



Network Needs Assessment

PR6

Commission for Regulation of Utilities (CRU)

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→ **The Power of Commitment**



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Executive summary

This Network Needs Assessment document provides an evaluation of the requirements for the energy system for the Commission for Regulation of Utilities (CRU) in Ireland. This report has been prepared to inform and complement the Draft Determinations for PR6. It does not constitute the bottom-up cost assessment, which is being undertaken separately and will be presented in separate deliverables by GHD and CEPA for the review of capex and opex, respectively. This report looks to provide an independent assessment of the infrastructure requirements, as well as an assessment of the alignment of the Network Companies' (NCs) PR6 Business Plan submissions with the headline requirements¹.

This report has been prepared based on research of national and EU policies, targets and directives, historical trends in demand and generation in Ireland, and the latest PR6 submissions by the network companies. It looks to provide a complementary analysis to supplement the detailed bottom-up assessment that will be completed to inform the recommended allowances for the Draft Determination (DD).

The analysis presented in this report highlights the significant regulatory and technical challenges from a network perspective associated with the achievement of Ireland's Net Zero ambition. This includes the need for substantial upgrades to the electricity grid to accommodate the anticipated increase in demand from the electrification of heat and transport, provision of new connections and integration of renewable energy sources, as well as to overcome existing network constraints due to underinvestment in response to financial constraints since PR3. A significant step change in investment will be required by the NCs to address the challenge, whilst also augmenting the way that investment is planned and delivered.

It should be noted that the context of significant ambition to transition to Net Zero, and the role that electricity networks will have to play to achieve this, means that there is strong consensus (in Ireland and other jurisdictions) that accelerated profiles of network investment will be observed in the short-term. The significant step increase in requested allowances can be aligned with the need to support economic growth, provide capacity headroom to overcome existing network constraints and make use of innovative solutions to make best use of assets. These in turn will support Ireland in meeting its energy targets and accelerating the net zero transition.

The NCs' business plan submissions for PR6 appear to broadly align with the forecast requirements². Overall, the load related expenditure forecasts, corresponding to net additions of assets to the system, appear to be consistent with addressing the following high-level needs:

- **Provide capacity headroom:** Proposals to provide additional network capacity, overcoming existing constraints, are key to supporting the ambition to electrify heat and transport and accommodate additional volumes of intermittent renewable generation to contribute to decarbonisation. Additionally, it is necessary to address the historic underspend in network capacity schemes that has led to lower levels of headroom capacity;
- **Facilitate economic growth:** The investments will support economic growth by enabling new connections and facilitating the expansion of housing, commercial and industrial activity. This requires new connections to be provided in a timely manner to support growth, along with sufficient supply of energy facilitated by robust planning of the network. This is essential for promoting sustainable development and protecting consumers while ensuring the electricity network can support Ireland's economic ambitions, with an expanded customer base including additional data centres.
- **Optimise existing capacity through innovation:** The investments provide an opportunity to deploy advanced grid management technologies and innovative solutions. This includes the use of flexibility services, energy storage, and smart grid technologies to enhance the efficiency and reliability of the electricity network. Embracing innovation can lead to more resilient and adaptable energy systems, capable of meeting future challenges.

¹ Ireland has committed to comply with the legally binding targets set by the EU related to its decarbonisation journey. As part of this, targets for 2030 and 2050 have been set under the Climate Action Plan, including 22GW of renewable generation installed capacity, an 80% share of electricity to be generated from renewable sources, the effective application of the Energy Efficiency First principle as part of the decision process related to energy related projects and a 51% reduction of GHG emissions by 2030 while maintaining a reliable energy system [14].

² The analysis indicates that there are some disparities between the short-term peak demand forecast (2023-2032) and the long-term forecast from 2035 onwards, which should be explained by EirGrid.

When comparing investment in the PR5 period with the PR6 proposed expenditure, the increase (increases of 131% and 347% for DSO and TSO & TAO, respectively) is higher than the forecast increase in the peak demand (9-36%, depending on the forecast scenario). However, the increases appear to be in line with the requirement to provide approximately 16,100 MVA of additional substation capacity (HV and above). This is expected to accommodate forecast demand increases, as well as to overcome existing constraints and provide capacity for connection of approximately 10 GW of contracted generation.

This Network Needs Assessment identifies areas of tension in the conclusion of the Price Control process, to support investment and contribute to meeting national ambitions whilst also considering efficiency and deliverability of proposals when setting allowances. We propose to relieve these tensions through setting moderate baseline allowances, and management of these allowances through a robust regulatory regime that provides reasonable, and proportionate, protections for consumers and enables NCs to invest (i.e. increased above baseline) on an efficient basis. This proposal is comprised of a formalised regulatory framework, with codified tools to define the expected outputs/outcomes associated with allowances, and means for scaling these allowances (principally through volume drivers and reopeners). It includes the need for enhanced reporting and monitoring, and the ability to access additional funds over and above the baseline allowances with relative ease in order to avoid introducing further barriers to delivery.

To ensure the successful implementation of the proposed investments, key considerations for the PR6 regulatory framework to be implemented may be characterised as follows:

- **Realistic Allowances:** Set allowances that align with realistic delivery programmes, allowing for defined and monitored progress, and release additional funding as work progresses.
- **Adaptable Mechanisms:** Implement volume drivers and reopeners to adjust allowances based on actual demand and generation levels, ensuring investments can be scaled as needed.
- **Performance Monitoring:** Establish robust reporting and monitoring systems to track investment progress and impact, with regular updates on project status and performance metrics. Ensure transparency while avoiding overly burdensome requirements to allow NCs to proceed efficiently.
- **Stakeholder Involvement:** Engage stakeholders in the regulatory process through regular consultations with network companies, policymakers, and consumers to gather feedback and make informed decisions.

The findings of this Network Needs Assessment, which chime with similar findings from the recent UK NIC report on 'Electricity distribution networks: Creating capacity for the future'³, support the approach to acknowledge the level of uncertainty and need for substantial investment in providing determinations for PR6. However, there should be a strong focus on ensuring the required outputs are delivered, which will be supported by defining and monitoring specific delivery obligations associated with baseline allowances and mechanisms for providing access to additional funding through the regulatory framework within PR6.

This report is subject to, and must be read in conjunction with, the limitations set out in section 1 and the assumptions and qualifications contained throughout the Report.

³ <https://nic.org.uk/studies-reports/electricity-distribution-networks-report/>

Contents

Executive summary	iii
1 Introduction	9
1.1 Network Needs Assessment	9
1.2 Role as part of the Price Control	9
1.3 Net Zero	11
1.4 EU Context	11
1.5 Irish Context	12
2 Impact on the Electricity System	14
2.1 Overview of Impact	14
2.1.1 Generation	15
2.1.2 Transmission Network	15
2.1.3 Distribution Network	16
2.1.4 TSO – DSO Coordination	16
2.2 Challenges	17
2.2.1 Policy and Regulatory	17
2.2.2 Technical	18
2.2.3 Procurement, skills and consumers	20
2.3 Examples from Other Countries	20
3 Flexibility Services	22
3.1 Flexibility Markets	22
3.2 Energy Storage Solutions (ESS)	22
3.2.1 Battery Energy Storage Solutions (BESS)	23
3.2.2 Pumped Hydro Storage (PHS)	24
3.3 Demand Side Response	24
4 Data and Digitalisation	26
4.1 Open access data	26
4.2 Cybersecurity	26
4.3 User-friendly Interface	27
4.4 Seamless integration with HEMS	27
5 Electricity Supply and Demand in Ireland	28
5.1 Electricity Generation	28
5.2 Renewable Generation Targets	28
5.2.1 Solar PV	29
5.2.2 Onshore Wind Energy	31
5.2.3 Offshore Wind Energy	32
5.3 Electricity Demand	33
5.3.1 Peak Demand	34
5.3.2 Electrification of Heat	35
5.3.3 Electrification of Transport	36
5.3.4 Data Centres	37
6 Assessment of the Network Company Business Plan Submissions for PR6	38
6.1 System Peak Demand	38

6.2	Generation Capacity	42
6.3	Network Capacity	45
6.3.1	Substation Capacity in Ireland	45
6.3.2	Capacity Headroom	46
6.3.3	Constraints and Curtailments	47
6.3.4	Underinvestment in Previous Periods	49
6.4	Load-related Investment Proposals	50
6.5	Innovation and Research and Development (R&D)	52
6.6	Resource and Deliverability	53
7	Delivering Investment Efficiently in PR6	55
7.1	Strategic Planning and Investment	55
7.1.1	Considerations for a Robust CBA	57
7.2	Energy Efficiency First Principle	58
7.3	European Regulatory Frameworks	59
7.4	Other Considerations for the PR6 Regulatory Framework	61
8	Conclusion	63
9	Bibliography	65
Appendix A	Proposed asset volumes	71
A-1	Proposed asset volumes	72
A-1-1	TAO Asset Investments	72
A-1-2	DSO Asset Investments	75

Table index

Table 5.1	Current and projected offshore wind capacity	32
Table 6.1	Mapping of network characteristics to associated infrastructure parameters	38
Table 6.2	TSO and DSO connected and contracted generation capacity by type (MW)	43
Table 6.3	TSO and DSO connected and contracted generation capacity by connection voltage (MW)	44
Table 6.4	Comparison of PR5-PR6 load-related investments	50
Table 6.5	ESB Networks Innovation Focus for PR6	52
Table 7.1	Mapping of existing infrastructure efficiency-related incentives in Europe applied to transmission	60

Figure index

Figure 1.1	Illustration of the role of long-term forecasting and outturn over Price Controls	10
Figure 1.2	Decarbonisation targets of Ireland	13
Figure 2.1	Evolving energy network landscape	15
Figure 3.1	Uses of FTM BESS	23
Figure 5.1	Electricity generation mix in Ireland as percentage of demand in 2023	28
Figure 5.2	RES share in electricity generation in Ireland [50]	29
Figure 5.3	Renewable energy capacity targets by source in Ireland	29

Figure 5.4	Year-to-year change in solar PV installations in Ireland	30
Figure 5.5	Solar PV installed capacity and projections in Ireland based on the WEM and WAM scenarios	31
Figure 5.6	Onshore wind installed capacity and projections in Ireland	31
Figure 5.7	RESS auction results in Ireland	32
Figure 5.8	Annual total demand (TWh) in Ireland [50]	33
Figure 5.9	Weather corrected annual system peak demand (MW) in Ireland [50]	34
Figure 5.10	Transmission-connected customers' total demand [TSO data]	35
Figure 5.11	Electrification of heating in Ireland key figures	36
Figure 5.12	Electrification of transport in Ireland key figures [70]	36
Figure 5.13	Data centres' power consumption in Ireland	37
Figure 6.1	Comparison of System Peak Demand data from PR6 BPQs and other sources	39
Figure 6.2	Comparison of short- and long-term forecasts of peak demand from GCS23 and TES23, respectively	40
Figure 6.3	Make -up of short term peak demand forecast	40
Figure 6.4	PR5-6 actual and forecast annual NNLC connection volumes	41
Figure 6.5	Distribution HV-connected customers' consumption	42
Figure 6.6	Distribution LV and MV-connected customers' consumption	42
Figure 6.7	TSO and DSO connected and contracted generation capacity by type (MW) [connected: 14.5 GW; contracted: 10.2 GW]	43
Figure 6.8	TSO and DSO connected and contracted generation capacity by connection voltage (MW) [connected: 14.5 GW; contracted: 10.2 GW]	43
Figure 6.9	Generation capacity headroom 2025 and 2030	44
Figure 6.10	TSO and DSO installed transformer capacity (MVA) [TSO: 16,111 MVA; DSO: 28,777 MVA] [74] [75]	45
Figure 6.11	TSO and DSO installed transformer capacity and PR6 proposed capacity additions (MVA) [TSO additions: 12,077 MVA; DSO additions: 3,999 MVA]	46
Figure 6.12	ESB Networks scenarios headroom capacity: available firm demand capacity (MVA) – best view scenario [76]	47
Figure 6.13	Dispatch down volumes 2023-24 [78]	48
Figure 6.14	EirGrid Dispatch Down Summary Report - Daily 2024 IE wind dispatch down (constraints and curtailment) volume chart	48
Figure 6.15	EirGrid Dispatch Down Summary Report - Daily 2024 IE solar dispatch down (constraints and curtailment) volume chart	49
Figure 6.16	PR3 re-profiled capex investment programme	50
Figure 6.17	Comparison of PR5-PR6 DSO Load-related Capex	51
Figure 6.18	Comparison of PR5-PR6 TSO and TAO Load-related Capex	51
Figure 7.1	Illustration of steps for strategic network planning	56
Figure A- 1	Comparison of TAO asset volumes PR5-6	72
Figure A- 2	TAO Overhead lines: actual and planned investments	73
Figure A- 3	TAO Underground cables: actual and planned investments	73
Figure A- 4	TAO Transformers: actual and planned investments	74
Figure A- 5	TAO Switchgear: actual and planned investments	74
Figure A- 6	Comparison of DSO asset volumes PR5-6	75
Figure A- 7	DSO Overhead lines: actual and planned investments	76
Figure A- 8	DSO Underground cables: actual and planned investments	76
Figure A- 9	DSO Transformers: actual and planned investments	77
Figure A1- 1	DSO Switchgear: actual and planned investments	77
Figure A- 10	DSO Substation civil works: actual and planned investments	78

Appendices

Appendix A Proposed asset volumes

1 Introduction

1.1 Network Needs Assessment

This report presents a Needs Assessment for the requirements for the energy system for the Commission for Regulation of Utilities (CRU) in Ireland. This report is being prepared to inform and complement the Draft Determinations for PR6. This report does not constitute the bottom-up cost assessment, which is being undertaken separately and will be presented in separate deliverables by GHD and CEPA for the review of capex and opex, respectively. This report looks to provide an independent assessment of the infrastructure requirements, as well as an assessment of the alignment of the Network Companies' (NCs) PR6 Business Plan submissions with the headline requirements⁴. The analysis highlights the significant regulatory and technical challenges from a network perspective associated with the achievement of Ireland's Net Zero ambition. The identified key issues include the need for substantial upgrades to the electricity grid to accommodate the anticipated increase in demand from the electrification of heat and transport, provision of new connections and integration of renewable energy sources. The report has been prepared based on research of national and EU policies, targets and directives, historic trends in demand and generation in Ireland, and the latest PR6 submissions by the network companies. It looks to provide a complementary analysis to supplement the detailed bottom-up assessment that will be completed to inform the recommended allowances for the Draft Determination (DD).

