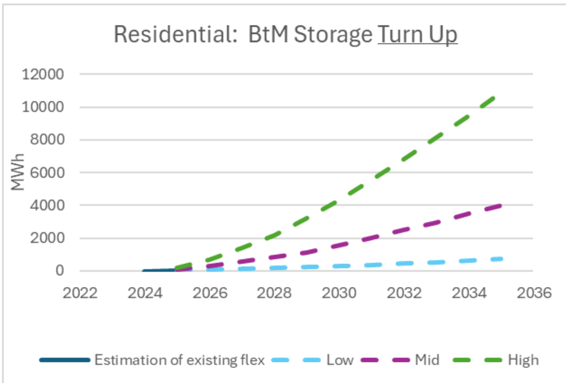

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Figure 12 Projections of flexible volume from residential flexibility from energy storage paired with PV

Residential flexibility from smart EV charging

Flexibility from the Residential Smart EV charging is delivered by scheduling when EVs are charging in response to external signals, such as a control schedule from an aggregator or price signals. **Includes:** Domestic smart charging responding to ToU tariffs or through direct aggregation. **Excludes:** On-street charging and other public charging.

Relevant NEDS actions:

- (direct impact): 1.3 Smart EV charging services (ESBN): Engage across relevant parties to develop propositions for smart charging services, including an exploratory investigation of V2G services. Establish working group to explore barriers and enablers. Publish programme of work.
- (enabling/indirect impact) 1.11 Microgeneration operational issues (ESBN): Review impact of operational challenges for SOs associated with high levels of microgeneration given the potential growth of installations and report to the CRU.
- (enabling/indirect impact) 1.12 Market design changes for secondary measurement devices (CRU): Consultation to establish what market design changes will be required for secondary measurement devices, and the timelines for implementing those changes.
- (enabling/indirect impact) 1.13 Licences for aggregation and demand response (CRU): Consult on development of new licences for aggregation and demand response.
- (enabling/indirect impact) 2.13 Smart charging flexibility product (ESBN): Develop and launch new smart charging flexibility product and/or service and ensure the delivery is fair and effective in enabling demand flexibility through EVs.
- (enabling/indirect impact) 2.16 Optimise EV fleet charging (ESBN): Develop and publish plan to optimise EV fleet charging through technology and software solutions.
- (enabling/indirect impact) 2.17 Smart EV charging availability (EBSN): Develop and publish technical assessment of how the available smart EV charging and V2G capacity can be maximised through network operations.

The methodology for estimating demand response volume is based on projections of the number of residential EV smart charger installations, typical response capacity per charger and the duration of response.

Methodology:	
Demand turn-down volume: Number domestic EV charger units* Turn down capacity (kW) * Response duration (hr) * Participation rate (%).	**Demand turn-up volume**: Number domestic EV charger units* Turn down capacity (kW)* Response duration (hr) * Participation rate (%).
Assumptions	
• Uptake of EV chargers is based on a proportion of households as projected in the behavioural flexibility • EV flexibility from Crowd Flex project (down: 0.2 kWh / up: 5.8kWh) and adjusted per scenario • Fixed participation rate of 40% for the middle scenario	
Limitations	
• All EV smart charging installations and EVs are assumed to have homogeneous behaviour and requirements. Averages across vehicle types and usage patterns are used in the estimation.	

Several aspects influence how scenarios impact the inputs to the methodology:

Scenarios

Aspects that impact the volume	Potential impact on the forecast
Availability of grants, installers and wider market conditions	Number of domestic EV charger units
Customer familiarity and education	Participation rate (%)
Number of enabled and smart chargers	Turn down capacity (kW)
Frequency of override by customer and vehicle usage	Response duration (hrs)

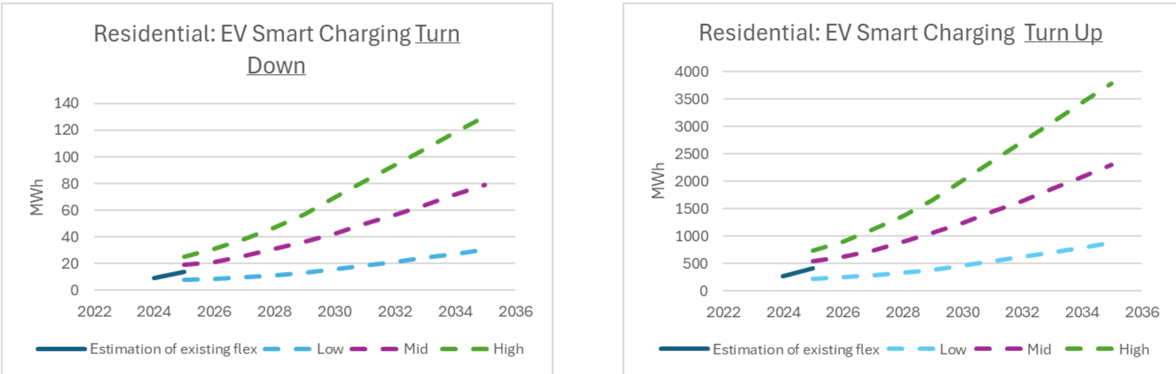
Scenario	Scenario assumptions	Impact
Delayed Delivery (DD, low)	Maintaining trajectory, fewer chargers, and lower response rates. Frequent grant tweaks and uncertainty about grant changes prevent households from committing. Delay in rollout of local smart flexibility services and availability of suitable ToU tariffs. Most consumers are not familiar with smart features and their benefits.	By 2030, 7.3% of households have EV chargers, and 30% of these chargers are smart and enabled. The average peak time charging rate is 0.18kW for 3 hours
Expected Delivery (ED, mid)	Accelerated uptake and participation rate. Better integration of chargers to enable flexibility. Grants remain predictable and bring confidence to the customers. Growth and visibility of local flexibility products attract more EV-based flexibility. Suppliers offer more EV-focused products and tariffs.	By 2030, 8.1% of households will have EV chargers, and 40% of these chargers will be smart and enabled. The average peak time charging rate is 0.2kW for 3 hours
Enhanced Growth (EG, high)	Early acceleration in the uptake of chargers, and a greater participation rate. Consumers have access to end-to-end propositions for EVs, simplifying access to EVs and enabling flexibility. A greater number of smart EV charges due to a smoother installation and connection process. Majority of the installed chargers are smart-ready.	By 2030, 9.7% of households will have EV chargers, and 44% of these chargers will be smart and enabled. The average peak time charging rate is 0.25kW for 3 hours

The methodology and the assumptions produced are applied to the following projects for the key years and projection over time:

Projections				
Decision paper projection	**2030**	**Scenario**	**2030**	**2035**
Turn down flexibility	1320 MWh (1.07%)	DD, low	15MWh (0.01%)	30 MWh (0.03 %)
		ED, mid	42.7MWh (0.03%)	79 MWh (0.06 %)
		EG, high	69.5MWh (0.05%)	130 MWh (0.09%)

Turn up flexibility	1320 MWh (1.07%)	DD, low	458MWh (0.43%)	881 MWh (0.8 %)
		ED, mid	1240MWh (1%)	2301 MWh (1.7 %)
		EG, high	2015 MWh (1.5%)	3785 MWh (2.6 %)

Trajectories or demand turn-down and demand turn-up



a b

Figure 13 Projections of flexible volume from residential flexibility from smart EV charging for (a) turn down and (b) turn up.

Residential flexibility from energy sharing

Flexibility from the participation of customers in local energy sharing schemes where customers can trade directly with local generation via local time of use tariffs which reduces the costs but also motivates behavioural shift in energy use. **Includes**: Change in demand to match local generation within the energy-sharing zone. **Excludes**: Smart EV charging, energy storage, and smart appliances.

Relevant NEDS actions:

- (direct impact): 1.15 Energy sharing and trading (CRU): Publish call for evidence in relation to energy sharing to identify and develop opportunities to support producers and consumers to share their generated electricity and incentivise flexibility.
- (enabling/indirect impact) 1.11 Microgeneration operational issues (ESBN): Review the impact of operational challenges for SOs associated with high levels of microgeneration given the potential growth of installations and report to the CRU
- (enabling/indirect impact) 1.12 Market design changes for secondary measurement devices (CRU): Consultation to establish what market design changes will be required for secondary measurement devices, and the timelines for implementing those changes.
- (enabling/indirect impact) 1.13 Licences for aggregation and demand response (CRU): Consult on development of new licences for aggregation and demand response.

The methodology for estimating demand response volume is based on projections of the proportion of households participating in energy sharing and their ability to deliver demand response during peak time or energy that can be shifted to follow available generation.

Methodology:	
Demand turn-down volume: Number of households * Participation rate in energy sharing (%) * Demand response capacity during peak time (kWh)	**Demand turn-up volume**: Number of households * Manual self-consumption practice rate (%) * Shiftable daily energy (kWh)

Assumptions
• Based on a proportion of households as projected in the behavioural flexibility, starting with 9% uptake based on the 2022 census. • Shiftable daily energy consumption of 1.2kWh (e.g. from dishwasher or laundry) to align with local generation • Appropriate incentives/price signals to motivate reliable and persistent response.

Limitations
• Energy sharing frameworks in Ireland remain at an early stage and require necessary commercial coordination mechanisms place to enable the participation. • The interaction between energy sharing and other flexibility sources (e.g., storage, smart charging) is not modelled.

Several aspects influence how scenarios impact the inputs to the methodology:

Scenarios		
Aspects that impact the volume		**Potential impact on the forecast**
Understanding of the benefits of energy sharing and suitable frameworks for participation.		Number of households
Understanding of the benefits from energy sharing and the ability to participate		Participation rate in energy sharing (%)
		Demand response capacity (kWh)
Scenario	**Description**	**Impact**
Delayed Delivery (DD, low)	Delay in planning and implementing energy sharing zones. Regulatory complexity is not resolved at scale. Enabling platforms remain fragmented, and the customer experience is inconsistent. Low support from retail suppliers. No growth beyond pilots.	By 2030, participating households will reach 42k Each delivers 0.8kWh of demand turn-down and 2 kWh demand turn-up
Expected Delivery (ED, mid)	Early pilots create a workable and scalable framework. Community renewables have a clearer path to implementation, enabled by community energy toolkits.	By 2030, participating households will reach 61k Each delivers 1.1 kWh of demand turn-down and 3 kWh demand turn-up
Enhanced Growth (EG, high)	Additional growth is supported by commercial and technical assistance frameworks. Retail suppliers have products designed for community energy. Easy-to-use and scalable platforms	By 2030, participating households will reach 68k Each delivers 2 kWh of demand turn-down and 4 kWh demand turn-up

	enable faster and lower-cost creation of energy sharing zones.	

The methodology and the assumptions produced are applied to the following projects for the key years and projection over time:

Projections				
Decision paper projection	**2030**	**Scenario**	**2030**	**2035**
Turn down flexibility	MWh (0.06%)	DD, low	35 MWh (0.03%)	84 MWh (0.07 %)
		ED, mid	60MWh (0.05%)	139 MWh (0.1 %)
		EG, high	148 MWh (0.11%)	364 MWh (0.25 %)
Turn up flexibility	MWh (0.06%)	DD, low	64MWh (0.06%)	153 MWh (0.1 %)
		ED, mid	181MWh (0.1%)	418 MWh (0.3%)
		EG, high	296MWh (0.02%)	728 MWh (0.5 %)

Trajectories or demand turn-down and demand turn-up

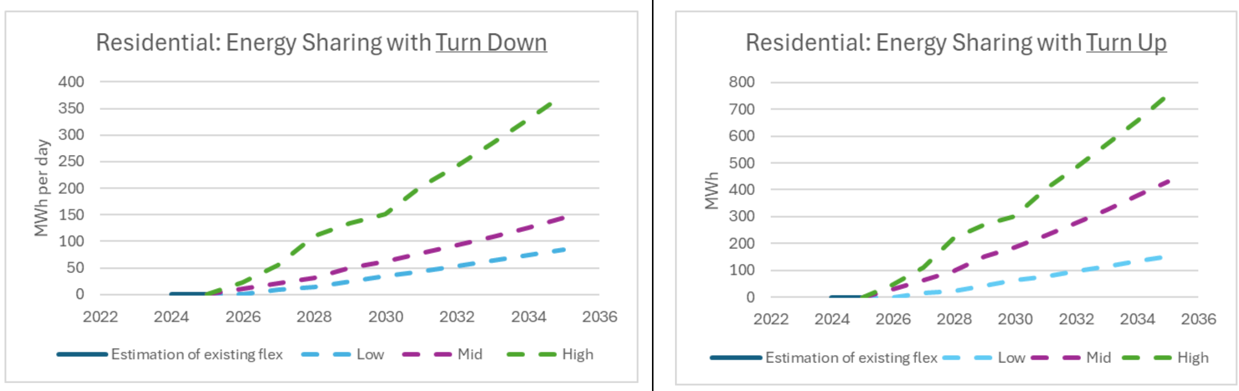


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Figure 14 Projections of flexible volume from residential flexibility from energy sharing for (a) turn down and (b) turn up.

Non-residential flexibility from demand side response

Flexibility from the commercial and industrial customers with flexible demand, behind-the-meter generation or storage that can be operated by aggregators to deliver services for EirGrid or ESBN. **Includes**: Change in business operations schedule (DSUs currently do not differentiate as long as it's behind the meter). **Excludes**: standalone BtM Storage, generation and EV/V2G on commercial properties.

Relevant NEDS actions:

- (direct impact) 2.3 Increase flexibility provided by DSUs (EirGrid): Develop and publish a plan of work to improve active participation and performance of DSUs in the market and remove barriers. Plan to clarify expectations on DSUs to increase the flexibility, consider industry-suggested code changes and describe technical updates to be implemented for TSO and MO systems.
- (direct impact) 2.4 Market changes to enable increased flexibility (EirGrid): Assess and report on status and potential solutions to enable energy market participants to offer increased flexibility through the energy market, supporting more flexible trading of demand, engaging suppliers more actively, and ensuring technology neutrality in market and dispatch systems.
- (direct impact) 2.6 TSO demand flexibility product (EirGrid): EirGrid to keep under review further potential options for TSO demand flexibility products, reporting output to CRU.
- (enabling/indirect impact) 2.19 Electricity system emissions information (EirGrid): Review approach to reporting of real time emissions from TSO dispatch of the system engaging with the CRU. Develop approach to integrate emissions data and reporting into wider TSO decision-making where it is possible to do so
- (enabling/indirect impact) 3.2: Enhanced quality and accessibility of network information (EirGrid): Enhance quality and accessibility of information relating to areas of the network, where capacity is available and future network development plans.

The methodology for estimating demand response volume is based on procured and projected available demand response capacity from I&C customers managed by aggregators to deliver contracted services. Aggregators schedule assets within a DSU to meet the requirements for duration and capacity.

Methodology:	
Demand turn-down volume: Estimated capacity * Duration of response * Unavailability rate.	**Demand turn-up volume**: Assumed not available
Assumptions	
• Up to 2027 DSR capacity based on contracted DSU[26] • 2030 targets based on EirGrid's SOEF1.1 projection of 1.2GW of DSU[27]	
Limitations	
• Not differentiating between what BtM source is used to deliver flexibility.	

[26] EirGrid's All-Island Resource Adequacy Assessment 2025-2034

[27] DSU capacity in Ireland by 2030, Shaping Our Electricity Future Roadmap: Version 1.1, 2023

Several aspects influence how scenarios impact the inputs to the methodology:

<table>
<tr><th colspan="3">Scenarios</th></tr>
<tr><th colspan="2">Aspects that impact the volume</th><th>Potential impact on the forecast</th></tr>
<tr><td colspan="2">New DSR flexibility products offer additional revenue streams</td><td>DSU capacity</td></tr>
<tr><td colspan="2" rowspan="2">Flexibility market development simplifies market access</td><td>DSU capacity</td></tr>
<tr><td>Duration of response</td></tr>
<tr><td colspan="2">Growth in DSR opportunities improves reliability</td><td>Unavailability rate</td></tr>
<tr><th>Scenario</th><th>Scenario assumptions</th><th>Impact</th></tr>
<tr><td>Delayed Delivery (DD, low)</td><td>Maintaining the current trajectory of procured DSU and a less reliable response due to fewer opportunities for DSR.</td><td>25% unavailability rate.
By 2030: 1300WM of DSU capacity with 2-hour duration and 2352MW by 2035</td></tr>
<tr><td>Expected Delivery (ED, mid)</td><td>Developing TSO demand flexibility products attracts more aggregators with DSUs. Better opportunities for DSUs reduce the unavailability rate.</td><td>20% unavailability rate.
By 2030: 1200WM of DSU capacity with 2-hour duration and 2129MW by 2035</td></tr>
<tr><td>Enhanced Growth (EG, high)</td><td>The development of TSO demand flexibility products and removing barriers to participation by simplifying the market access attracts more aggregators with DSUs and broader range of technologies within DSUs.</td><td>15% unavailability rate.
By 2030: 1300WM of DSU capacity with 2-hour duration and 2352MW by 2035</td></tr>
</table>

The methodology and the assumptions produced are applied to the following projects for the key years and projection over time:

<table>
<tr><th colspan="5">Projections</th></tr>
<tr><th>Decision paper projection</th><th>2030</th><th>Scenario</th><th>2030</th><th>2035</th></tr>
<tr><td rowspan="3">Turn down flexibility</td><td rowspan="3">510MWh (0.41%)</td><td>DD, low</td><td>738MWh (0.67%)</td><td>738 MWh (0.64%)</td></tr>
<tr><td>ED, mid</td><td>798 MWh (0.65%)</td><td>1260 MWh (0.93 %)</td></tr>
<tr><td>EG, high</td><td>877 MWh (0.66%)</td><td>1386 MWh (0.94 %)</td></tr>
<tr><td rowspan="3">Turn up flexibility</td><td rowspan="3">n/a</td><td>DD, low</td><td>n/a</td><td>n/a</td></tr>
<tr><td>ED, mid</td><td>n/a</td><td>n/a</td></tr>
<tr><td>EG, high</td><td>n/a</td><td>n/a</td></tr>
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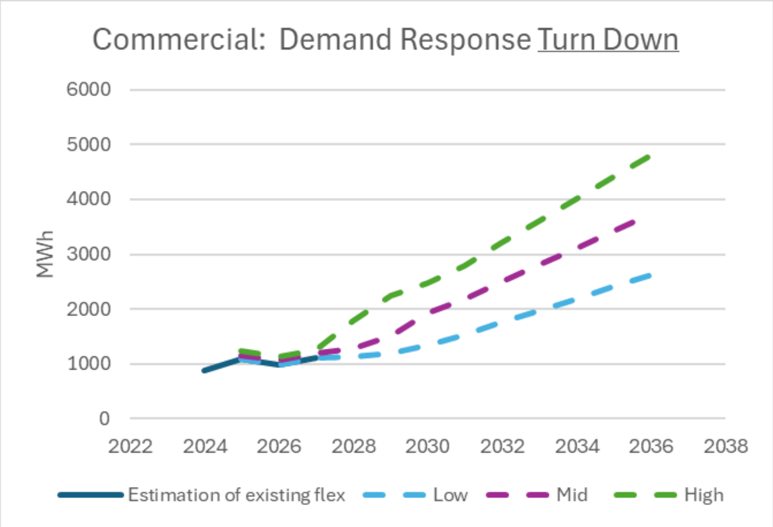
<table>
<tr><th colspan="2">Trajectories or demand turn-down and demand turn-up</th></tr>
<tr><td>

a</td><td>Assumed not available
b</td></tr>
</table>

Figure 15 Projections of flexible volume from non-residential flexibility from DSU for (a) turn down and (b) turn up.

Non-residential flexibility from commercial and industrial heat

Flexibility from the industrial and commercial customers with major heating demand (e.g. aluminium smelters) that can be switched to other forms of fuel (e.g. gas or hydrogen) or a large volume of aggregated or smart heat pumps/air conditioners that can temporarily reduce the demand. **Includes**: switching energy vectors from electrode boilers to gas boilers for industrial customers and demand response from commercial heat pumps/air conditioning units. **Excludes**: any form of thermal storage.

Relevant NEDS actions:

- (direct impact) 2.3 Increase flexibility provided by DSUs (EirGrid): Develop and publish a plan of work to improve active participation and performance of DSUs in the market and remove barriers. Plan to clarify expectations on DSUs to increase the flexibility, consider industry-suggested code changes and describe technical updates to be implemented for TSO and MO systems.
- (direct impact) 2.4 Market changes to enable increased flexibility (EirGrid): Assess and report on status and potential solutions to enable energy market participants to offer increased flexibility through the energy market, supporting more flexible trading of demand, engaging suppliers more actively, and ensuring technology neutrality in market and dispatch systems.
- (direct impact) 2.6 TSO demand flexibility product (EirGrid): EirGrid to keep under review further potential options for TSO demand flexibility products, reporting output to CRU.
- (direct impact) 2.18 Changes required for dispatchable consumption (EirGrid): Implement code and system changes to better accommodate "dispatchable consumption" proposals and upwards demand response

- (enabling/indirect impact) 2.19 Electricity system emissions information (EirGrid): Review approach to reporting of real time emissions from TSO dispatch of the system engaging with the CRU. Develop approach to integrate emissions data and reporting into wider TSO decision-making where it is possible to do so
- (enabling/indirect impact) 3.2: Enhanced quality and accessibility of network information (EirGrid): Enhance quality and accessibility of information relating to areas of the network, where capacity is available and future network development plans.