This report is structured as follows:

- Sections 1.2-1.5 present further details of the context of the Net Zero transition, covering the EU and Ireland;
- Section 2 provides an overview of the considerations related to the impact of the Net Zero transition on the different parts of the electricity system;
- Section 3 presents details of the role of flexibility services as part of the energy system;
- Section 4 presents details of the role of data and digitalisation;
- Section 5 presents quantified details of the changes in electricity supply and demand in Ireland;
- Section 6 presents our assessment of the Network Company Business Plan submissions for PR6;
- Section 7 presents a discussion on delivering investment efficiently; and
- Section 8 presents our conclusions.

1.2 Role as part of the Price Control

This Network Needs Assessment documents the conclusions of a top-down assessment of need, which has been carried out as a separate exercise from the bottom-up cost assessment. It is intended to contribute to the evidence provided to CRU, and inform the recommendations from the bottom-up work for setting allowances in the DD.

Figure 1.1 presents an illustration of the role of long-term forecasting and outturn over Price Controls. This image is purely illustrative rather than reflective of any submissions from NCs as part of PR6. However, it shows the effect of having to rely on uncertain forecast data, whether it be technical parameters related to demand, network assets (volumes, etc) or investment. It is reasonable to consider a range of scenarios, which EirGrid has done in its sector publications, and ultimately used to inform the Business Plan submissions.

In general terms, there is a tendency for forecasts by system operators to over-estimate the increases expected to be observed in the short-term (including the common expectation of an impending step change). This could be described as following a conservative approach to 'plan for the worst', but also risks customers footing the bill for investment in infrastructure before it is strictly required. This is illustrated in the figure with the indicative ex ante

⁴ Ireland has committed to comply with the legally binding targets set by the EU related to its decarbonisation journey. As part of this, targets for 2030 and 2050 have been set under the Climate Action Plan, including 22GW of renewable generation installed capacity, an 80% share of electricity to be generated from renewable sources, the effective application of the Energy Efficiency First principle as part of the decision process related to energy related projects and a 51% reduction of GHG emissions by 2030 while maintaining a reliable energy system [14].

PR5 forecast shown at the top of the forecast range for the period, with a hypothetical outturn towards the bottom of the forecast range.

Moving into PR6, a revised forecast range is illustrated from the updated starting point, with a similar ex ante forecast for PR6 (two lines representing different scenarios, such as “unconstrained” and “constrained/deliverable”). It can be seen that the top of the PR6+ forecast range reaches the same level as the top of the original PR5+ forecast range, subject to a delay. This is typically observed, with performance against targets “slipping” back in time due to delays in delivery. Similarly, the hypothetical ex ante outturn for PR6 is illustrated as falling in the middle of the forecast range. Two profiles are shown for the outturn, including a “steady increase” and a “hockey stick” type profile with a step at the end of the period.

It should be noted that the context of significant ambition to transition to Net Zero, and the role that electricity networks will have to play to achieve this, means that there is strong consensus (in Ireland and other jurisdictions) that accelerated profiles of investment will be observed in the short-term. However, this emphasises the importance of managing the delivery to sustainable levels, such that extreme step increases can be avoided.

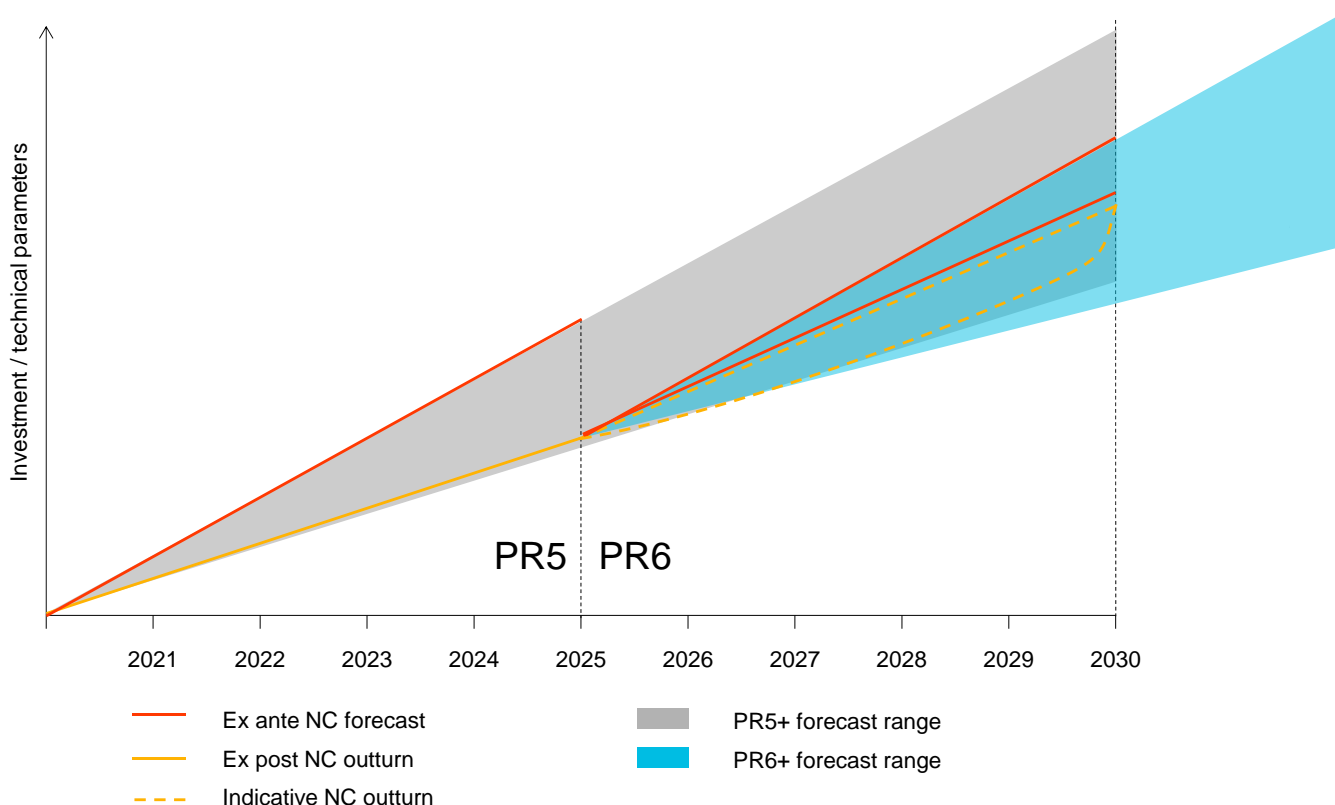


Figure 1.1 Illustration of the role of long-term forecasting and outturn over Price Controls

This Network Needs Assessment report identifies the tension in concluding the Price Control process:

- As part of a prudent bottom-up cost assessment, it would generally be expected to apply an efficiency challenge to the PR6 forecast values presented by the network companies, assess the deliverability of the proposals, and review of historical performance (and acknowledging forecast uncertainty); however,
- In the context of the needs identified for the sector to contribute to supporting national ambitions, including at the pace required, it would be reasonable to recommend allowances to increase towards the more optimistic projections.

We propose that this tension is overcome through setting moderate baseline allowances, and that these are managed through a robust regulatory regime that provides reasonable, and proportionate, protections for consumers while enabling NCs to invest to the required extent (i.e. increased above baseline) on an efficient basis. The existence of this tension supports the need for enhanced reporting and monitoring, and the ability to access additional funds over and above the baseline allowances with relative ease to avoid introducing further barriers to delivery. This is in line with our proposals to introduce a formalised regulatory framework, with codified

tools to define the expected outputs/outcomes associated with allowances, and means for scaling these allowances (principally through volume drivers and reopener).

1.3 Net Zero

The pursuit of Net Zero has become a pivotal objective in the global effort to combat climate change. This concept is central to international climate policies, particularly following the 2015 Paris Agreement, which aims to limit global temperature rise to well below 2°C above pre-industrial levels, with efforts to limit the increase to 1.5°C [1].

The urgency of meeting Net Zero was underscored at the COP26 summit in Glasgow, where nearly 200 countries adopted the Glasgow Climate Pact, emphasising the need for immediate and sustained initiatives to reduce global Greenhouse Gas (GHG) emissions by at least 55% by 2030 and to reach carbon neutrality by around 2050 [2].

The transition required for nations to attain these targets extends beyond the offset of GHG emissions, necessitating a comprehensive transformation of energy systems, industrial processes, and societal behaviours. The energy sector is particularly critical, as it accounts for a significant portion of the global GHG emissions. In 2023, energy-related CO₂ emissions worldwide increased by 1.1% to exceed 40 billion metric tons, highlighting the urgent need for decarbonisation [3]. For this to be achieved, a holistic approach to energy system transformations, encompassing financial incentives, policy frameworks, and the creation of resilient energy infrastructures is vital.

The progression to a carbon-neutral energy system heavily relies on the wide deployment of Low Carbon Technologies (LCTs), including renewable energy sources, energy storage, flexibility, energy efficiency measures, and innovative solutions such as Carbon Capture, Usage and Storage (CCUS). These integrations are crucial in ensuring a reliable and sustainable energy supply while reducing emissions and supporting economic growth. Notably, renewable energy sources are set to play a key role in the progression towards carbon neutrality with the share of renewables in global electricity generation forecasted to expand from 30% in 2023 to 46% by 2030 [4].

1.4 EU Context

The European Union (EU) aims to achieve Net Zero emissions by 2050, a primary objective of the European Green Deal, which outlines a strategy for transforming the economy to be climate-neutral by 2050 while ensuring sustainable growth and social equity [5].

The EU's climate targets are structured around key milestones for 2030, 2040, and 2050. By 2030, the EU aims to reduce net GHG emissions by at least 55% compared to 1990 levels, a target enclosed in the "Fit for 55" package, which includes a series of legislative proposals to align EU policies with these new climate goals. Following this, the 2040 interim goal seeks to achieve a 90% net emissions reduction leading to Net Zero in 2050.

The energy sector plays a pivotal role in the EU's transition to Net Zero, as it is responsible for a significant portion of its GHG emissions. As such, efforts have been made to decrease emissions in the energy sector. In 2023, emissions from power and industry installations totalled 1095.9 MtCO₂-eq, a 16.5% reduction compared to the 2022 levels and marking the highest year-to-year reduction to date [6]. One of the key drivers of this decrease is the continuously growing share of renewable energy in the EU's energy mix, which in the past year accounted for 44.7% of electricity production. Additionally, the EU's total energy consumption has been on a declining trend, with primary energy consumption reaching 1,210 million tonnes of oil equivalent (Mtoe) in 2023, down from 1,500 Mtoe in 2010 with 24.5% of the total energy consumption covered by renewable energy [7] [8].

To continue this progress and meet the ultimate goal of Net Zero, the EU has set key objectives in the energy sector by substantially expanding the share of renewables in the energy mix, increasing the previous target of 32% renewables by 2030 to at least 42.5% [9]. To accommodate these plans, the enhancement of the energy system's flexibility is considered crucial for the integration of LCTs, which involves investments in smart grid infrastructure, energy storage solutions, and demand side response mechanisms. Promoting energy efficiency is another critical measure, with efforts made to improve energy efficiency across the power system, buildings, industry, and transportation, thereby reducing overall energy demand.