The methodology for estimating demand response volume is based on projections of the proportion of households participating in energy sharing and their ability to deliver demand response during peak time or energy that can be shifted to follow available generation.

Methodology:	
Demand turn-down volume: Number of electrode boilers * Boiler rating * Duration of response(hrs) + Number of units* Participation rate (%) * Response duration (hrs)	**Demand turn-up volume**: Number of units* Participation rate (%) * Response duration (hrs)
Assumptions	
• Aughinish Alumina currently have one 25 MW electrode boiler, which is expected to scale up to 3 electrode boilers by 2030. Flexibility achieved by switching on gas boilers. Available duration 24hrs. • No demand turn-up available from electrode boilers. • Commercial heat pumps have an average consumption of 2.4kW with average duration of turn down response of 1.5 hrs.	
Limitations	
• Operation of the electrode boilers is governed by electricity prices. • Demand turn-up from commercial heat pumps does not account for the impact on the local distribution networks and the limitation on the permitted response due to constraints • Not considering retrofitting smart controls or interface compatibility with the heat pump or thermal store manufacturers	

Several aspects influence how scenarios impact the inputs to the methodology:

Scenarios	
Aspects that impact the volume	**Potential impact on the forecast**
Incentives and building regulations for commercial heat pumps	Number of units (commercial heat pumps)
Standardisation of Battery Management System (BMS) and flex-ready heat pumps from design	DSR Participation rate (%)
Economic conditions and the cost of electricity	Number of electrode boilers
New DSR flexibility products offer additional revenue streams	DSR Participation rate (%)

Scenario	Scenario assumptions	Impact
Delayed Delivery (DD, low)	Economic conditions and the cost of electricity slow down the uptake.	By 2030: 2 electrode boilers, 39k commercial heat pumps, 40% participation rate. By 2035: 4 electrode boilers, 45k commercial heat pumps, 79% participation rate.
Expected Delivery (ED, mid)	Incentives and economic conditions support the targets. BMS and heat pumps become more compatible with flexibility.	By 2030: 3 electrode boilers, 50k commercial heat pumps, 50% participation rate. By 2035: 5 electrode boilers, 63k commercial heat pumps, 79% participation rate.
Enhanced Growth (EG, high)	Opportunities for flexibility, emissions incentives and better economic outlook increase scale of electrification.	By 2030: 3 electrode boilers, 55k commercial heat pumps, 60% participation rate. By 2035: 6 electrode boilers, 73k commercial heat pumps, 83% participation rate.

The methodology and the assumptions produced are applied to the following projects for the key years and projection over time:

Projections				
Decision paper projection	**2030**	**Scenario**	**2030**	**2035**
Turn down flexibility	MWh (0.06%)	DD, low	1256MWh (1.15%)	2526 MWh (2.17 %)
		ED, mid	1890MWh (1.55%)	3181 MWh (2.36 %)
		EG, high	2520MWh (1.89%)	3818 MWh (2.59 %)
Turn up flexibility	MWh (0.06%)	DD, low	84MWh (0.08%)	188 MWh (0.2 %)
		ED, mid	135MWh (0.1%)	271 MWh (0.2 %)
		EG, high	180MWh (0.01%)	327 MWh (0.2 %)

Trajectories or demand turn-down and demand turn-up

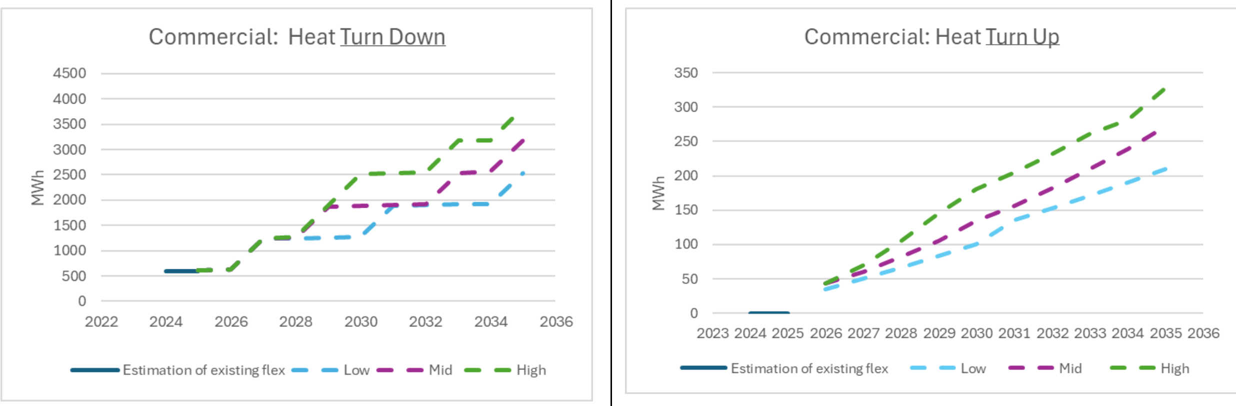


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Figure 16 Projections of flexible volume from commercial heat for (a) turn down and (b) turn up.

Non-residential flexibility from commercial fleet smart charging

Flexibility from commercial on-site or depot Smart EV charging is delivered by scheduling when EVs are charging in response to external signals, such as a control schedule from an aggregator or price signals. **Includes:** Smart charging of electric Light Commercial Vehicles (eLCV), electric Heavy Goods Vehicle (eHGVs), and EV-buses charging at depots or fleet carparks **Excludes:** any other public charging

Relevant NEDS actions:

- (direct impact) 1.3 Smart EV charging services (ESBN): Engage across relevant parties to develop propositions for smart charging services, including an exploratory investigation of vehicle-to-grid (V2G) services. Establish working group to explore barriers and enablers. Publish programme of work.
- (enabling/indirect impact) 1.11 Microgeneration operational issues (ESBN): Review the impact of operational challenges for System Operators associated with high levels of microgeneration, given the potential growth of installations, and report to the CRU.
- (enabling/indirect impact) 1.12 Market design changes for secondary measurement devices (CRU): Consultation to establish what market design changes will be required for secondary measurement devices, and the timelines for implementing those changes.
- (enabling/indirect impact) 1.13 Licences for aggregation and demand response (CRU): Consult on development of new licences for aggregation and demand response.
- (enabling/indirect impact) 2.6 TSO demand flexibility product (EirGrid): EirGrid to keep under review further potential options for TSO demand flexibility products, reporting output to CRU.
- (enabling/indirect impact) 2.13 Smart charging flexibility product (ESBN): Develop and launch new smart charging flexibility product and/or service and ensure the delivery is fair and effective in enabling demand flexibility through EVs.
- (enabling/indirect impact) 2.16 Optimise EV fleet charging (ESBN): Develop and publish plan to optimise EV fleet charging through technology and software solutions.

- (enabling/indirect impact) 2.17 Smart EV charging availability (EBSN): Develop and publish technical assessment of how the available smart EV charging and V2G capacity can be maximised through network operations.

The methodology for estimating demand response volume is based on projections of the number and type of commercial electric vehicles, their flexible charging capacity, and participation rates.

Methodology:	
Demand turn-down volume: Number of vehicles of each type * Flexible capacity (kWh) * Participation rates (%)	**Demand turn-up volume**: Number of vehicles of each type * Flexible capacity (kWh) * Participation rates (%)
Assumptions	
• 20% of battery capacity can be used for demand response on all vehicles • Nominal capacities: 80kWh (eLCV), 600kWh (eHGV), 250kWh (eBus), adjusted by the flexibility adjustment factor per scenario • Steady growth in participation rate from 0% in 2025 to 2030 values	
Limitations	
• Typical fleet operation schedules and differences in schedules related to the nature of businesses are not considered. This implies that the participation rate is applied uniformly to all vehicle types • Smart charging is only applied when vehicles are on-site or at the depot. • Demand turn-up would depend on the specific operation schedule of the commercial EVs, the demand profile of the commercial site and the maximum import capacity of the site	

Several aspects influence how scenarios impact the inputs to the methodology:

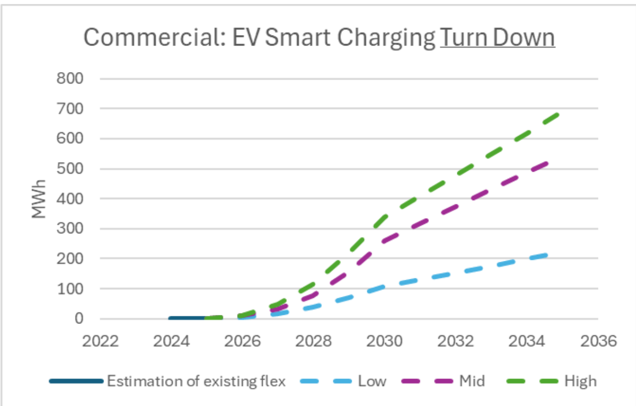
Scenarios		
Aspects that impact the volume		**Potential impact on the forecast**
Availability of grants, installers and wider market conditions		Number of EV charger units
Customer familiarity and education		Participation rate (%)
Number of enabled and smart chargers		Turn down capacity (kW)
Frequency of override by customer and vehicle usage		Response duration (hrs)
Availability of grants, installers and wider market conditions		Number of EV charger units
Scenario	**Scenario assumptions**	**Impact**
Delayed Delivery (DD, low)	Maintaining current trajectory of EV fleet growth, lower capacity is available for flexibility	By 2030: 71.2k eLCVs, 2.6k eHGVs, 1.1k eBuses, participation rate 10% By 2035: 137k eLCVs, 5.4k eHGVs, 2.1k eBuses, participation rate 20%

Expected Delivery (ED, mid)	Faster uptake of commercial EVs (incl. Buses), more capacity available for flexibility	By 2030: 95k eLCVs, 3.5k eHGVs, 1.5k eBuses, participation rate 13% By 2035: 183k eLCVs, 7.2k eHGVs, 2.8k eBuses, participation rate 26%
Enhanced Growth (EG, high)	Accelerated participation, scale of and duration of response	By 2030: 104k eLCVs, 3.8k eHGVs, 1.6k eBuses, participation rate 14% By 2035: 201k eLCVs, 7.9k eHGVs, 3k eBuses, participation rate 28%

The methodology and the assumptions produced are applied to the following projects for the key years and projection over time:

Projections				
Decision paper projection	**2030**	**Scenario**	**2030**	**2035**
Turn down flexibility	MWh (0.06%)	DD, low	106MWh (0.1%)	432 MWh (0.37 %)
		ED, mid	260MWh (0.21%)	1060 MWh (0.76 %)
		EG, high	338MWh (0.25%)	1344 MWh (0.91 %)
Turn up flexibility	MWh (0.06%)	DD, low	106MWh (0.1%)	432 MWh (0.37 %)
		ED, mid	260MWh (0.21%)	1060 MWh (0.76 %)
		EG, high	338MWh (0.25%)	1344 MWh (0.91 %)

Trajectories or demand turn-down and demand turn-up



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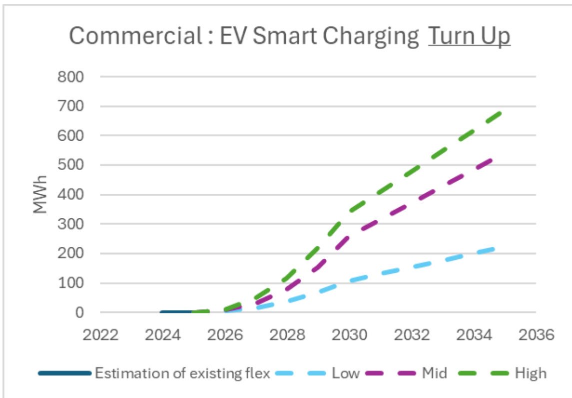


b

Figure 17 Projections of flexible volume from commercial fleet smart charging for (a) turn down and (b) turn up.