Several key directives and policies underpin the EU's strategy to achieve these objectives while ensuring grid resilience and final consumer protection. These include:

- The European Climate Law which makes the 2050 carbon neutrality target legally binding for all its State Members and sets the framework for achieving it, including mechanisms for monitoring progress and adjusting policies as needed [10].
- The revised Renewable Energy Directive (RED III) which sets binding targets for the share of renewable energy in the EU's energy mix, aiming for at least 42.5% by 2030.
- The Energy Efficiency Directive (EED) which establishes measures to improve energy efficiency across the EU, targeting a 32.5% reduction in energy consumption by 2030. It plays a significant role in promoting demand-side response and flexibility, ensuring optimised energy consumption and grid stability to handle renewable energy variability [11]. The EED sets guidelines for policymakers, regulators, and network operators, outlining their roles in achieving energy efficiency goals. Additionally, it addresses energy poverty by ensuring that energy efficiency measures benefit all citizens, particularly those in vulnerable situations.
- The Emissions Trading System (ETS) which is a cornerstone of the EU's climate policy, capping emissions from power plants, industrial facilities, and aviation, and aims to reduce emissions from these sectors by 62% by 2030 compared to 2005 levels [12].

1.5 Irish Context

Ireland is committed to achieving Net Zero emissions by 2050, in line with the EU's broader climate goals. This commitment is outlined in the Climate Action and Low Carbon Development (Amendment) Act 2021, which sets a legally binding path to Net Zero emissions by 2050 and aims for a 51% reduction in emissions by 2030 compared to 2018 levels [13]. The Climate Action Plan 2024 (CAP24) builds on this framework, providing a detailed roadmap for halving emissions by 2030 and meeting the Net Zero target outlining sector-specific carbon budgets and emissions ceilings [14].

The country has made significant strides in renewable energy deployment, yet it remains heavily reliant on fossil fuels. As of 2023, fossil fuels accounted for 82.6% of Ireland's primary energy needs [15]. This reliance is particularly distinct in the transport and heating sectors, where fossil fuels dominate. CAP24 has emphasised the importance of renewable energy, energy efficiency, and low-carbon technologies (LCTs). For instance, Ireland aims to generate 80% of its electricity from renewable sources (RES-E) by 2030, significantly increasing its wind and solar power capacity.

Additionally, the REPowerEU amendment of June 2024 has allocated 50.2% of Ireland's recovery and resilience plan to climate objectives [16]. Ireland's updated National Energy and Climate Plan (NECP), submitted in December 2023, outlines further necessary steps to meet these targets.

The Sustainable Energy Authority of Ireland (SEAI) plays a crucial role in the transition towards carbon neutrality, providing expertise, funding, and policy advice to support the deployment of renewable energy and energy efficiency measures. The SEAI's National Energy Projections 2024 report highlights that while progress has been made, significant challenges remain. Achieving the targets will require scaling up efforts on both energy efficiency and renewable energy deployment [17].

In terms of energy demand, Ireland's total energy demand saw a 0.8% increase in 2023, driven mainly by higher energy demand in the transport sector. However, total energy-related emissions marked their lowest level in the last 30 years decreasing by 8.3%. Additionally, electricity-related emissions decreased by 22%. This progress is attributed to increased renewable energy use and improved energy efficiency in accordance with EED.

Wind energy, an essential part of Ireland's renewable strategy, generated 11.7 TWh in 2023, giving Ireland one of the highest shares of wind energy in electricity generation among IEA member countries. Additionally, solar energy generation capacity increased by 0.53GW in 2023, driven by utility-scale solar farms [18].

Interconnectors also serve a critical part in Ireland's energy system, enhancing energy security by allowing electricity imports during high demand and supporting renewable energy integration by exporting excess wind power. They promote market efficiency, lower consumer prices, and aid in decarbonisation by enabling the import of low-carbon electricity. Additionally, interconnectors serve an important role in grid stability, balancing supply and demand across a larger area, which is crucial as renewable energy sources increase. The Greenlink interconnector became operational in 2025, providing a 500MW capacity link between Great Island substation (Co.

Wexford) and Pembroke substation in South Wales. This supplements the 500MW capacity of the East West Interconnector (EWIC), which has been operational since December 2012, and provides capacity for the intraday auctions between SEM and GB (following Brexit)⁵.

For Ireland to be able to meet the decarbonisation targets set in CAP24, presented in Figure 1.2, it is recognised that significant grid improvements are required. As such, the installed renewable generation capacity will be increasing over the coming years, especially that of offshore wind. The national grid infrastructure will need to further expand and modernise to be adequately prepared for balancing the variable nature of renewable generators and the amplified future electricity demand. Additionally, smart technologies and flexibility mechanisms will need to be adopted at a higher pace for the enhancement of the grid’s reliability and resilience. Thus, strategic network planning is placed at the core of Ireland’s Net-Zero journey.

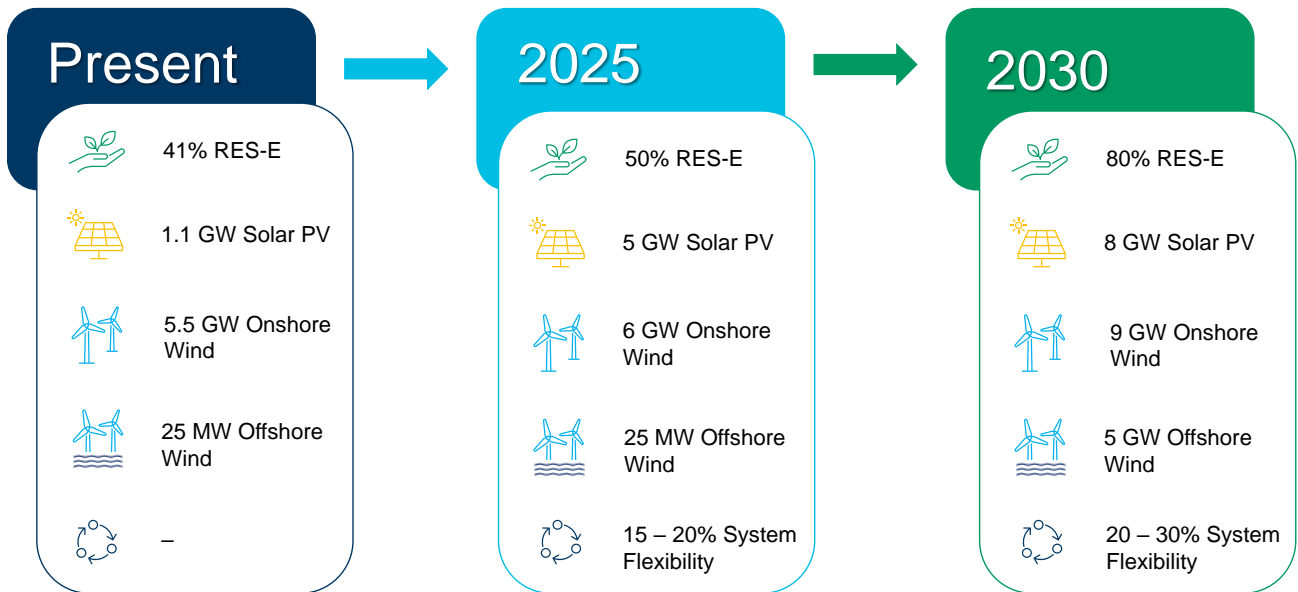


Figure 1.2 Decarbonisation targets of Ireland

⁵ Eirgrid states that the ‘SEM Committee have completed a consultation on the cross-border trading arrangements’

2 Impact on the Electricity System

The transition to Net Zero is fundamentally dependent on the decarbonisation of the energy sector, primarily driven by the adoption of LCTs and increased renewable generation. This necessitates the energy system to adapt to the evolving landscape. As traditional power systems rapidly shift towards a decentralized and digitalized energy model, the roles and significance of network owners and operators are evolving, necessitating the enhancement and expansion of the network. Proper timing and planning of the required investments are crucial to ensure that the network does not become a barrier to achieving net zero, while also protecting the interests of consumers who will ultimately fund these investments. Network owners and operators must accomplish this while fulfilling their statutory obligations to ensure that the network remains safe, reliable, and resilient.

This section provides an overview of the considerations related to the impact of the Net Zero transition on the different parts of the electricity system, including:

- Overview of the impact on generation, transmission and distribution networks, and TSO-DSO coordination, in section 2.1;
- Associated challenges in section 2.2; and
- Examples of initiatives to address policy challenges in other regions in section 2.3.

2.1 Overview of Impact

The decentralisation and digitalisation of the electricity system is transforming the energy landscape in significant ways. This transformation is primarily driven by the increasing integration of renewable generation into the energy mix at both large and small scales. Moreover, electrification of transport and heat will result in a significant uptake of electric vehicles and heat pumps, amplifying the system's electricity demand. This increase in demand across a more dispersed and dynamic network is driving the need for greater grid flexibility and capacity. Significant upgrades to infrastructure and smart grid technologies will be required to ensure the network is fit for purpose now and into the future.

As part of this transition, network operators will experience significant challenges and opportunities to accommodate the shift in demand levels, increased renewable generation and requirements for the achievement of national Net Zero targets. Thus, network operators should be prepared to exploit new technologies and manage the complexities of integrating distributed energy resources (DERs) while ensuring grid stability and a resilient energy supply. This could potentially be achieved through advanced mechanisms such as flexibility services, demand-side response (DSR), and the grid-wide adoption of energy storage. As such, Transmission System Operators (TSOs) and Distribution System Operators (DSOs) are being introduced to new responsibilities into their individual roles, while accounting for these into their refined network planning procedures.

Figure 2.1 provides an overview of the energy landscape and how it is evolving in the decarbonisation transition.

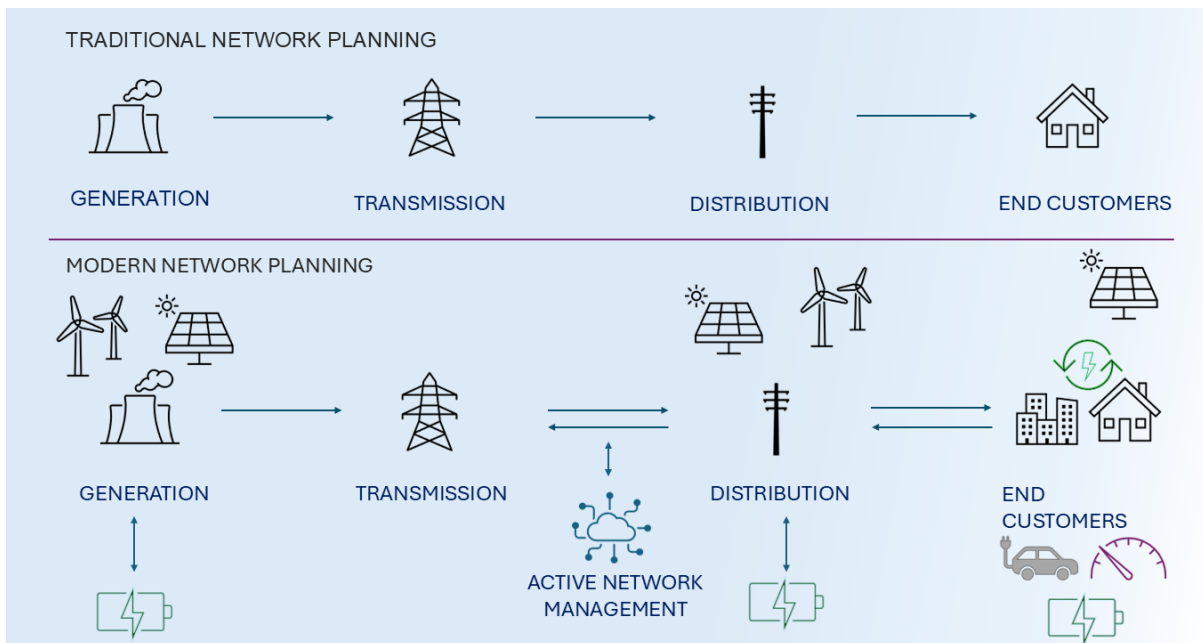


Figure 2.1 Evolving energy network landscape

2.1.1 Generation

Transmission-connected generation has undergone significant changes over the years, transitioning away from large, centralised plants powered by fossil fuels, towards more dynamic and dispersed renewable energy sources. Traditionally, power generation relied heavily on coal, natural gas, and nuclear plants, which provided a stable and predictable supply of electricity. However, the shift towards less carbon intensive generation has resulted in a significant increase in renewable energy sources such as wind and solar.

One of the key technical challenges associated with the shift to renewable energy is the impact on grid inertia. Inertia, provided by the rotating mass of large generators in traditional power plants, helps to stabilise the grid during disturbances and ensure minimal loss of supply. Renewable energy sources that replace the traditional technologies have lower inherent inertia, resulting in the potential for the network to become more susceptible to frequency fluctuations and instability.

Batteries and interconnectors play a crucial role in supporting the energy supply of the network. Battery energy storage systems can provide fast-acting frequency response and reserve capacity, helping to balance supply and demand and maintain grid stability. Interconnectors, which link different regional grids, enable the sharing of electricity across borders, enhancing the overall resilience and flexibility of the power system.

2.1.2 Transmission Network

Historically, TSOs have relied on controllable, large-scale generators to provide energy and system balancing. This model primarily depended on substantial investments in transmission infrastructure to meet predictable demand patterns and maintain a stable generation mix dominated by fossil fuels. The planning process was relatively straightforward, focusing on ensuring reliable electricity delivery from large centralised power plants to consumers.

The push towards the electrification is driving a rapidly evolving landscape characterised by several significant challenges. As centralised generators are phased out, TSOs must increasingly depend on and accommodate the integration of intermittent decentralised renewable energy sources, such as wind and solar.

These energy sources introduce further variability and unpredictability into the grid, necessitating advanced strategies for maintaining stability and resilience. Additionally, the electrification of several sectors, such as transportation and heating, will lead to a significant increase in electricity demand and final consumption. This shift in generation and demand patterns introduces potential congestion and unscheduled power flows, adding complications in transmission network management.

2.1.3 Distribution Network

Traditionally, DSOs have played a crucial role in the passive management of electricity distribution networks. Their primary responsibilities included ensuring the safe and reliable transportation of electricity from the transmission network to end consumers.

As we transition towards a net-zero future, the role of DSOs is evolving significantly. The uptake of LCTs like rooftop solar panels, community wind projects, and EVs is transforming DSOs from passive managers to active operators of the distribution network.

This integration has changed the distribution network paradigm, introducing higher uncertainty and bidirectional power flows. These changes impose new challenges to ensure efficient and secure grid operation, including the injection of distribution generation surplus from the distributed generation to the transmission grid.

This shift requires DSOs to deploy smart grid technologies that enable real-time monitoring and control of the network, facilitating the balance of supply and demand more effectively.

Specifically in Ireland, besides the uptake of LCTs, electricity demand is set to further increase at the Low Voltage (LV) level due to the “Housing for All” government initiative. This programme aims to deliver new affordable homes (multi development houses, one off houses and private apartments) and social housing to tackle homelessness and issues that have arisen in the residential sector. Since the initiation of the programme in 2021, approximately 74,000 new houses have been built (up to Q2 2024 data) [19]. During the first three months of 2024, 32,000 new houses were completed and 38,000 were granted planning permission. The continuous annual growth of these developments will lead to increased customer connections and higher levels of electricity demand in large towns such as Galway, Cork and Dublin, necessitating further enhancements to infrastructure and capacity to ensure a reliable supply.

In addition to these technical responsibilities, DSOs have a crucial role in consumer protection with the regulator ensuring fair competition and the safeguarding of consumer rights. This includes maintaining a reliable and resilient electricity supply, preventing and responding to faults, and ensuring that the costs of network upgrades are managed efficiently to avoid undue financial burden on consumers.

2.1.4 TSO – DSO Coordination

DSOs face the challenge of managing peak loads and mitigating network congestion. With more decentralised generation sources, there is a need for enhanced coordination between DSOs and TSOs to plan upgrades to the system, provide reactive power support and maintain voltage stability. This requires investment in advanced grid management technologies and fostering collaboration with consumers and other stakeholders to optimise energy use and enhance the resilience of the distribution network.

Effective coordination between TSOs and DSOs is essential for maintaining grid stability, managing congestion, and ensuring cost-effective operations. By working together, TSOs and DSOs can make better use of flexibility services, such as demand response and DERs, leading to more efficient grid operations. Enhanced flexibility, real-time data sharing, and new regulatory frameworks will be necessary to manage variable generation and consumption patterns. This coordination will be crucial for integrating RES, enhancing grid flexibility, and supporting real-time responses to changes in the grid.

In Ireland, the Joint System Operator Programme (JSOP) was launched in 2021 to secure the collaboration between EirGrid (the TSO) and ESB Networks (the DSO) [20]. This initiative aims to address the evolving needs of the electricity system and deliver integrated solutions. The JSOP has achieved significant milestones, such as reducing dispatch down and curtailment, particularly in the Dublin region, and developing streamlined processes for integrating new technologies into the grid. Additionally, through this programme the system operators are developing advanced grid management technologies and models to increase the system’s flexibility and ensure its stability.

2.2 Challenges

The energy system has already seen significant change in response to addressing climate change through decarbonisation. This change is forecast to accelerate through continued electrification of heat, transport and industry. In addition, adoption of cleaner energy sources will see a dramatic increase in the connection of solar, onshore wind, offshore wind and other LCTs.

The electricity system in Ireland has also experienced these changes and will also be subjected to the rapid transition. The targets mentioned previously in section 1.5 are driving the plans to invest in infrastructure, however, these are not completely static as the policy landscape is changing dynamically with changes to the economy and recent global events affecting energy security. Furthermore, investment across the energy industry is under scrutiny, with regulators and government bodies aware that consumers will be funding the transition, especially during the current cost of living crisis.

Uncertainty associated with regulatory changes, technological advancements, and market dynamics, will undoubtedly impact and inform long-term planning and investment decisions. Additionally, supply chain disruptions, intensified by global events and the rising demand for renewable energy technologies, pose significant risks to the timely deployment of essential infrastructure. Furthermore, the transition necessitates a skilled workforce capable of managing and maintaining advanced energy systems. However, there is a significant skills gap in the energy sector, making the attraction and retention of qualified personnel a critical task.

Whilst there is uncertainty around the exact scale and timing of investment, it is recognised that a significant step change will be required to deliver a net zero over the coming decades. Energy companies are also being challenged to ensure that they maximise their existing assets and exploit the latest technology to defer or mitigate the need for major reinforcement.

2.2.1 Policy and Regulatory

With the privatisation and liberalisation of energy markets in recent years, much of the focus of network regulation has been on driving down costs and increasing efficiency. However, in some regions, these regulatory structures are being adapted to explicitly incentivise investments that support the energy transition. Regulatory systems are expected to encourage grid expansion and the integration of unconventional solutions. Effective application of incentives to boost investments in smart solutions remains a significant challenge for regulators. Key issues include increasing renewable energy integration, managing curtailment and its compensation, and enhancing security without escalating planning costs for consumers. These challenges necessitate a systemic approach to regulation and policymaking, which is further complicated by the urgency of the transition.

Typically, network companies undertake upgrades and other investments in response to clearly identified needs. However, regulators are increasingly encouraging anticipatory investments, or "investing ahead of need," to prevent delays in investments on both the supply and demand sides.

Additionally, new technologies that link multiple vectors present regulatory and legislative challenges. These include defining the process (storage or production), determining incentives and exemptions, managing related costs to final consumers, and addressing licensing, connection, capacity constraints, and unbundling rules.

While solutions to many of these challenges exist, their effective implementation is often hindered by associated political and social issues. For example, incentivising unconventional measures like storage and other flexibility services alter how capital and operational expenses are treated within the regulatory framework. Unconventional measures typically have higher operational costs compared to more capital-intensive grid expansion solutions, making it difficult to incentivise them under systems that reward capital investment.

Network regulators must also be adaptable and responsive to manage increased uncertainty from the net zero transition and attract investment, while avoiding the overbuilding of networks. As natural monopolies, energy networks are regulated businesses, and their revenues depend on tariffs decided by national regulatory authorities. The transition to net zero is not a linear path, and regulators that want to attract the necessary investment to better manage change and risk will need to be dynamic, responsive, and adaptable. This includes performing periodic price control reviews to gather information on demand, costs, and energy losses, and setting regulatory parameters that remain relatively stable for several years.

Moreover, the integration of DERs into the electricity markets and system operation services faces several policy barriers. These barriers include difficulties in accessing markets, lack of national rules, and retail electricity prices that do not send proper price signals. A proper legal framework is needed to allow new actors to enter the electricity markets and provide services to grid operators. This includes addressing restrictive requirements, limited competition in the retail market, and public interventions that fix retail electricity prices.

Similar to the challenges faced by various electricity regulators across Europe, the CRU also encounters difficulties in regulating the electricity sector. The PR6 price control period will be particularly crucial in the pursuit of net zero, as it extends until 2030, aligning with the target established in the Climate Action and Low Carbon Development (Amendment) Act 2021. The overall framework for PR6 (comprising baseline allowances, along with mechanisms to access additional funds) is proposed to be adaptable to the complex and non-linear path towards decarbonisation.

2.2.2 Technical

The transition to a Net Zero energy system introduces several technical challenges in transmission and distribution network planning. TSOs will prioritise safety and reliability when transmitting, operating, planning, and balancing power from large-scale generation facilities to large third-party consumers and DSOs. DSOs, on the other hand, are responsible for managing DER integration, congestion, and voltage regulation, as well as the efficient and high-quality transmission of energy from the HV grid to end users. Some of the key technical challenges they face are:

– Network Capacity

One of the main challenges is ensuring that there is sufficient network capacity available to accommodate the forecast increase in both demand and generation. Demand is expected to increase by approximately 50% by 2030, whilst renewable generation is set to reach 22GW. Both load and generation profiles will also change over time and be more dynamic in nature due to the technologies connecting to the network. Whilst network operators will seek to deploy novel methods to accommodate these increases, such as smart charging, dynamic ratings and flexibility, it is clear that significant investment in new infrastructure will be required. This new infrastructure will include both extension of assets to facilitate the connection to the main network but also the upgrade and installation of new assets to create additional capacity. Some of these costs will be directly recoverable by the network operators from newly connected parties, however, the majority of reinforcement costs will be recovered from consumers in line with the current approach.

– Data and Digitalisation

Delivery of Net Zero will also require consumers, industry and operators to maximise the use of existing and new technologies. The use of energy storage, flexibility and smart monitoring/data systems will need to be coordinated effectively to exploit the full potential of the assets. Actively managing these technologies and systems across all voltage levels will require network companies to maximise the use of existing data, install more monitoring and implement new software that harness the latest algorithms and controls. In addition, these new approaches can also be used to better inform short-, medium- and long-term decisions relating to energy forecasts, dispatch and control. The data generated from the new monitors and systems should also be shared with academia and industry who are actively working on the next generation of technology that will help solve evolving network challenges.

– Reduction of System Inertia

Inertia, which is the inherent capability of a power system to resist changes in frequency following a disturbance, is primarily provided by synchronous machines. Traditionally, system frequency is controlled with Automatic Generator Control (AGC) applied to individual generators that provide frequency response service to the system operator. The integration of non-synchronous renewable energy sources, such as wind and solar, reduces system inertia as these sources are connected via power electronic converters. One of the consequences of a reduction in system inertia, is the increased rate of change of frequency (RoCoF) during disturbances, increasing the risk of frequency instability and undesired operation of protection devices.

To manage this increase in volatility, the following solutions could be considered:

- **Demand Side Response (DSR):** The utilisation of DSR could assist in addressing frequency containment issues by providing an active power response from the demand side. During periods of generation shortfall, consumers who participate in DSR schemes could reduce their electricity usage, effectively compensating for the loss of generation.
- **Energy Storage Systems (ESS):** Technologies such as thermal storage, pumped hydro, and long-duration batteries, allow excess energy generated during periods of low demand to be stored and used at a later time. Such energy storage solutions could be rapidly activated during high-rate frequency events.
- **Synthetic Inertia:** Synthetic inertia involves the use of control systems in converter-connected devices, such as wind turbines, to provide an active power response that mimics the natural inertia of synchronous generators. During a frequency event, synthetic inertia could help dampen the rate and magnitude of frequency deviations by injecting power into the grid. However, this method introduces an energy deficit known as the 'recovery period' a few seconds later, which poses a challenge for continuous frequency support.
- **Synchronous Condensers:** Synchronous condensers are unloaded synchronous motors that can offer immediate inertia to the system. Several studies have shown that they can increase the tolerance for loss of in-feed events and improve voltage stability. Additionally, they can be retrofitted from decommissioned thermal plants, making them a cost-effective solution.
- **Maintenance of larger volumes of frequency response:** This involves contracting more generators to be in frequency responsive mode, ensuring a rapid response to frequency changes.
- **Constrain of the largest generation or interconnector in export mode:** This approach limits the output of the largest generators or interconnectors to reduce the impact of their sudden loss on system frequency.

– **Power Quality Issues**

Maintaining high power quality is crucial for the efficiency and reliability of the energy system. However, the integration of renewable energy sources (RES) in the grid introduces several power quality challenges. These issues arise primarily because RES generate power in a non-continuous manner, leading to fluctuations in voltage and frequency. Voltage fluctuations can damage sensitive electronic equipment and reduce their lifespan. Frequency variations on the other side, result from imbalances between supply and demand, leading to frequency deviations that can cause instability and potential blackouts.

Harmonics are another significant issue, introduced by power electronic devices like inverters used in RES. These devices cause harmonic distortions that can lead to overheating of equipment, interference with communication lines, and efficiency reduction of electrical devices. Additionally, reverse power flow can occur due to excess power generated by RES flowing back into the grid, causing voltage rise and protection issues.

To mitigate these power quality issues, several strategies can be implemented during network planning:

- Grid reinforcement, including the upgrading of transmission lines and substations, would enhance the system's ability to handle the variability of RES generation.
- Advanced inverters with control capabilities can manage voltage and frequency variations effectively, providing reactive power support and reducing harmonic distortions.
- Power quality devices such as Dynamic Voltage Restorers (DVRs), Static VAR Compensators (SVCs), and Unified Power Quality Conditioners (UPQCs) can be installed to manage voltage and reactive power issues. These devices respond quickly to power quality disturbances, maintaining stable voltage levels and reducing harmonics.
- Adoption of ESS both in grids and micro-grids.