Non-residential flexibility from commercial fleet V2X charging

Flexibility from the on-site V2X for commercial fleet across three types of compatible vehicles: light commercial vehicles, buses and heavy goods vehicles. **Includes:** V2G on-site from Light commercial vehicles, eHGVs and buses charging at commercial sites/depots. **Excludes:** any other public charging and on-site smart charging

Relevant NEDS actions:

- (direct impact) 1.3 Smart EV charging services (ESBN): Engage across relevant parties to develop propositions for smart charging services, including an exploratory investigation of vehicle-to-grid (V2G) services. Establish working group to explore barriers and enablers. Publish programme of work.
- (enabling/indirect impact) 1.11 Microgeneration operational issues (ESBN): Review the impact of operational challenges for System Operators associated with high levels of microgeneration, given the potential growth of installations, and report to the CRU.
- (enabling/indirect impact) 1.12 Market design changes for secondary measurement devices (CRU): Consultation to establish what market design changes will be required for secondary measurement devices, and the timelines for implementing those changes.
- (enabling/indirect impact) 1.13 Licences for aggregation and demand response (CRU): Consult on development of new licences for aggregation and demand response.
- (enabling/indirect impact) 2.6 TSO demand flexibility product (EirGrid): EirGrid to keep under review further potential options for TSO demand flexibility products, reporting output to CRU.
- (enabling/indirect impact) 2.13 Smart charging flexibility product (ESBN): Develop and launch new smart charging flexibility product and/or service and ensure the delivery is fair and effective in enabling demand flexibility through EVs.
- (enabling/indirect impact) 2.16 Optimise EV fleet charging (ESBN): Develop and publish plan to optimise EV fleet charging through technology and software solutions.
- (enabling/indirect impact) 2.17 Smart EV charging availability (EBSN): Develop and publish technical assessment of how the available smart EV charging and V2G capacity can be maximised through network operations.

The methodology for estimating demand response volume is based on projections of the number and type of V2X compatible commercial electric vehicles, their flexible charging capacity, and participation rates.

Methodology:	
Demand turn-down volume: Number of vehicles of each type * Flexible capacity (kWh) * Participation rates (%)	**Demand turn-up volume**: Assumed to be symmetrical
Assumptions	
• 10% of battery capacity can be used for V2G on the compatible vehicles (20%) • Nominal capacities: 80kWh (LCV), 600kWh (eHGV), 250kWh (eBus), adjusted by the flexibility adjustment factor per scenario • Steady growth in participation rate, but half compared to smart charging.	

Limitations
• All V2G smart charging installations and the compatible EVs are assumed to have homogeneous behaviour and requirements. Averages across vehicle types and usage patterns are used in the estimation. • Demand turn-up would depend on the specific operation schedule of the commercial EVs, the demand profile of the commercial site and the maximum import capacity of the site

Several aspects influence how scenarios impact the inputs to the methodology:

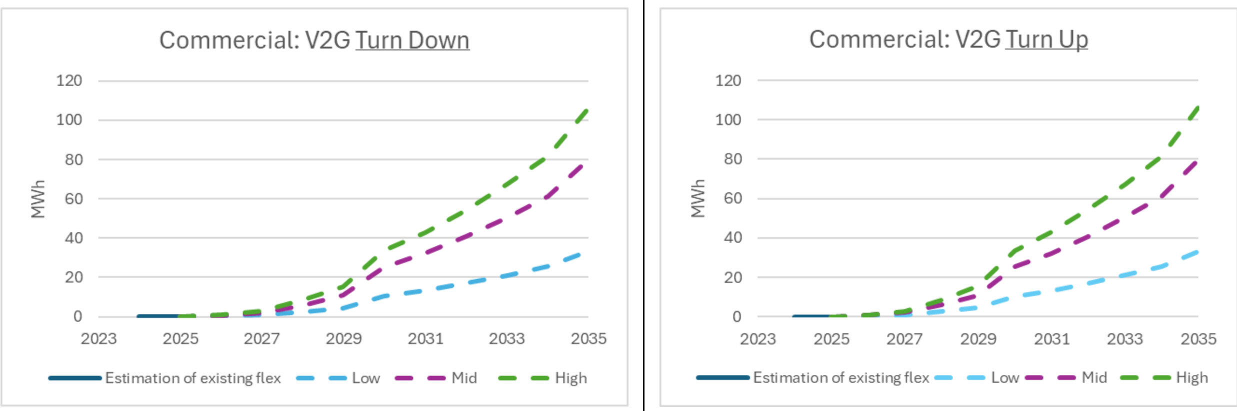
Scenarios		
Aspects that impact the volume		**Potential impact on the forecast**
Availability and cost of the V2G-compatible chargers, including supplier and aggregator offerings		Number of V2G charger units
Availability and cost of V2G-compatible LCVs, eHGVs and eBuses		Number of V2G charger units
Availability of fleet and optimisation of fleet schedules		Response duration (hr)
		Participation rate (%)
Scenario	**Scenario assumptions**	**Impact**
Delayed Delivery (DD, low)	Maintaining current trajectory of EV fleet growth, lower capacity is available for flex.	By 2030: 14.2k LCVs, 525 eHGVs, 225 eBuses, participation rate 5% By 2035: 27k LCVs, 1k eHGVs, 419 eBuses, participation rate 10%
Expected Delivery (ED, mid)	Faster uptake of commercial EVs (inc Buses), more capacity available for flexibility	By 2030: 19k LCVs, 700 eHGVs, 300 eBuses, participation rate 7% By 2035: 36k LCVs, 1.4k eHGVs, 559k eBuses, participation rate 13%
Enhanced Growth (EG, high)	Accelerated participation with advanced hardware and aggregation services improves the scale of and duration of response.	By 2030: 20.9k LCVs, 770 eHGVs, 330 eBuses, participation rate 8% By 2035: 40.3k LCVs, 1.5k eHGVs, 615 eBuses, participation rate 14%

The methodology and the assumptions produced are applied to the following projects for the key years and projections over time:

Projections				
Decision paper projection	**2030**	**Scenario**	**2030**	**2035**
Turn down flexibility	MWh (0.06%)	DD, low	5.9 MWh (0.01%)	21.6 MWh (0.02%)
		ED, mid	14.4 MWh (0.01%)	52.3 MWh (0.04 %)

		EG, high	19.2 MWh (0.01%)	69.6 MWh (0.05 %)
Turn up flexibility	MWh (0.06%)	DD, low	106MWh (0.1%)	432 MWh (0.37 %)
		ED, mid	260MWh (0.21%)	1060 MWh (0.76 %)
		EG, high	338MWh (0.25%)	1344 MWh (0.91 %)

Trajectories or demand turn-down and demand turn-up



a

b

Figure 18 Projections of flexible volume from commercial fleet V2G charging for (a) turn down and (b) turn up.

Non-residential flexibility from BtM generation

Currently, flexibility from commercial generation behind the meter is delivered through demand response.

Non-residential flexibility from BtM Storage

Currently, flexibility from commercial energy storage behind the meter is delivered through demand response.

Non-residential flexibility from public EV hubs

Flexibility from publicly accessible EV Charging hubs, purpose-built or part of motorway service stations with variable pricing, charging higher rates during peak demand periods and lower rates during peak generation. **Includes:** publicly available EV hubs with multiple high-powered chargers and facilities **Excludes:** any other public charging, BtM Storage, generation and EV/V2G on commercial properties

Relevant NEDS actions:

- (direct impact) 1.3 Smart EV charging services (ESBN): Engage across relevant parties to develop propositions for smart charging services, including an exploratory investigation of vehicle-to-grid (V2G) services. Establish working group to explore barriers and enablers. Publish programme of work.

- (direct impact) 1.4 Review of policy & supports for EV charging (ZEVI) Review measures that support EV charging with a view to identifying how they can better support flexibility. This should include a review of depot charging for Heavy Duty Vehicles to consider how this type of charging can support flexibility potential.
- (direct impact) 2.8 Flexibility Needs Assessment (CRU): Undertake and publish assessment of flexibility needs in line with ACER flexibility-needs assessment methodology, and other relevant considerations (e.g. the assessment of EV recharging points operation & potential contribution, Alternative Fuels Infrastructure Regulation - Articles 15 (3) and (4)). Engage with fellow regulators via ACER and Council of European Energy Regulators (CEER) to maximise learning from others, and to influence direction of flexibility market design across the EU.
- (enabling/indirect impact) 1.11 Microgeneration operational issues (ESBN): Review the impact of operational challenges for SOs associated with high levels of microgeneration, given the potential growth of installations, and report to the CRU.
- (enabling/indirect impact) 1.12 Market design changes for secondary measurement devices (CRU): Consultation to establish what market design changes will be required for secondary measurement devices, and the timelines for implementing those changes.
- (enabling/indirect impact) 1.13 Licences for aggregation and demand response (CRU): Consult on development of new licences for aggregation and demand response.
- (enabling/indirect impact) 2.6 TSO demand flexibility product (EirGrid): EirGrid to keep under review further potential options for TSO demand flexibility products, reporting output to CRU.
- (enabling/indirect impact) 2.13 Smart charging flexibility product (ESBN): Develop and launch new smart charging flexibility product and/or service and ensure the delivery is fair and effective in enabling demand flexibility through EVs.
- (enabling/indirect impact) 2.16 Optimise EV fleet charging (ESBN): Develop and publish plan to optimise EV fleet charging through technology and software solutions.
- (enabling/indirect impact) 2.17 Smart EV charging availability (EBSN): Develop and publish technical assessment of how the available smart EV charging and V2G capacity can be maximised through network operations.