– **Variability and Unpredictability of RES**

The variability of RES can create issues in maintaining a consistent and reliable power supply, which is crucial for the stability of the grid. The primary issue arises from the mismatch between the timing of renewable energy generation and electricity demand. Solar power peaks during the day and drops off in the evening

when demand typically reaches its peak. Similarly, wind power generation can be unpredictable, varying with wind speeds that are not always aligned with consumption patterns. This can lead to periods of surplus generation followed by shortages, complicating the task of balancing supply and demand. Additionally, the geographic distribution of renewable resources often does not align with population centres, necessitating extensive transmission infrastructure to transfer electricity to the distribution level.

To address these challenges, network operators need to develop advanced forecasting models that would leverage meteorological data to accurately predict renewable generation. These models can provide short-term and long-term forecasts, enabling grid operators to make informed decisions about energy dispatch and grid management.

In addition to forecasting, smart energy management solutions are essential for balancing electricity supply and demand. AI-driven energy management systems can dynamically adjust energy distribution based on real-time data, optimising the use of available renewable resources. For example, during periods of high solar or wind generation, excess energy can be stored in battery storage systems.

2.2.3 Procurement, skills and consumers

The increase of capex is only one element of the overall challenge; scaling up delivery programmes will place additional demand on supply chains and resources (both internal and external). With every country actively pursuing a pathway to decarbonisation, it is expected that there will be global challenges with securing the materials, labour and skills to deliver the investment required. The competition for these resources can lead to supply chain bottlenecks, delays in project timelines, and increased costs. Effective procurement strategies will be essential to mitigate risks associated with supply chain disruptions. This includes diversifying suppliers, establishing contingency plans, and fostering strong supplier relationships to ensure continuity and reliability.

There is also a recognised shortage in skills across the energy sector to help deliver the transition to net zero. The skills shortage spans various areas, including traditional engineering expertise but also those emerging skills in renewable energy technologies, energy efficiency, and smart grids. Recognising and addressing this skills gap is a crucial element to ensure a sustainable energy future.

Finally, the role of the consumer is an important element when considering decarbonisation challenges. The forecast uptake of electric vehicles and heat pumps will require consumers to change their mindset, behaviour and approach as they transition away from carbon intensive transport and heating. Network companies play a vital role in assisting consumers connect these new technologies whilst ensuring that the fundamental requirements of the network are met (safe, reliable and resilient). New systems will be required to help process the volume of applications whilst capturing the data required for assessing the impact on the network. In addition, as consumers adopt EVs and solar PVs accompanied by storage systems, their role will evolve from being mere consumers to becoming "prosumers"—individuals who both consume and produce energy. This shift will necessitate significant behavioural changes, such as adapting to new charging routines for EVs and optimising their use of electricity to align with renewable energy availability. Prosumers will also need to engage with smart grid technologies, which will enable real-time monitoring and management of energy consumption and production. This active participation in energy management can help balance supply and demand, contributing to grid stability and efficiency. However, it should be noted that a large proportion of the population will not be able to access these new technologies (for example, those consumers that do not have access to a personal vehicle or live in accommodation where low carbon heating cannot be installed) and therefore will not gain from the benefits. Typically, this proportion of the population are those that will be most affected from the rise in use of system costs associated with the increased expenditure required for these new technologies. Therefore, it is important that network companies begin to work with the relevant policy makers and government bodies to ensure that the apportionment of costs and benefits is fair and justified.

2.3 Examples from Other Countries

Policy challenges, particularly in the areas of permitting and planning for networks and new projects, often create significant barriers to delivery of targets. Government support and clear guidelines to streamline these processes are crucial to reducing delays and ensuring that progress towards the decarbonisation targets is accomplished. Such initiatives have been successfully established in other countries, such as:

– **Spain:** Andalusia's Project Accelerator Unit

The regional government of Andalusia in Spain has established a "Project Accelerator Unit" (UAP) to expedite the administrative processing of permits and authorisations for projects deemed strategic. Launched in 2020, the UAP aims to streamline the management of strategic projects, significantly reducing the time required for approvals [21]. Projects recognised as having strategic importance receive preferential treatment, allowing them to bypass some of the usual bureaucratic hurdles. This initiative has been highly successful, promoting 137 projects with a total investment exceeding 13.5 billion euros and generating more than 49,000 jobs [22].

– **Austria:** Parallel Permit Applications

In Austria, developers can apply for multiple permits simultaneously, rather than sequentially, to accelerate the approval process for renewable energy projects. By allowing site selection and grid connection applications to be processed in parallel, Austria reduces delays and uncertainties associated with the permitting process. This approach ensures that developers can proceed with their projects more efficiently, minimising the time and administrative burden typically involved in obtaining the necessary approvals [21].

– **Sweden:** Box Model for Permit Flexibility

Sweden has adopted the "box model" for permits, which provides developers with greater flexibility in adapting technology specifications between the permit application and the construction phases of renewable energy projects. This model allows developers to specify a range of technology parameters, such as wind turbine tip height, within their permit application. By doing so, they can adjust the layout and components of a project to optimise the project based on the latest available technology without needing to reapply for new permits or conduct additional environmental impact assessments [21].

– **Germany:** Leading the Way in Battery Storage

In 2023, the German BESS market grew by 152% from the previous year, reaching a total installed capacity of over 12 GWh [23]. This increase was primarily driven by the strong performance of the PV market, with 87% of the annually built capacity installed at the residential level. In 2024, Germany continued to build on this momentum. The installed battery capacity increased from 8.6 GW to 12.1 GW, and the storage capacity rose from 12.7 GWh to 17.7 GWh [24]. This achievement positioned Germany as the leader in Europe in terms of grid-connects battery storage, with the majority of the batteries being lithium-ion. These accomplishments were heavily facilitated by various government incentives and tax reliefs, such as the exclusion of value-added tax (VAT) and income tax from energy production income for residential energy storage systems, and direct subsidies covering 30% of the total system cost.

– **United Kingdom (UK):** Achieving National Record in Wind Energy Capacity

The UK has continued to make significant advancements in wind energy capacity, establishing itself amongst the leaders in this sector. As of 2024, the UK reached a historic milestone of over 30 GW of wind generation capacity, enough to meet the annual power needs of more than 26 million homes and cut carbon emissions by more than 35 million tonnes a year [25]. Wind power accounted for 32% of the country's electricity demand, surpassing natural gas for the first time [26]. These achievements have been facilitated by several key initiatives, including the Contracts for Difference (CfD) scheme, which has awarded project contracts to generate an additional capacity of almost 11 GW [27]. Additionally, the ScotWind leasing round in 2022 allocated more than 10 GW of fixed-bottom offshore wind capacity and more than 19.4 GW of floating offshore wind capacity [28].

– **United Kingdom (UK):** Electricity Networks Strategic Framework

The UK also published the Electricity Networks Strategic Framework which sets out actions the government and the regulator are taking to ensure the network can act as an enabler of a secure, resilient and Net Zero energy system [29]. This framework outlines several strategies to facilitate the transition to the electricity network of the future. For example, 'Strategic Network Planning' emphasises the importance of more strategic network planning to ensure infrastructure is built in the right place at the right time. 'Future System Operation' focuses on preparing for future system operation by reducing network constraints and enabling strategic

investment through the design of the price control. 'Accelerating Infrastructure Delivery' highlights the need to accelerate the delivery of strategic onshore infrastructure and increase competition and innovation in onshore electricity networks. 'Streamlining Planning and Consenting' aims to streamline the planning and consenting processes for network infrastructure to ensure timely delivery. The framework also discusses the potential for creating thousands of green jobs and attracting significant investment opportunities through the transformation of the electricity network.

3 Flexibility Services

3.1 Flexibility Markets

As electrification of transport and heat becomes more prevalent alongside the increased uptake of renewables, it necessitates the development of the electricity system into a more decentralised and interactive system. The introduction of RESs in greater numbers in order to decarbonise the energy system puts stress onto both the transmission and distribution systems, pushing the need for greater flexibility and energy efficiency across the system [30]. Flexibility markets help to develop the network by encouraging changes in energy supply and demand in the network, by creating signals from monitoring energy flows. They assist with the integration of renewables and decentralised resources into the network and existing power markets by providing an efficient method of matching the supply and demand.

Due to the increasing levels of deployment of DERs, energy system management is shifting to a local approach. Local flexibility markets (LFMs) allow implementation of flexibility by SOs at local level, using DERs to benefit the local system through methods such as minimising outages and avoiding grid expansions. For LFMs to be effective, cooperation between TSOs and DSOs is needed, meaning system operators (SOs) procure flexibility together in a joint effort. It allows grid issues to be solved more efficiently and allows different customers to participate in a wide range of markets and may encourage interoperability between markets [31].

CAP24 sets out the goals of 15-20% demand-side flexibility by 2025 and 20-30% by 2030 for Ireland. Recognising flexible demand as an important part of reducing Ireland's carbon emissions, CRU have begun introducing regulatory oversight and incentives for activities increasing flexibility. One of the main programmes driving the introduction of LFMs and greater levels of flexibility to provide security of supply in Ireland is the 'National Network, Local Connections' (NN LC) programme, launched by ESB Networks in 2020. The programme supported the implementation of flexibility methodologies to allow customers to participate more actively in the energy system by managing their own consumption. Its implementation resulted in the first Irish local flexibility market being established in 2021 [32].

Development of the National Energy Demand Strategy (NEDS) Decision Paper, published by CRU in 2024, also provides some insight into implementing flexibility markets in Ireland, with an update expected in 2026/2027 discussing the scaling of competitive and liquid flexibility markets [33]. As a result of the NEDS, ESB Networks published the 'Phased Flexibility Market Development' at the end of 2021, which aimed to introduce LFMs onto the distribution system. Since then, flexibility markets have been introduced onto the system, with further plans to develop the markets such that new energy communities may participate in LFM arrangements and greater support is given to participants through a new flexibility market platform, as seen in the 'Flexibility Multi-Year Plan 2024-2028', which is part of the NN LC programme [34].

3.2 Energy Storage Solutions (ESS)

There are many different types of energy storage solutions (ESS), all with the purpose of storing excess energy generated during periods of low demand and deploying it at a later time. Such solutions are able to be activated when needed on the grid to balance supply and demand and ensure security of supply. ESS provide crucial support to the electricity system in order to connect increased renewable generation and can result in significant cost savings to electricity consumers.

ESS can help mitigate the challenges of creating a carbon-neutral grid, such as reducing curtailment of RES, allowing greater levels of congestion management and supporting the grid in locational pinch points by dispatching

electricity at specific times and locations. ESS can also help maintain a balanced, stable grid by working alongside non-synchronous power sources, such as solar and wind, to maintain the grid frequency and voltage. As every different type of ESS has its own advantages and disadvantages, in order to ensure a stable system, multiple ESS should be used in tandem. Investment into ESS technology can also reduce the need for investment into the network and save expenditure into energy system costs.

Ireland currently uses two kinds of ESS, battery (BESS) and pumped hydro (PHS), the two storage technologies most widely used globally, with battery storage making up the majority of Ireland’s storage capacity. Ireland now has over 1 GW of electricity storage systems providing services and demand flexibility, with more being developed in order to meet the CAP and Sectoral Emissions targets of increasing RES to 80%, supporting 20-30% demand side flexibility and reducing the carbon emission budget by a further 20 MTCO₂eq, all by 2030. Roughly 730 MW of capacity is produced by BESS, with a further 292 MW produced by PHS [35].

3.2.1 Battery Energy Storage Solutions (BESS)

Battery energy storage systems (BESS) are collections of batteries that store and discharge energy on demand. They store energy when supply is high and the price of electricity is cheaper, and discharge that energy when demand is high, and the price of energy is more expensive. They are used in conjunction with renewable energy generators, especially solar and wind sources, whose intermittent nature make them less reliable than other energy sources. BESS help balance the supply and demand, allowing less reliable renewable energy sources to become viable as large-scale generation options. This conjunction of BESS and solar and wind renewable energy reduces carbon emissions, increases energy efficiency and supports grid stability, allowing investment into more renewables in order to meet the goals set for carbon neutrality [36].

BESS can also be used to support conventional generation, through different methods of providing grid flexibility and stability. They can perform remunerated energy services, such as electricity frequency regulation or electricity volume balancing. They have a fast response and more precise local voltage control than some other forms of ESS, which enables greater flexibility on the grid. The two most common types of BESS are front-the-meter (FTM), for asset owners, and behind-the-meter (BTM), for energy consumers, which fulfil different purposes to promote a more reliable, low carbon grid. BTM BESS are connected behind the utility service meter of commercial, industrial or residential consumers, with the primary goal of managing consumer energy and providing electricity bill savings. They can be used to encourage demand-side flexibility services in energy consumers. FTM BESS integrate into a distribution network or transmission system and can be applied in many different capacities, as presented in Figure 3.1 [37]:

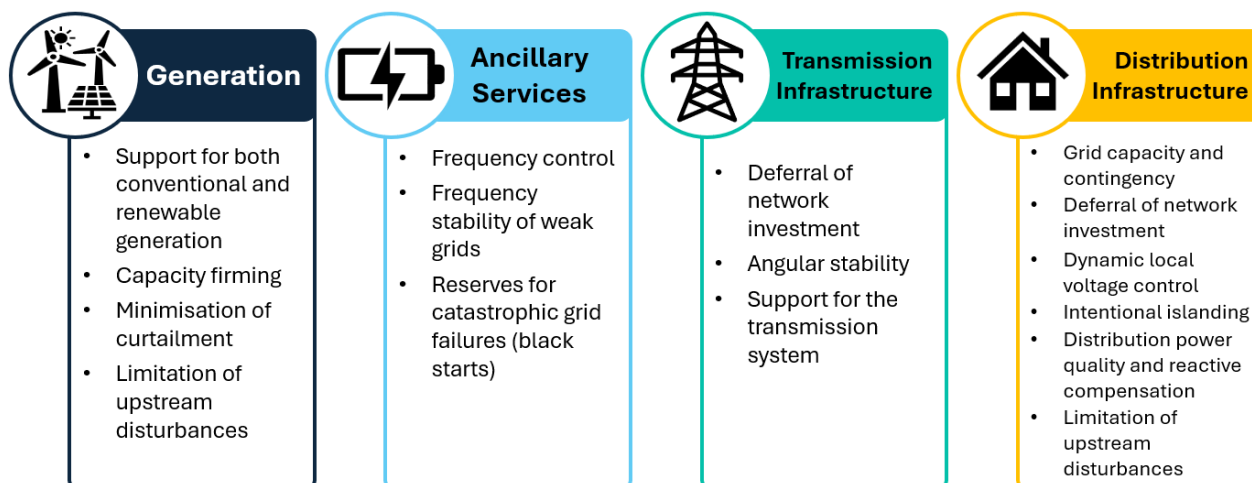


Figure 3.1 Uses of FTM BESS

Ireland have already begun to install utility-scale BESS projects, with the first battery system energising in 2018 and inducing rapid development of other projects. Of the approximately 1 GW of capacity stored using ESS, BESS makes up around 730 MW, providing on-demand dispatchable power. However, it is worth noting that the BESS in Ireland is all short-term, with 2 hours or less duration capacity [35].

3.2.2 Pumped Hydro Storage (PHS)

Pumped hydro storage (PHS) is a kind of mechanical storage, using kinetic energy to create and store electricity. Water is pumped from a low reservoir to a higher one using electricity from the grid when the price is low, then allowed to flow back down, where a turbine connected to a generator is spun, creating electricity when there is greater demand. Multi-hour PHS is currently responsible for the largest share of grid-scale electricity storage worldwide.

As with all forms of ESS, PHS is particularly helpful with intermittent forms of generation in RES, supporting a stable and reliable grid by maximising the use of the clean energy and allowing the increase of renewable generation connected to the grid without compromising the ability to meet demand. PHS generally have a higher capacity and longer duration than BESS, as well as a long lifetime. They are flexible with the amount of power they generate, meaning they are well-suited to balancing the supply and demand on a grid. However, it is generally slower to respond to changes in the grid than other forms of ESS and has obvious geographical constraints.

Ireland has one PHS site, Turlough Hill in County Wicklow, operational since 1974, which has four reversible pump turbines for a rated power of 292 MW and a storage capacity of 1.7 GWh, making up almost a third of Ireland's current ESS capacity. A second PHS site, Silvermines, has been identified and is expected to be commissioned in 2030, providing 1.8 GWh of storage with a 360 MW export capacity. This project is designated a Project of Common Interest (PCI) and is listed under the Trans-European Networks for Energy (TEN-E) regulations by the European Commission [35].

3.3 Demand Side Response

Demand side response (DSR) is a method to help balance electricity supply and demand, most often when demand exceeds the supply, by managing consumers' power consumption to better match the supply. By shifting demand, grid stability and energy efficiency are enhanced by reducing grid capacity stress, which prevents outages. As well as balancing supply and demand, it also allows peak demand to be managed, reducing the network investment required to meet rising demand due to electrification. Managing the demand allows greater leeway for the introduction of renewable generation, as the output can be intermittent and unreliable [38].

There are two methods for implementing DSR, explicit and implicit. Explicit DSR means that consumers have a financial incentive to adjust their demand at any point, typically upon request from a system operator. This can be performed by the consumer themselves, or a DSR aggregator acting on the consumer's behalf. This also promotes the uptake and development of DSR in larger energy consumers. Implicit DSR refers to voluntary changes made to the usual electricity consumption patterns of end consumers. It is generally done in response to short-term market signals and is feasible for domestic consumers as well as commercial and industrial users. The implementation of implicit DSR is likely to further develop with the roll-out of smart meters [39].

Methods for households and companies to effectively perform DSR are varied, with some options providing more flexibility than others, largely depending on how easily demand can be shifted by the device. However, there are some barriers to adequately providing DSR [40]:

- **Accurate reporting of energy information**

Both explicit and implicit DSR relies on knowing both how much energy is used and when it is used, to understand when demand needs to be shifted. It is also necessary in order to provide compensation, if the consumer is participating in explicit DSR. This problem can be mitigated through the use of smart meters, which measure real-time electricity use.

- **Connectivity of devices**

When implementing DSR, devices need the ability to quickly receive and respond to market signals. This also extends into interoperability and cybersecurity of devices.

- **Feasibility of DSR**

Energy consumers all have different levels that they can participate at, depending on multiple factors, such as the devices that are available, the ability to shift demand on request and the energy consumer's baseline demand before DSR is employed. If a consumer has a low baseline demand, even if they are able to shift demand, the measured difference may not be significant enough to meet the goals set when participating in

the market. Thus, there is a lower chance of receiving revenue for providing explicit DSR, and the incentive to participate is reduced.

– **Understanding of technical requirements**

In order to provide DSR, consumers need to understand the market signals provided and the appropriate response. While this issue can be somewhat mitigated through employing DSR aggregators, for smaller or domestic energy consumers who may manually perform DSR, this is more of a problem, with the chance of penalisation if they do not respond as expected.

The need to begin implementing DSR has been recognised by Ireland. NEDS discusses the need for flexibility and sets out ambitions to reduce the barriers for energy suppliers, consumers, aggregators and others for active demand-side market participation. It aims to incentivise the uptake of DSR in consumers by 2030 [33], and the European Commission is currently reviewing a proposal for a new EU-wide Network Code on Demand Response [41] following a public consultation [42], which will shape the framework in this space. Schemes for different kinds of energy consumers with the goal of providing DSR have also been implemented, such as the the NightSaver tariff-based scheme, which also allows domestic energy consumers to partake in demand side management [43]. Alongside these schemes, demand side units (DSUs), which are demand sites that can reduce their electricity consumption when requested by the National Control Centre (NCC), participating in the market are developing further.

4 Data and Digitalisation

Digitalisation is necessary for successful decarbonisation of the energy system at least cost, as areas emerge that are reliant on new technologies, such as smart meters, that require reliable data transmission to both receive and provide accurate data. This also requires secure data hosting, which should ensure the data is available and accurate. The move towards a digitalised energy is often impeded by data, be it of a poor quality, inaccurate or missing, whilst other valuable data is restricted or hard to find. Other concerns are in preserving data privacy and cybersecurity, while also developing solutions that are future proofed. Thus, steps need to be taken to implement measures that ease the pathway into developing a digitalised energy system.

The EU Commission published an action plan in October 2022, 'Digitalising the energy system', which aims to support development of a sustainable, secure and transparent market for digital energy services to incentivise the digitalisation of the system [44].

4.1 Open access data

Open access data refers to data that is publicly available for use, modification and distribution, with no restriction. It allows greater amounts of data to be more easily accessed, enabling increased interoperability and capabilities across the energy sector. Open data is also an important component of increasing the value consumers can gain, by enabling more control in their participation of energy markets and behind-the-meter services.

Establishing a trend of open data helps to combat one of the challenges of digitalisation – the irregularity of data. Historically, energy system data has been overprotected, leading to data that is not easily accessed, but also of a variable quality and coverage [45]. Data visibility through an open access method allows a view on existing data, what data is missing, and which datasets are important. This increased data access can also lead to the development of open markets and better management and operation of the system. Further benefits that can be achieved with open data include:

- **Innovation:** As the barriers to accessing data are reduced, new business models and value propositions will be created as innovators are attracted, resulting in the development of new markets.
- **Improved Operation:** An increase in accessible data means more informed decisions can be made at all levels across the system.
- **Transparency:** Improved insight can be generated from open data, including production of more rigorous energy statistics.

In conjunction with establishing an open access data pool, collection of that data should be properly considered. In many cases, this requires input from all areas of the energy network, from system operators to consumers, especially with the rise of prosumers. As such, registration of network assets is an important factor to consider. To collect data that is both complete and reliable in an efficient manner, simple methods for asset registration must be established. These methods should be user-friendly for consumers, businesses and intermediaries, which will also boost registration compliance. Pushing registration through a single, central portal has been proven in projects across other countries and sectors to be successful, such as in the German energy system which has a single registration portal for all assets and market participants, or the UK Food Standards Agency, which uses a single portal for registration of all food businesses [46].

While open access data provides many benefits and combats one of the key factors hindering digitalisation of the energy system, there are some concerning issues within data collection, including across the privacy and security of data. Mitigation measures, such as reducing data sensitivity, must be put in place to assuage these issues.

4.2 Cybersecurity

Cybersecurity is the implementation of technologies and policies that prevent or mitigate the impact of cyberattacks. It aims to protect digital systems and data from threats such as malware and data theft. With the push for a more digitalised energy system, the threat from cybercrime increases, solidifying the need for robust cybersecurity to mitigate this risk.

Cybersecurity in the energy sector has a few areas in particular that require more consideration due to the possibility of critical and widespread impacts. These include:

- **Real-time requirements:** Energy systems often need to react incredibly fast to changes in the system. This means that standard security measures that introduce even a slight delay cannot be utilised.
- **Interconnection:** Many electricity networks are interconnected on a global scale, such that an outage in one country's network may trigger blackouts or shortage of supply in another country.
- **Legacy systems:** Older systems on the energy system must interact with much more modern equipment and devices from the 'Internet of Things' (IoT) for automation and control, without being exposed to cyberthreats.

A network code on cybersecurity for the electricity sector was published in May 2024, and subsequently adopted by the EU Commission, that presents sector-specific rules for cybersecurity regarding cross-border electricity flows. It sets out the minimum requirements necessary when implementing cybersecurity in the electricity sector, considering the areas of critical risk posed as digitalisation of the energy system increases [47].

4.3 User-friendly Interface

In order to facilitate greater participation from energy consumers in energy markets, such as flexibility, to push the growth of prosumers, a user-friendly interface is necessary. Without the ability to clearly understand and interact with key smart grid technologies, such as smart meters, the potential for energy management on the grid through the consumers is greatly reduced.

For the desired effect, energy management interfaces should clearly present a range of information to allow for management of energy usage on the side of the consumer. Real-time and historic data that allows consumers to track and identify their energy usage and areas they can improve, alongside information on their costs, can encourage consumers to make more informed decisions, adopting more energy-efficient practices with the financial incentive to do so clearly shown. This information should be presented in a method that is easy to understand, even for consumers with less knowledge in the energy sector. A good user-friendly interface will enhance the user experience and may encourage a wider adoption of smart technologies. It will also support other areas of digitalisation, such as data collection, by empowering consumer interaction [46].

4.4 Seamless integration with HEMS

Home Energy Management Systems (HEMS) integrate smart devices and renewable systems into a central intelligent hub to allow consumers to monitor and manage their energy use. They collect data from connected devices and allocates energy from this information in real-time [48]. Consumers are granted greater control over their energy consumption through remote control and automation of connected devices and systems, adjusting to user schedules but also responding to energy rates and peak hours. HEMS assist with getting value out of renewable sources, facilitating smart energy usage and promoting consumer flexibility through load shifting and demand response. As a result, consumers can gain cost savings on their energy bills and maximise the value of any renewable and smart systems connected to HEMS in a more convenient manner than through constant manual intervention [49].

With the increase of digitalisation on the system, an increased number of devices, new and existing, will be introduced. Compatibility between these devices and HEMS is an important aspect of creating a digital system, as it can encourage an uptake in smart devices by consumers and unlocks behind-the-meter flexibility. Facilitating greater consumer participation through HEMS will enable faster and more widespread digitalisation, as change can be enacted and encouraged from all levels of the energy system.

5 Electricity Supply and Demand in Ireland

This section explores the dynamics of electricity generation and demand in Ireland, with a focus on the drivers influencing these trends. It highlights the country's ambitious targets for renewable energy capacity and the progress made towards achieving these goals.

5.1 Electricity Generation

In 2023, Ireland's electricity generation mix for final consumption, as shown in Figure 5.1 below, highlighted a significant reliance on both renewable energy sources and natural gas. However, the substantial increase in renewable energy generation from previous years underscores Ireland's commitment to transitioning towards green energy sources. In particular, wind power provided 11.7 TWh of electricity generation, contributing to a total 33.7% of total supply [50].