The methodology for estimating demand response volume is based on projections of the EV hubs throughout Ireland, their utilisation and the response of customers to price signals.

Methodology:	
Demand turn-down volume: Number of hubs * Demand capacity per (MW) * Price-responsive demand (%) * Duration of peak price period (hrs)	**Demand turn-up volume**: Symmetrical to turn down flexibility volume down.
Assumptions	
• Assuming a time-of-use pricing structure for EV charging at the hub during the peak-demand period, which reduced the number if charring session during the peak demand period by 50% for 2 hours.	

• Demand capacity per hub can be between 8MW and 1MW (4-12 ultra-fast + 2-4 fast DC chargers) •
Limitations
• Price responsiveness of EV hub users is assumed at 50% based on limited empirical evidence. • Seasonal and geographic variation in hub utilisation is not modelled.

Several aspects influence how scenarios impact the inputs to the methodology:

Scenarios		
Aspects that impact the volume		**Potential impact on the forecast**
Availability of grants, installers and wider market conditions		Number of EV charger units
Customer familiarity and education		Participation rate (%)
Number of enabled and smart chargers		Turn down capacity (kW)
Frequency of override by customer and vehicle usage		Response duration (hrs)
Availability of grants, installers and wider market conditions		Number of EV charger units
Scenario	**Scenario assumptions**	**Impact**
Delayed Delivery (DD, low)	Delayed implementation of AFIR. Slower uptake of private and fleet EVs reduces the demand for EV hubs.	By 2030: 90 EV charging hubs
Expected Delivery (ED, mid)	Greater number of EV hubs with additional storage and demand capacity.	By 2030: 106 EV charging hubs
Enhanced Growth (EG, high)	An additional increase in scale is due to coordinated planning. Price signals encourage flexibility. Higher demand from the number of EVs.	By 2030: 120 EV charging hubs

The methodology and the assumptions produced are applied to the following projects for the key years and projections over time:

Projections				
Decision paper projection	**2030**	**Scenario**	**2030**	**2035**
Turn down flexibility	MWh (0.06%)	DD, low	160MWh (0.15%)	230 MWh (0.2 %)
		ED, mid	220MWh (0.18%)	260 MWh (0.19 %)
		EG, high	270MWh (0.2%)	465 MWh (0.31 %)
Turn up flexibility	MWh (0.06%)	DD, low	160MWh (0.15%)	230 MWh (0.2 %)

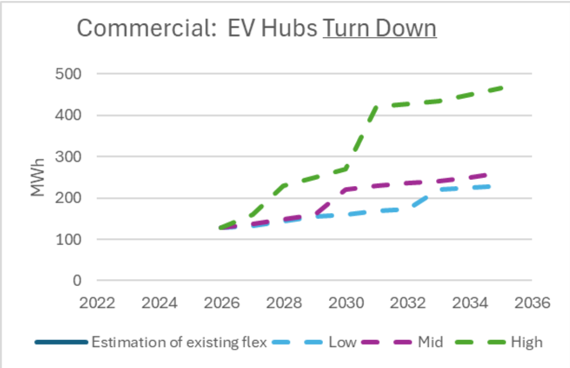
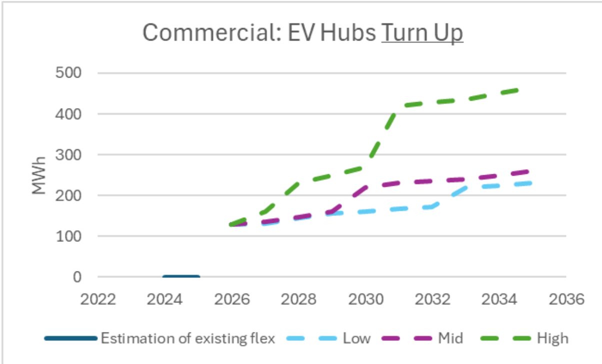
		ED, mid	220MWh (0.18%)	260 MWh (0.19 %)
		EG, high	270MWh (0.2%)	465 MWh (0.31 %)
Trajectories or demand turn-down and demand turn-up				
 a		 b		

Figure 19 Projections of flexible volume from EV charging hubs for (a) turn down and (b) turn up.

Non-residential flexibility from heat networks

Flexibility from district heating networks is delivered by adjusting the electrical consumption of central heating plant equipment (e.g. large heat pumps and electric boilers) in coordination with thermal energy storage. By treating the heat network as a "thermal battery", these systems can shed demand during peak periods (drawing on stored hot water instead of consuming power) or increase demand during off-peak periods (using surplus electricity to charge thermal stores). **Includes**: conversion of electricity to heat via large power-to-heat units (such as electrode boilers or centralized heat pumps) that are incorporated into multi-building district heating networks alongside hot-water storage to buffer heat supply. **Excludes**: single-site industrial electrode boilers or heat pumps not part of a shared heat network (considered separately under large energy users), and individual building-level heat pumps (considered under residential and commercial heat flexibility).

Relevant NEDS actions:

- (direct impact) 2.3 Increase flexibility provided by DSUs (EirGrid): Develop and publish a plan of work to improve active participation and performance of DSUs, removing barriers to new flexible loads – creating market opportunities for aggregated resources such as heat networks to provide grid services.
- (direct impact) 2.18 Changes required for dispatchable consumption (EirGrid): Implement code and system changes to better accommodate "dispatchable consumption" in scheduling and dispatch, enabling large controllable demands (e.g. power-to-heat units) to participate in TSO dispatch for upward demand response.
- (enabling/indirect impact) 2.6 TSO demand flexibility product (EirGrid): EirGrid to examine new options for demand-side flexibility products – supporting future aggregator models that could include clusters of heat network loads.

<table>
<tr><th colspan="2">Methodology:</th></tr>
<tr><td>Demand turn-down volume:
Number of DH networks * Power-to-heat capacity per network (MW) * Participation rate (%) * Duration of shedding (hours)</td><td>Demand turn-up volume:
Number of DH networks * Power-to-heat capacity per network (MW) * Participation rate (%) * Duration of increased consumption (hours)</td></tr>
<tr><th colspan="2">Assumptions</th></tr>
<tr><td colspan="2">• Only a handful of heat networks are expected to be operational by 2030, expanding in the 2030s.
• Assuming new networks to integrate flexible electric heating capacity sized at 20–50% of peak heat load plus thermal storage providing at least 2–4 hours of full-load output.[28]
• Power to heat deliver turn down repose at full capacity for 2 hours and turn up for 4 hours
• Appropriate district heating control and monitoring systems are integrated with the building management systems</td></tr>
<tr><th colspan="2">Limitations</th></tr>
<tr><td colspan="2">• Assuming suitable market signals and market access are present to incentivise and monetise flexibility.
• Flexible use of heat generation does not substantially impact comfort and operation of the customers on the network or the shared sources of heat.</td></tr>
</table>

Several aspects influence how scenarios impact the inputs to the methodology:

<table>
<tr><th colspan="3">Scenarios</th></tr>
<tr><th colspan="2">Aspects that impact the volume</th><th>Potential impact on the forecast</th></tr>
<tr><td colspan="2">Number & size of networks</td><td>Total power to heat capacity</td></tr>
<tr><td colspan="2">Proportion of power to heat capacity and availability of thermal storage</td><td>Response duration</td></tr>
<tr><td colspan="2">Integration and automation of controls and dispatch</td><td>Participation rate</td></tr>
<tr><th>Scenario</th><th>Scenario assumptions</th><th>Impact</th></tr>
<tr><td>Delayed Delivery (DD, low)</td><td>Slow deployment of heating networks projects; limited policy support or funding delays. Most heat networks rely on conventional heat sources without integrated power-to-heat.</td><td>Only 1–2 small networks operational by 2030, and a single larger network by 2035 with minimal electrification. Very low (a few MW by 2030; ~45 MW by 2035 as a late addition for backup). 60% of Heat networks participate explicitly; flexibility used only implicitly when economic. Shorter shedding duration due to smaller storage (~2 hrs).</td></tr>
<tr><td>Expected Delivery (ED, mid)</td><td>Gradual rollout aligned with current plans (NDP and Heat Policy). Key networks delivered with power-to-heat integration by the mid-2030s.</td><td>A few major networks (e.g. Dublin, plus 1–2 city schemes) online by 2030, expanding to ~5 networks by 2035.
Moderate growth (~20 MW by 2030 rising to ~150 MW by 2035) as new schemes include e-boilers/heat pumps for low-carbon backup.</td></tr>
</table>

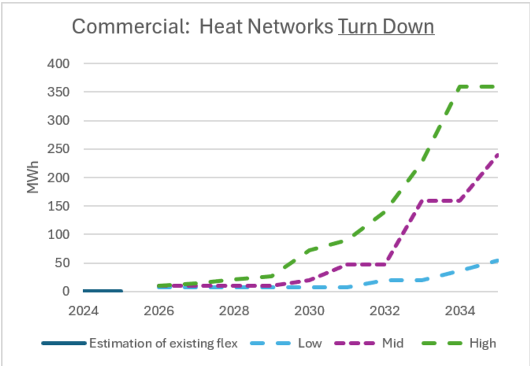
28

		Thermal storage provides ~2 hrs peak shaving and 4–6 hrs load increase per day.
Enhanced Growth (EG, high)	Accelerated heat network expansion and electrification, driven by strong climate policy and funding. All new networks are "flexibility-ready" and delivered to schedule.	Multiple networks deployed in parallel (early Dublin scheme plus several regional networks by 2030; ~8 networks by 2035). Larger interconnected systems amplify scale. Rapid scale-up to meet decarbonisation targets (~40 MW by 2030, ~200+ MW by 2035 across all networks). Every major network has substantial electric boilers and large heat pumps plus storage. Nearly all power to heat capacity participates in flexibility markets via aggregators or DSUs. Thermal storage is widespread, allowing >4 hrs of continuous load modulation in each network.