This shift is in line with the country's efforts to reduce its carbon footprint and phase out high-emission energy sources like coal and peat. The notable contribution of electricity imports also emphasises the importance of cross-border energy cooperation in balancing supply and demand, especially during periods of low renewable generation.

Finally, it is important to note that 34.9% of primary energy input was lost during the transformation process, indicating that energy efficiency upgrades of the system need to be considered [51].

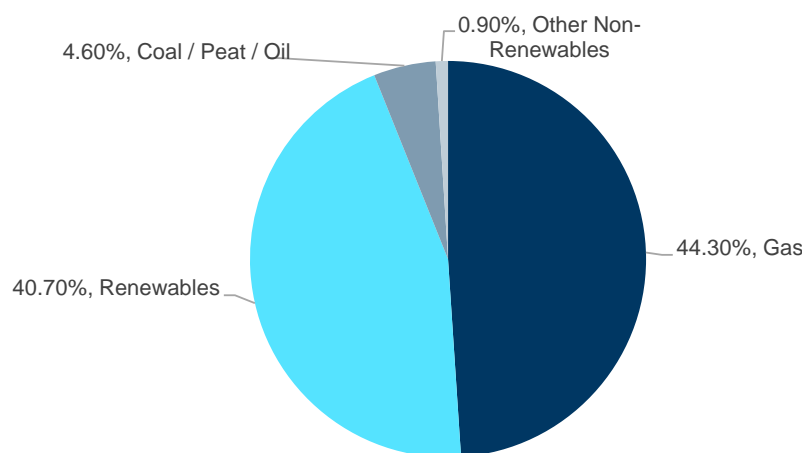


Figure 5.1 Electricity generation mix in Ireland as percentage of demand in 2023

5.2 Renewable Generation Targets

For Ireland to achieve its ambitious renewable energy targets of 50% by 2025 and 80% by 2030 set by the CAP, significant upgrades to the network will need to be considered. These include enhancing grid flexibility, implementing advanced grid management technologies, and expanding grid capacity to accommodate new renewable energy projects. Moreover, the variability of renewable energy generation necessitates the development of robust energy storage solutions to balance supply and demand effectively. The transition also demands coordinated policy and regulatory frameworks to support the rapid deployment of renewable energy technologies and to address potential bottlenecks in project approvals and grid connections.

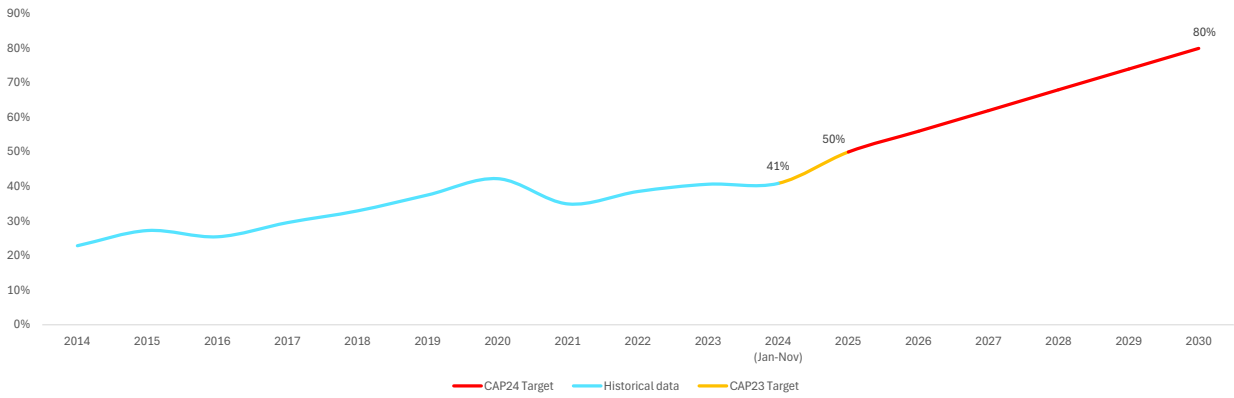


Figure 5.2 RES share in electricity generation in Ireland [50]

A notable increase in renewable generation from previous years can be seen in Figure 5.2, reflecting the country's commitment to sustainable energy. In 2023, renewable energy sources contributed approximately 40.7% to Ireland's electricity generation. The majority of this renewable electricity came from wind and solar energy. In December 2024, 46.7% of the country's total electricity demand was met from renewable sources with wind power alone providing 1,287 GWh and contributing to 41.4% of the demand [52].

By 2030, the goal is to achieve an 80% share of electricity generation from renewable sources under CAP24. This target is not only part of Ireland's broader strategy to reduce carbon emissions but also aligns with the EU's Renewable Energy Directive (RED-III). The interim and final capacity targets for 2025 and 2030 for the main sources of renewable generation in Ireland are presented in Figure 5.3 below.

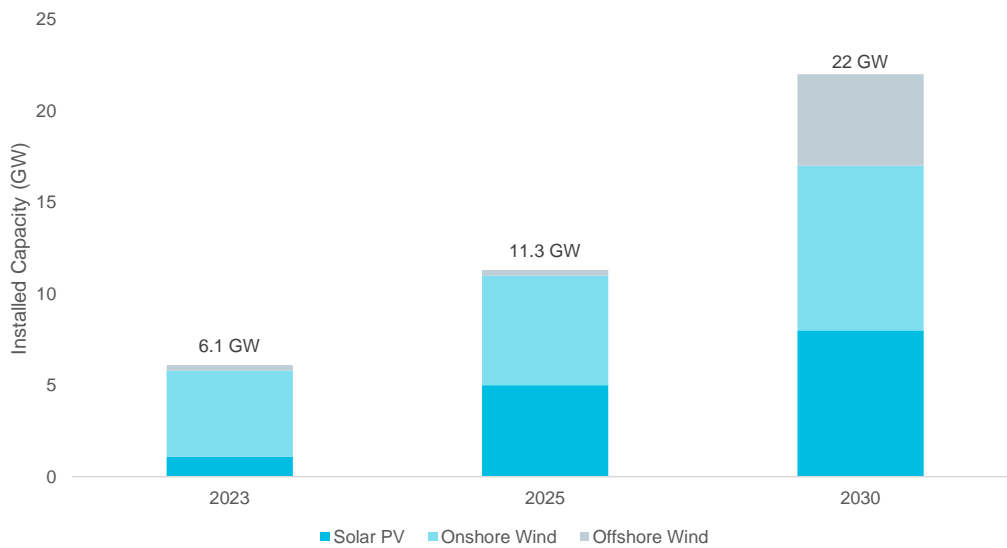


Figure 5.3 Renewable energy capacity targets by source in Ireland

5.2.1 Solar PV

As of 2024, Ireland's solar energy capacity has seen significant growth, reaching 1,185 MW [53]. This represents a significant increase of 42.6% from the previous year, highlighting the rapid expansion of solar power in the country. This increase is demonstrated in Figure 5.4. The majority of this capacity comes from large-scale solar farms, but there is also a substantial contribution from residential and commercial rooftop installations, which account for 417 MW.

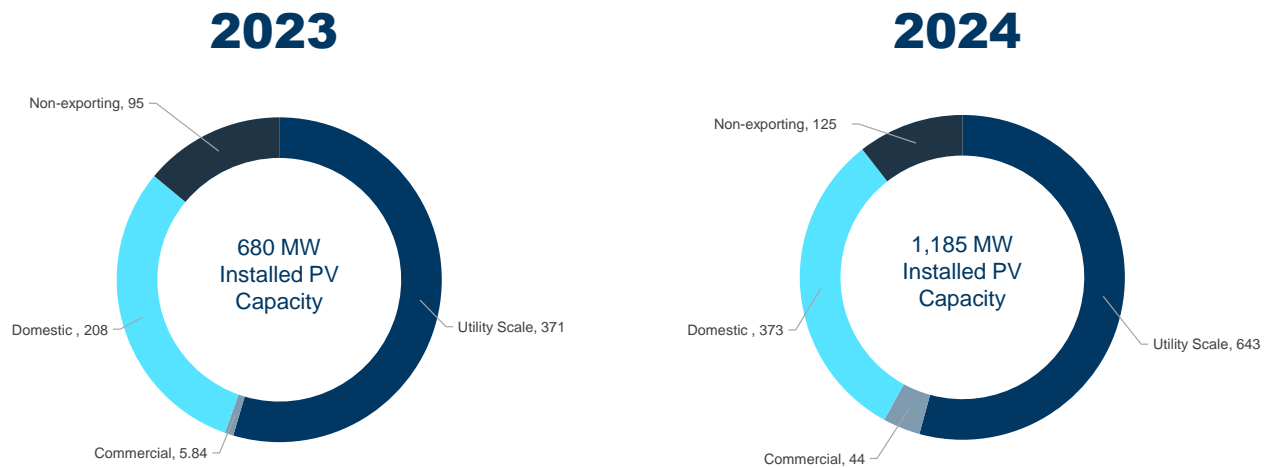


Figure 5.4 Year-to-year change in solar PV installations in Ireland

Looking ahead, Ireland has set an ambitious target to achieve 8 GW of installed solar capacity by 2030. As per SEAI, achieving this target will require adding an average of 1.04 GW of solar capacity each year [18]. Additionally, there is an interim target to reach 2.2 GW of installed capacity by 2025, which is nearly double the current capacity. To support this growth, the government has employed various initiatives and funding programs.

SEAI has conducted detailed analyses and projections regarding Ireland's solar energy capacity [54]. According to their latest data, there are two primary scenarios: the "With Existing Measures" (WEM) and the "With Additional Measures" (WAM) implemented. The WEM scenario examines the impact of measures that were already in place at the end of 2022 to meet the targets set in the CAP23, whereas the WAM scenario explores the outcomes of the implementation of the most recent regulations set by the Irish Government by the time of the 2024 National Energy Projections Report's publication and in this instance aims to meet the CAP24 targets. Unfortunately, both scenarios indicate that Ireland is unlikely to meet its 2030 target, as indicated in Figure 5.5 below.

In the scenario with existing measures, the SEAI projects that Ireland will fall short by at least 2.3 GW. This shortfall is attributed to several factors, including the current pace of solar installations, regulatory and planning challenges, and limitations in grid infrastructure. Even with additional measures, such as increased funding, policy support, and technological advancements, the projections still show a significant gap between the target and the expected capacity.

The SEAI's analysis highlights the need for more aggressive and comprehensive strategies to accelerate solar deployment. This includes streamlining the planning and permitting processes, enhancing grid capacity and flexibility, and providing greater financial incentives for both large-scale and residential solar projects.

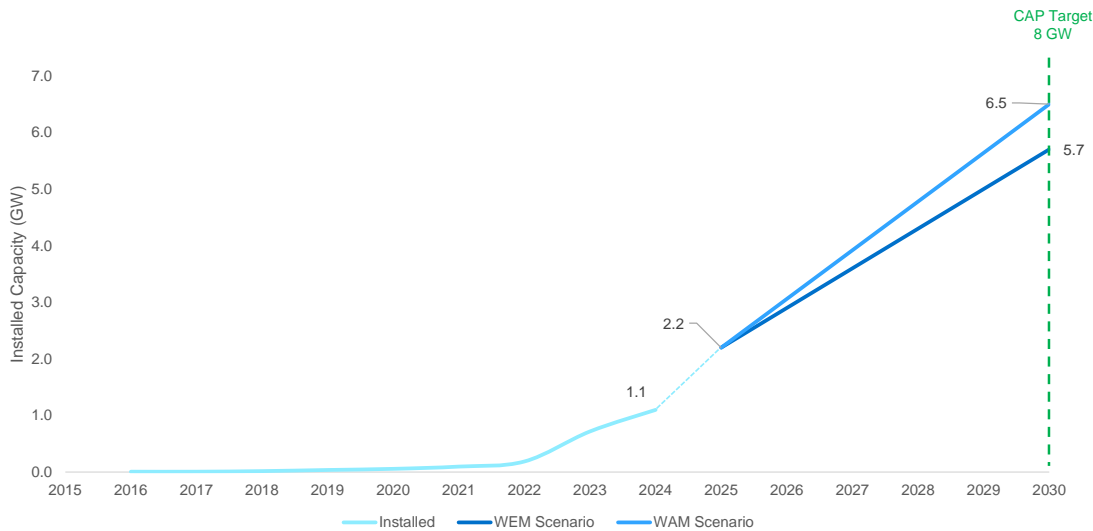


Figure 5.5 Solar PV installed capacity and projections in Ireland based on the WEM and WAM scenarios

5.2.2 Onshore Wind Energy

As of 2024, Ireland's onshore wind energy capacity has reached a significant milestone of 5,585 MW [55]. Wind farms across the country generated approximately 13,258 GWh of electricity last year contributing to 32%, down by 3% compared to 2023, of the total electricity demand [56].