The methodology and the assumptions produced are applied to the following projects for the key years and projection over time:

Projections				
Decision paper projection	**2030**	**Scenario**	**2030**	**2035**
Turn down flexibility	-	DD, low	7.2 MWh (0.01%)	43 MWh (0.04 %)
		ED, mid	19.2 MWh (0.02%)	80 MWh (0.06 %)
		EG, high	72 MWh (0.05%)	360 MWh (0.24 %)
Turn up flexibility	-	DD, low	14.4 MWh (0.01%)	86.5 MWh (0.01 %)
		ED, mid	38 MWh (0.03%)	160 MWh (0.1 %)
		EG, high	160 MWh (0.12%)	800MWh (0.59 %)

Trajectories or demand turn-down and demand turn-up



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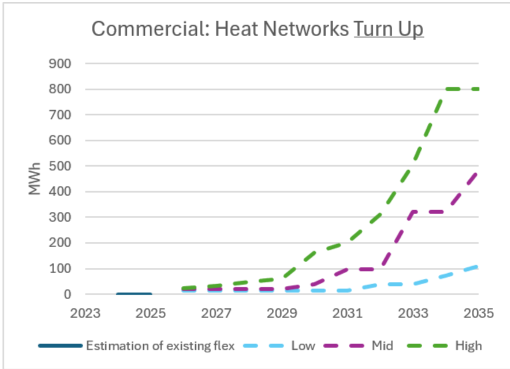


b

Figure 20 Projections of flexible volume from heat networks for (a) turn down and (b) turn up.

Non-residential flexibility from green energy parks

Flexibility from the GEPs is enabled by flexible demand from customers in GEPs, which are incentivised to be flexible to maximise matching with local (for inland GEPs) or paired offshore generation (coastal GEPs). Further flexibility per GEP is represents the capacity of local energy storage and hydrogen generation (coastal GEPs) that is not used for local balancing of demand and generation on a regular basis. **Includes**: Large energy users and industrial demand across sectors co-located and operated as a unit with renewable generation, low carbon energy source and storage with some level of self-sustainability. **Excludes**: Individual LEUs with a dedicated network connection, not part of GEPs.

Relevant NEDS actions:

- (direct impact): 3.3 Monitor work being undertaken to assess the role that integrated energy parks could play in our future energy system (CRU): Monitor work being undertaken as part of the National Hydrogen Strategy to assess the role that integrated energy parks could play in our future energy system, including their potential benefits and the possible barriers (market, legal or other) that may exist. (Ref: National Hydrogen Strategy Action 6).

The methodology for estimating demand response volume is based on estimated daily energy demand for demand customers inside a GEP and onsite storage:

Methodology:	
Demand turn-down volume: Number of GEP per type * Demand capacity per park type (MW) * Flexible demand down proportion (%) + Energy storage capacity (MW) * Duration available for additional response (hr))	**Demand turn-up volume**: Number of GEP per type * Demand capacity per park type (MW) * Flexible demand up proportion (%) + Energy storage capacity (MW) * Duration available for additional response (hr))

Assumptions
• The number of GEPs is based on the projection of inland and coastal[29] candidate sites: • Coastal sites paired with offshore wind and include hydrogen conversion and battery energy storage. • Due to proximity to offshore wind potential, coastal GEPs are assumed to have greater demand and storage capacity. • Inland sites have onshore wind, solar and battery storage. • Assuming % of daily demand across customers per GEPs site to be flexible • Coastal GEPs until 2028[30]
Limitations
• Exact flexibility delivered through GEPs is driven by the nature of LEU operations and their ability to be flexible, including forecasting and coordination between demand, storage and generation.

Several aspects influence how scenarios impact the inputs to the methodology:

<table>
<tr><th colspan="3">Scenarios</th></tr>
<tr><th colspan="2">Aspects that impact the volume</th><th>Potential impact on the forecast</th></tr>
<tr><td colspan="2">Wider economic conditions and policy impact on the growth of GEPs.</td><td>Daily energy demand (MWh);
Number of inland and coastal GEPs</td></tr>
<tr><td colspan="2">Incentives to use of BtM or local generation flexibly</td><td>Proportion of daily energy use for demand turn-down (%)</td></tr>
<tr><th>Scenario</th><th>Scenario assumptions</th><th>Impact</th></tr>
<tr><td>Delayed Delivery (DD, low)</td><td>Delays and complexity in the implementation of LEAP actions. Uncertainty in policy direction and wider economic challenges.</td><td>By 2030: 1 coastal GEP (300MW demand capacity with 15% flexible demand, 5MWh available flex from storage) and 1 inland GEP (100MW demand capacity with 10% flexible demand, 2.5MWh available from energy storage)

By 2035: 2 coastal GEPs (600MW demand capacity with 10% flexible demand, 5MWh available flex from storage) and 2 inland GEPs (200MW demand capacity with 10% flexible demand, 2.5MWh available flex from storage)</td></tr>
<tr><td>Expected Delivery (ED, mid)</td><td>Timely delivery of LEAP objectives. Efficient coordination and policy certainty lead to stronger investment on track to deliver 3 inland and 3 coastal GEPs by 2035.</td><td>By 2030: 2 coastal GEP (400MW demand capacity with 15% flexible demand, 7.5MWh available flex from storage) and 1 inland GEP (100MW demand capacity with 12% flexible demand, 5MWh available flex from storage)</td></tr>
</table>

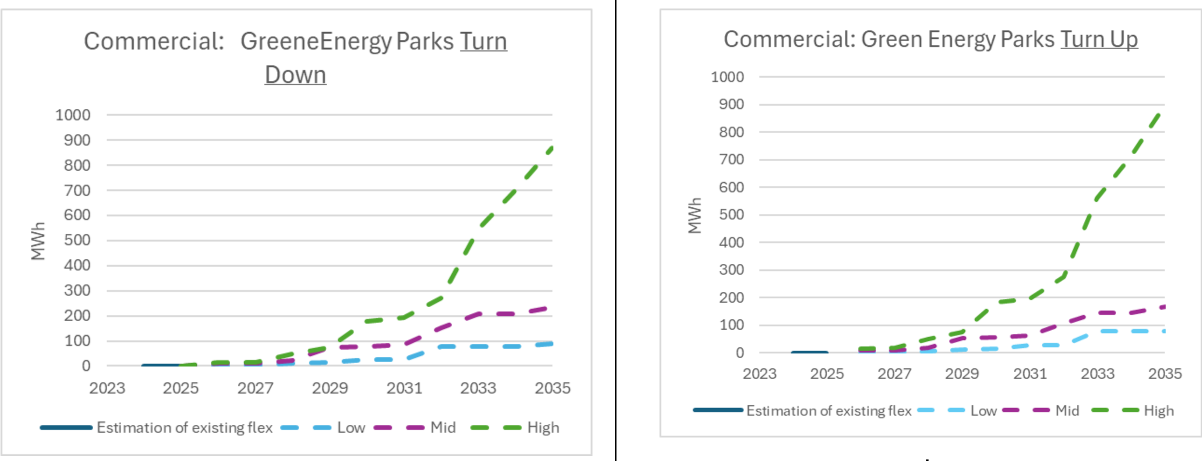
[29] An Economic Assessment of Green Energy Park Concepts, GDG for DETE, 2025
[30] LEAP Strategy, DETE, 2026

		By 2035: 3 coastal GEPs (800MW demand capacity with 10% flexible demand, 10MWh available flex from storage) and 3 inland GEPs (200MW demand capacity with 10% flexible demand, 10MWh available flex from storage)
Enhanced Growth (EG, high)	Timely delivery of LEAP objective and favourable market conditions for offshore wind and electrification of ports, including incentives for colocation of storage, lead to stronger investment on track to deliver 3 coastal and 4 inland GEPs by 2035.	By 2030: 2 coastal GEP (600MW demand capacity with 25% flexible demand, 20 MWh available flex from storage) and 1 inland GEP (150MW demand capacity with 15% flexible demand, 7.5MWh available flex from storage) By 2035: 4 coastal GEPs (1000MW demand capacity with 25% flexible demand, 200MWh available flex from storage) and 3 inland GEPs (400MW demand capacity with 15% flexible demand, 80MWh available flex from storage)

The methodology and the assumptions produced are applied to the following projects for the key years and projection over time:

Projections				
Decision paper projection	**2030**	**Scenario**	**2030**	**2035**
Turn down flexibility	-	DD, low	27.5MWh (0.03%)	87.5 MWh (0.07 %)
		ED, mid	78.5MWh (0.06%)	233 MWh (0.17 %)
		EG, high	178.8MWh (0.13%)	870 MWh (0.59 %)
Turn up flexibility	-	DD, low	27.5MWh (0.03%)	87.5 MWh (0.07 %)
		ED, mid	78.5MWh (0.06%)	233 MWh (0.17 %)
		EG, high	178.8MWh (0.13%)	870 MWh (0.59 %)

Trajectories or demand turn-down and demand turn-up



a

b

Figure 21 Projections of flexible volume from Green Energy Parks for (a) turn down and (b) turn up.

Non-residential flexibility from large energy users

Flexibility from the LEUs is provided by the operation of generation and storage on-site in response to markets and flexibility services[31]. **Includes**: BtM or local generation and energy storage, shift in electricity demand with modifications to operations (e.g. cooling, geographical computation shift). **Excludes:** LEUs integrated within Green Energy parks.

Relevant NEDS actions:

- (direct impact): 3.1 Publication of new LEU connection policy (CRU): (a) Publish the next stage of consultation. (b) Publish and implement new connection policy for LEUs.
- (enabling/indirect impact) 2.6 TSO demand flexibility product (EirGrid), EirGrid to keep under review further potential options for TSO demand flexibility products, reporting output to CRU.
- (enabling/indirect impact) 3.3 Monitor work being undertaken to assess the role that integrated energy parks could play in our future energy system (CRU): Monitor work being undertaken as part of the National Hydrogen Strategy to assess the role that integrated energy parks could play in our future energy system, including their potential benefits and the possible barriers (market, legal or other) that may exist. (Ref: National Hydrogen Strategy Action 6).

The methodology for estimating demand response volume is based on estimated daily energy demand for LEUs[32] and the ability to vary the amount of BtM or local generation that offsets that demand.

[31] Action 4, LEAP Strategy

[32] Based EirGrid's All Island's Resource Adequacy Assessment up to 2034 and linear extrapolation to 2035. All-Island Resource Adequacy Assessment 2025-2034

Methodology:	
Demand turn-down volume: Daily energy demand (MWh) * Proportion daily energy use for demand turn-down (%)	**Demand turn-up volume**: Assumed not available
Assumptions	
• Total annual energy consumption across all LEU's based on the Generation Capacity Statement • Assuming % of daily demand across all LEUs to be flexible • Slowing in LEU demand growth is compensated by the increased flexibility with respect to the scenarios.	
Limitations	
• Not distinguishing by nature of LEU operations or its location.	

Several aspects influence how scenarios impact the inputs to the methodology:

Scenarios		
Aspects that impact the volume		**Potential impact on the forecast**
Wider economic conditions and policy impact on the growth of LEU connections.		Daily energy demand (MWh)
Incentives to use of BtM or local generation flexibly		Proportion of daily energy use for demand turn-down (%)
Scenario	**Scenario assumptions**	**Impact**
Delayed Delivery (DD, low)	Lower volume of LEU connections, all paired with de-rated generation and deliver limited flexibility	By 2030: 36MWh average daily demand with 10% flexible demand By 2035: 41MWh average daily demand with 20% flexible demand
Expected Delivery (ED, mid)	Low participation in flexibility, but those who are participating have high flexibility through de-rated generation	By 2030: 38MWh average daily demand with 14.5% flexible demand By 2035: 41MWh average daily demand with 30% flexible demand
Enhanced Growth (EG, high)	Slightly higher volume of LEU connections, some with generation not classed as autoproducers that are subject to MDC and others have higher ability to	By 2030: 36MWh average daily demand with 23% flexible demand By 2035: 42MWh average daily demand with 50% flexible demand

The methodology and the assumptions produced are applied to the following projects for the key years and projection over time:

Projections				
Decision paper projection	**2030**	**Scenario**	**2030**	**2035**
Turn down flexibility	MWh (0.06%)	DD, low	3.65 MWh (0.003%)	8.3 MWh (0.01 %)
		ED, mid	5.32 MWh (0.004%)	12.7 MWh (0.01 %)
		EG, high	8.5MWh (0.01 %)	20.9 MWh (0.01 %)
Turn up flexibility	MWh (0.06%)	DD, low	0 MWh	0 MWh
		ED, mid	0 MWh	0 MWh
		EG, high	0 MWh	0 MWh

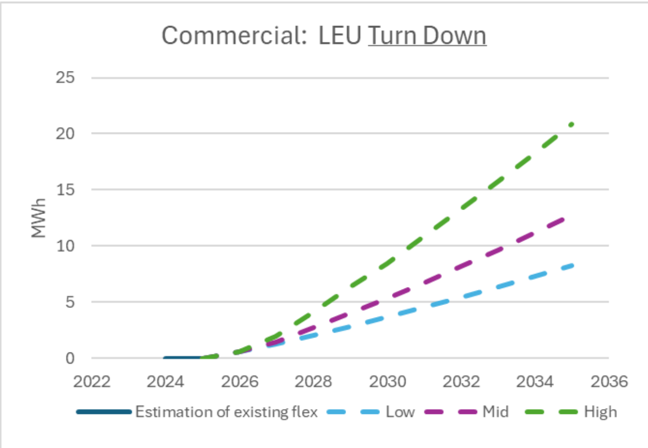
Trajectories or demand turn-down and demand turn-up	
 a	Assumed not available b

Figure 22 Projections of flexible volume from LEUs for (a) turn down and (b) turn up.

Utility-scale flexibility from network operation

Flexibility is achieved by reducing voltage at medium-voltage levels of the network to reduce the demand from resistive load – a technique known as Conservation Voltage Reduction (CVR). **Includes**: Voltage management through control of tap-changer position on primary substations. **Excludes:** any other customer-owned flexibility BtM Storage, generation and EV/V2G on commercial properties

Relevant NEDS actions:

- (enabling/indirect impact) 3.2A Enhanced quality and accessibility of network information (ESBN): Enhance quality and accessibility of information relating to areas of the network, where capacity is available and future network development plans.

The methodology for estimating demand response volume is based on projections of peak demand when CVR is likely to be applied, the scale of the network where CVR is applied and the magnitude of voltage reduction.

Methodology:	
Demand turn-down volume: Estimated peak demand * % of network enablement * Voltage reduction (%) * Duration	**Demand turn-up volume**: Assumed not available
Assumptions	
• Nominal 1% drop in voltage, delivers 1% peak reduction[33] • Maximum duration in response 30 mins • Roll-out of the functionality is done at the primary substation level from 2028[34] • Control room functionality and hardware rollout • Using national peak demand from Ten year generation capacity statemen	
Limitations	
• Specific response in MW depends on the load composition at the time and season of activation. In this case, assume a constant response.	

Several aspects influence how scenarios impact the inputs to the methodology:

Scenarios		
Aspects that impact the volume		**Potential impact on the forecast**
Integration of the solution in the control room and enablement across the network		% of network enablement
Rollout of network monitoring		Voltage reduction (%)
Scenario	**Scenario assumptions**	**Impact**
Delayed Delivery (DD, low)	Limited rollout of CVR across the network and a lower range of voltage reduction due to limited network monitoring availability, which helps ensure that the quality of supply remains satisfactory throughout the network	Voltage reduction is limited to 1.4%. By 2030 10% of the network is covered by CVR, and 55% by 2035,
Expected Delivery (ED, mid)	Better network monitoring enables a wider range of voltage reduction and more granular control across network locations.	Voltage reduction is extended to 3%. By 2030, 25% of the network is covered by CVR, and 35% by 2035.

[33] ESB Networks – Scenarios for 15-20% Flexible System Demand – National Network, Local Connections Programme

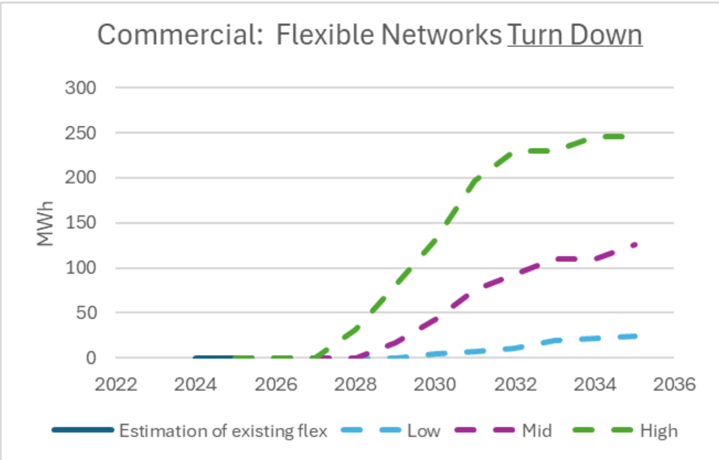
[34] ESBN **Flexibility Multi Year Plan 2025-2029** **esbnetworksprdsastd01.blob.core.windows.net**

Enhanced Growth (EG, high)	Extensive network monitoring allows for even greater voltage reduction.	Voltage reduction is extended to 8%. By 2030, 45% of the network is covered by CVR, and 65% by 2035.

The methodology and the assumptions produced are applied to the following projects for the key years and projection over time:

Projections				
Decision paper projection	**2030**	**Scenario**	**2030**	**2035**
Turn down flexibility	0 MWh	DD, low	4.MWh (0.004%)	22 MWh (0.02 %)
		ED, mid	54 MWh (0.04%)	100 MWh (0.07 %)
		EG, high	134MWh (0.1%)	223 MWh (0.15 %)
Turn up flexibility	0 MWh	DD, low	0 MWh	0 MWh
		ED, mid	0 MWh	0 MWh
		EG, high	0 MWh	0 MWh

Trajectories or demand turn-down and demand turn-up



a

Assumed not available

b

Figure 23 Projections of flexible volume from voltage control at the grid scale for (a) turn down and (b) turn up.

Utility-scale flexibility from energy storage (ESBN flexibility)

Flexibility from the Demand Flexibility product procured by ESBN as part of the new medium term demand flexibility procurement. **Includes**: any technology able to meet the criteria for participation. **Excludes:** flexibility accounted for in other sources.

Relevant NEDS actions:

- (direct impact): 2.11 DSO flexibility procurement (ESBN) Second stage consultation on detailed aspects of product design to support medium-duration flexibility procurement tender process.

Methodology:	
Demand turn-down volume: Expected capacity * Duration of response * Expectation of availability	**Demand turn-up volume**: Expected capacity * Duration of response * Expectation of availability
Assumptions	
• Procurement will enabled new energy storage projects as well as other new demand-side response • Capacity is equivalent to charging or discharging for 4 hours. • Procurement will enable new energy storage and other demand response technology projects. • 100% of the capacity is available to deliver the flexibility services	
Limitations	
• Control strategy for the contracted assets dedicated to the ESBN flexibility service delivery	

Several aspects influence how scenarios impact the inputs to the methodology:

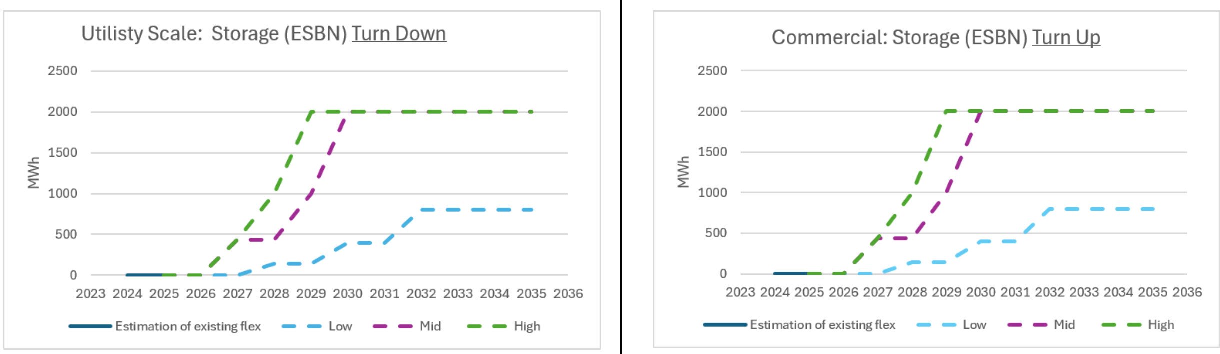
Scenarios	
Aspects that impact the volume	**Potential impact on the forecast**
Readiness of the flexibility providers to deliver projects and wider economic conditions impacting development and energisation of procured flexibility	Energisation year of the contracted capacity in each procurement phase
Interest and participation in the Demand Flexibility Product	Expected contracted capacity

Scenario	**Scenario assumptions**	**Impact**
Delayed Delivery (DD, low)	The outcome of the first procurement phase achieves lower contracted capacity and energisation longer than expected. Energisation of the projects from the accepted bids is delayed.	First round procures 35MW, which are energised in 2028, followed by additional 70MW in 2030 and finally reaching total of 200MW energised in 2032.
Expected Delivery (ED, mid)	Procurement and acceptance of bids is not significantly delayed, and energisation of projects is within the expected timeframe.	First round procures 109MW, which are energised in 2027, followed by second round with 91MW energised in 2029 and finally 500MW energised in 2030.
Enhanced Growth (EG, high)	Procurement and contracting are done in timely manner, followed by quick deployment of successful projects and consequent procurement phases	First round procures 109MW, followed by two consequent years with successful procurement and energisation, reaching total procured capacity of 500MW by 2030.

The methodology and the assumptions produced are applied to the following projects for the key years and projection over time:

Projections				
Decision paper projection	**2030**	**Scenario**	**2030**	**2035**
Turn down flexibility	16,800MWh (13.73%)	DD, low	400MWh (0.37%)	800 MWh (0.69 %)
		ED, mid	2000MWh (1.63%)	2000 MWh (1.48 %)
		EG, high	2000MWh (1.5%)	2000 MWh (1.35 %)
Turn up flexibility	16,800MWh (13.73%)	DD, low	400MWh (0.37%)	800 MWh (0.69 %)
		ED, mid	2000MWh (1.63%)	2000 MWh (1.48 %)
		EG, high	2000MWh (1.5%)	2000 MWh (1.35 %)

Trajectories or demand turn-down and demand turn-up



a b

Figure 24 Projections of flexible volume from utility scale storage procured by ESBN for (a) turn down and (b) turn up.

Utility-scale flexibility from energy storage (EirGrid flexibility)

Flexibility from the energy storage procured by EirGrid as part of the capacity market auctions and through long duration energy procurement. **Includes:** Battery energy storage procured through SEM Capacity Auctions. DS3 System services and. **Excludes:** BtM Storage and aggregated storage or DSUs.

Relevant NEDS actions:

- (direct impact): 2.5 Long Duration Energy Storage (EirGrid): Develop detailed procurement options informed by Call for Evidence responses and report to the CRU. Consultation paper to follow (Q4 2024).

Methodology:	
Demand turn-down volume: Procured capacity (CRM and DS3) * Duration of response * Expectation of availability + LDES procured volume	**Demand turn-up volume**: Assumed not available
Assumptions	
• Capacity is equivalent to charging or discharging for 2.5 hours. • Assume 85% capacity availability for CRM and DS3 • Charging rate and demand turn-up is limited to 200MW • No variation on the CRM and DS3 volumes, as they are based on the procured volumes and new procured providers are in the pipeline for construction	
Limitations	
• Additional energy storage volume is expected to be procured under CRM and DS3, but the volume is driven by the system needs and only confirmed for duration of the procurement horizon. • LDES procurement is not limited to new capacity and could include existing storage capacity	

Several aspects influence how scenarios impact the inputs to the methodology:

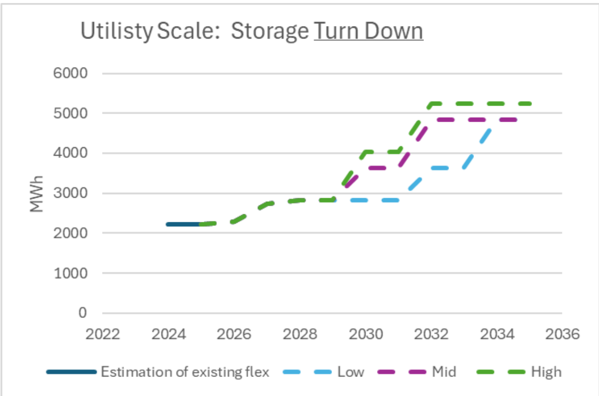
Scenarios		
Aspects that impact the volume		**Potential impact on the forecast**
LDES procurement tender analyses and review		Energisation year for the procured LDES value
LDES procurement renders interest and number of responses		Procured LDES Volume
Scenario	**Scenario assumptions**	**Impact**
Delayed Delivery (DD, low)	Minimum capacity procured under LDES is delayed by 2 years due to complexity of responses to consultation	First round of LDES (201MW) procurement is enabled by 2032 and second LDES batch comes online in 2034
Expected Delivery (ED, mid)	LDES procurement and energisation of new projects is on time for 2030	First round of LDES (201MW) procurement is enabled by 2030. Second round of LDES comes online in 2032

Enhanced Growth (EG, high)	LDES procurement and energisation of new projects is on time for 2030, and additional capacity is procured on both rounds.	First round of LDES (300MW) procurement is enabled by 2032. Second round of LDES comes online in 2032

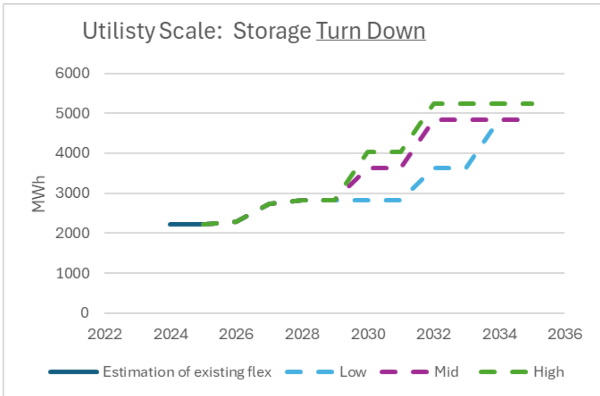
The methodology and the assumptions produced are applied to the following projects for the key years and projection over time:

Projections				
Decision paper projection	**2030**	**Scenario**	**2030**	**2035**
Turn down flexibility	16,800MWh (13.73%)	DD, low	2830 MWh (2.64%)	4835 MWh (4.13 %)
		ED, mid	3635MWh (2.97%)	4865 MWh (3.48 %)
		EG, high	4030MWh (3.03%)	5230 MWh (3.53 %)
Turn up flexibility	16,800MWh (13.73%)	DD, low	2830 MWh (2.64%)	4835 MWh (4.13 %)
		ED, mid	3635MWh (2.97%)	4865 MWh (3.48 %)
		EG, high	4030MWh (3.03%)	5230 MWh (3.53 %)

Trajectories or demand turn-down and demand turn-up



a



b

Figure 25 Projections of flexible volume from utility scale storage for (a) turn down and (b) turn up.

Utility-scale flexibility from pumped storage

Flexibility from pumped storage is provided by a cycle of charging during low-price, low-carbon periods and discharging during high-price, higher-carbon-intensity periods.

Includes: Pumped energy storage procured through SEM Capacity Auctions and DS3 System services. **Excludes:** Battery storage, commercial BtM storage, aggregated storage, hydrogen, ammonia, compressed air or flow battery energy storage.

Relevant NEDS actions:

- (direct impact): 2.5 Long Duration Energy Storage (EirGrid): Develop detailed procurement options informed by Call for Evidence responses and report to the CRU. Consultation paper to follow.

The methodology for estimating demand response volume is based on existing capacity and planned capacity from future projects, which require permitting and approval.

Methodology:	
Demand turn-down volume: estimated capacity * duration of response * participation rate	**Demand turn-up volume**: Assumed to be symmetrical to demand turn-down.
Assumptions	
• Capacity from two projects: Turlough Hill with 292MW and a future project with 296MW. • Stored volume is equivalent to charging or discharging at full rate for 4.7 hours. • Can deliver turn-down and turn-up in full capacity based on forecasted needs.	
Limitations	
• Future capacity of pumped storage only includes one project as an example. Additional projects can be added in future iterations of the estimation as they mature in their development	

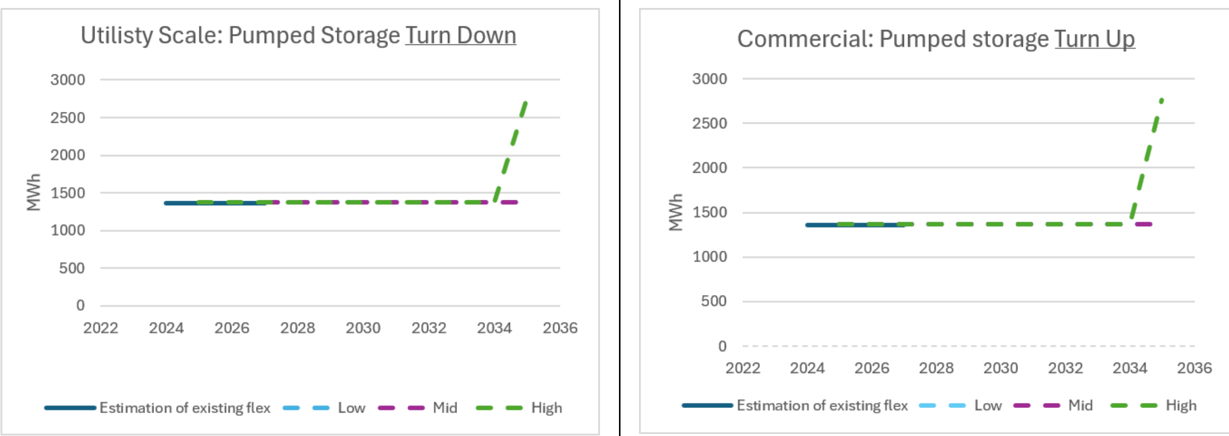
Several aspects influence how scenarios impact the inputs to the methodology:

Scenarios		
Aspects that impact the volume		**Potential impact on the forecast**
National policy and incentives for pumped storage		Capacity and duration of storage
Delay in permit granting or construction and commissioning		Year when additional storage capacity becomes available.
Scenario	**Scenario assumptions**	**Impact**
Delayed Delivery (DD, low)	No support or funding for new pumped storage projects due to uncertainty on the outcome of permit granting.	No new pumped storage capacity up to 2035. By 2030 and 2035 the total storage capacity remains to be 292MW and 4.7 hours of response duration.
Expected Delivery (ED, mid)	Project is progressing through the phases, however, construction is delayed further by 3 years compared to original timeline.	No new pumped storage capacity up to 2035.
Enhanced Growth (EG, high)	Permits are granted for new development of storage and there is sufficient funding to conclude projects. Construction and commissioning are making a good progress.	By 2035 total pumped storage capacity increases to 588MW

The methodology and the assumptions produced are applied to the following projects for the key years and projection over time:

Projections				
Decision paper projection	**2030**	**Scenario**	**2030**	**2035**
Turn down flexibility	3040 MWh (2.48%)	DD, low	1372 MWh (1.28%)	1372MWh (1.17%)
		ED, mid	1372 MWh (1.12%)	1372 MWh (1.02%)
		EG, high	1372 MWh (1.03%)	2763 MWh (1.87 %)
Turn up flexibility	3040 MWh (2.48%)	DD, low	1372 MWh (1.28%)	1372MWh (1.17%)
		ED, mid	1372 MWh (1.12%)	1372 MWh (1%)
		EG, high	1372 MWh (1.03%)	2763 MWh (1.87 %)

Trajectories or demand turn-down and demand turn-up



a b

Figure 26 Projections of flexible volume from utility-scale pumped storage for (a) turn down and (b) turn up.