In the SEAI's scenario with existing measures, Ireland is projected to fall short of its 9GW target in 2030 by around 2,000 MW [54], as seen in Figure 5.6. This is primarily due to *'delays in the deployment of variable renewable generation capacity'*, which results from a number of factors including provision of connections to the grid. Even with additional measures, such as increased investment in grid capacity and streamlined planning processes, the projections still indicate a gap between the target and the expected capacity. Continued efforts to enhance grid capacity and streamline planning processes are considered essential to achieve the country's 2030 goals.

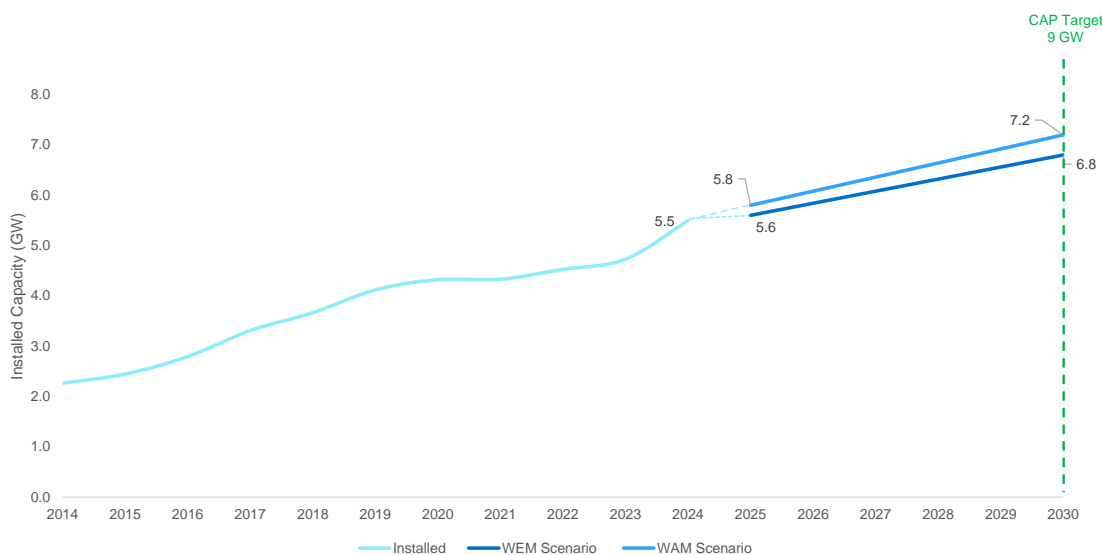


Figure 5.6 Onshore wind installed capacity and projections in Ireland

In addition, the planning body responsible for granting permissions, An Bord Pleanála, has been criticised for its slow decision-making process and the backlog of applications. In Q3 of 2024 only one project of 63 MW was granted planning permission, while 34 projects totalling 1,730 MW are still awaiting decisions [57].

Despite the challenges, there have also been positive developments. In 2024, approximately 333 MW of new onshore wind projects were connected to the grid, marking a significant step forward in Ireland's renewable energy journey. Additionally, the Renewable Electricity Support Scheme (RESS 4) auction was a notable success, securing 1,334 MW of new onshore capacity [58]. The results of the RESS auctions are shown in Figure 5.7.

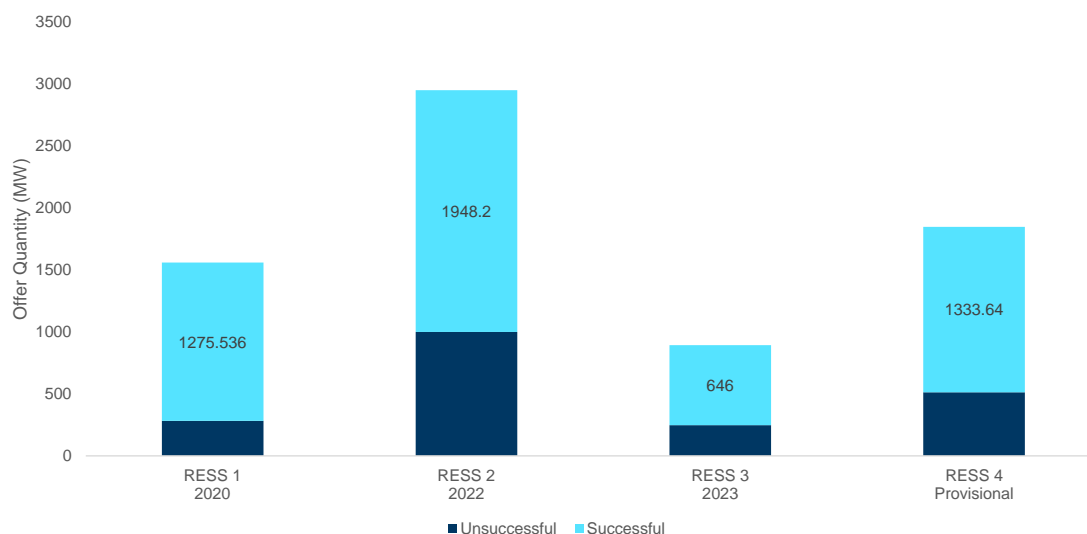


Figure 5.7 RESS auction results in Ireland

5.2.3 Offshore Wind Energy

Ireland's offshore wind capacity is still in its early stages, with a current installed capacity of around 25 MW, as of 2024. Despite the country's vast potential for offshore wind energy, progress has been slower than anticipated. Ireland has set ambitious targets to achieve 5 GW of grid-connected offshore wind capacity by 2030 and 37 GW by 2050. However, SEAI has projected that these targets will not be met under current conditions as seen in Table 5.1 [54].

Table 5.1 Current and projected offshore wind capacity

Offshore Wind	2024	2025	2030
Current MEC (GW)	0.025	-	-
CAP24 Target (GW)	-	-	5.0
With Existing Measures (WEM) scenario Installed Capacity (GW)	-	0.03	2.7
With Additional Measures (WAM) scenario Installed Capacity (GW)	-	0.03	4.0

In order to secure further offshore developments, the Irish Government has established the Offshore Renewable Electricity Support Scheme (ORESS). The results of the first round of auctions (ORESS1) were published in June 2023 [59], with the process securing 3,074 MW of capacity plus a 'time-limited opportunity to secure an alternative route to market' for a further 1,175 MW of capacity across two unsuccessful projects [60]. The secured capacity is due to be provided by four successful projects, three of which are located in the Irish sea in the vicinity of Dublin and one off the coast of County Galway in the west.

It should be noted that a phased approach has been adopted to development of Offshore Renewable Energy (ORE). In phase one, 'the six most advanced offshore wind projects in Ireland awarded rights to occupy seabed via Maritime Area Consents, or MACs, in 2022' in order to participate in the first auction.

One of the primary challenges hindering the development of offshore wind energy in Ireland is the complex and lengthy planning and permitting process. The Marine Planning and Development Management (MPDM) Bill, which

aims to streamline the planning process for offshore renewable energy projects, has faced delays in implementation. To address these challenges, the Irish government is working on several initiatives to accelerate the development of offshore projects. This includes the establishment of the Offshore Wind Delivery Taskforce, which aims to coordinate efforts across various government departments and agencies to expedite the planning and permitting process [61].

Moving forward, Ireland is planning to hold its second offshore wind auction under the ORESS 2 this year. The auction is aiming to secure 900 MW of capacity from the Tonn Nua site off Ireland’s south coast, which is part of the South Coast Designated Maritime Area Plan (SC-DMAP). This identifies four maritime areas for offshore wind development [62]. The ORESS scheme is due to conclude in 2025 following two auctions (ORESS 2.1 and 2.2) covering the South Coast Designated Maritime Area Plan (DMAP) area [63]. A successor scheme is being considered.

5.3 Electricity Demand

The total electricity demand in Ireland has exhibited a consistent upward trend, driven by population growth, the uptake of LCTs and the expansion of energy-intensive users, such as data centres. This trajectory is anticipated to persist as Ireland advances its decarbonisation agenda, which will further amplify electricity consumption due to the electrification of transport, heating, and industrial processes. As forecasted by EirGrid in the median scenario of the recent Ten-Year Generation Capacity Statement 2023-2032 (GCS23), in 2030 the total system demand is expected to experience a 50% increase relative to its 2023 level, reaching 46.1 TWh [64] as demonstrated in Figure 5.8 below. It should be noted that the 2024 figure does not correspond to the total demand of that year, as the data’s end month is November 2024, and the final value is expected to be above 33 TWh.

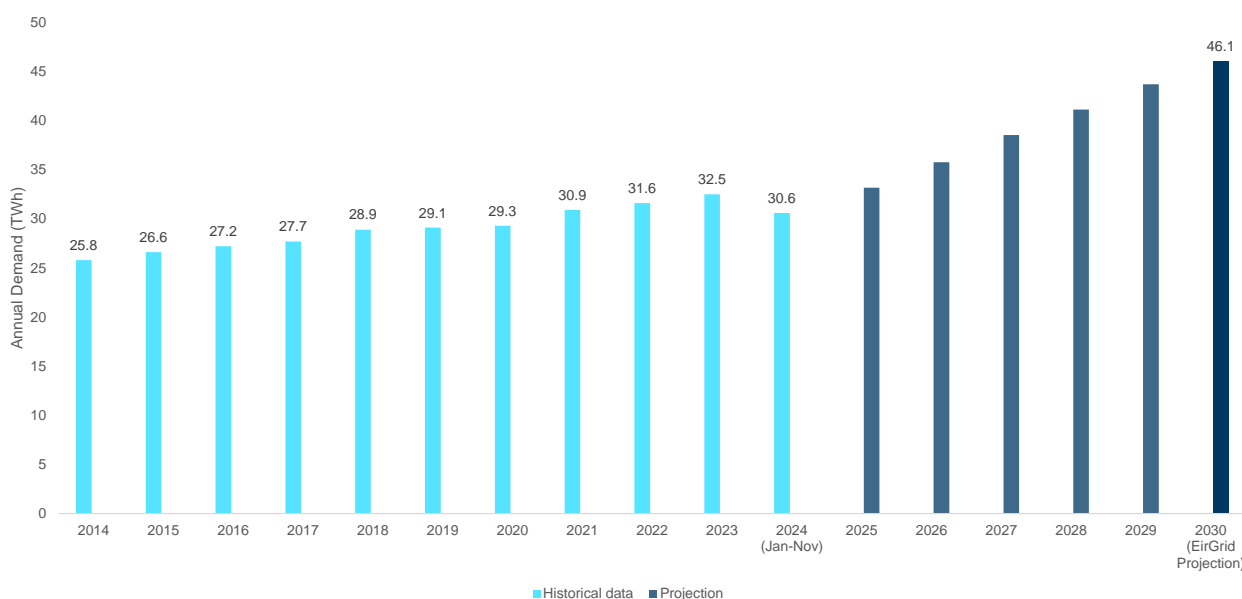


Figure 5.8 Annual total demand (TWh) in Ireland [50]

A key challenge associated with this increase is ensuring the grid has capacity to accommodate the augmented load without compromising system reliability. This necessitates substantial investments in grid infrastructure, including its expansion, to accommodate the connection of new generation sources but also the enhancement of the transmission and distribution networks to mitigate congestion and ensure efficient power delivery.

It should be noted that demand projections are, by their nature, forecasts that are subject to uncertainty. In its publications, EirGrid presents a range of forecast scenarios to recognise the inherent uncertainty within them. In the case of EirGrid, the changes in the last ten years have been relatively benign, with a modest increase in annual consumption.

In general terms, there is a tendency for demand forecasts by system operators to over-estimate the increases expected to be observed in the short-term. This is likely to be a result of following a conservative approach to ‘plan

for the worst', but also risks customers footing the bill for investment in infrastructure before it is strictly required. However, the ambition to transition to Net Zero means there is a strong consensus (in Ireland and other jurisdictions) that increased demand will be observed in the short-term.

5.3.1 Peak Demand

Peak demand refers to the period at which demand for electricity is at its highest. In 2022, peak demand in Ireland had risen to 5,530 MW, followed by a slight decrease in 2023, potentially as a result of the acute increase in electricity prices [50]. According to EirGrid, peak demand in the GCS23 median scenario by 2030 is set to reach 7,270 MW when an 8% decrease in demand is achieved due to the implementation of flexibility services and incentivisation of consumers, or 6,850 MW where an 8% decrease in demand is achieved with flexible EV charging [64]. Figure 5.9 presents the historical weather corrected demand along with the average of the two EirGrid 2030 forecast values.

As peak demand continues to rise, the electricity grid must be capable of handling higher loads while maintaining stability and reliability. Enhancing grid flexibility is essential to adapt to fluctuating supply and demand in real-time, which can be achieved through the deployment of smart grid technologies and energy storage solutions. However, it is recognised that significant upgrades to network assets will be required to meet the higher peak demands predicted.

By accelerating the deployment of both long and short duration BESS, supply and demand could be effectively balanced. As the penetration of renewable energy increases, the grid must be capable of storing surplus energy generated during periods of high production and discharging it during periods of peak demand. This capability is essential for maintaining grid stability and reducing dependence on fossil fuel-based backup power plants. Moreover, the implementation of advanced demand response programs will help manage peak loads by incentivising consumers to adjust their electricity usage during high-demand periods and allow the grid to rebalance and meet the system needs.

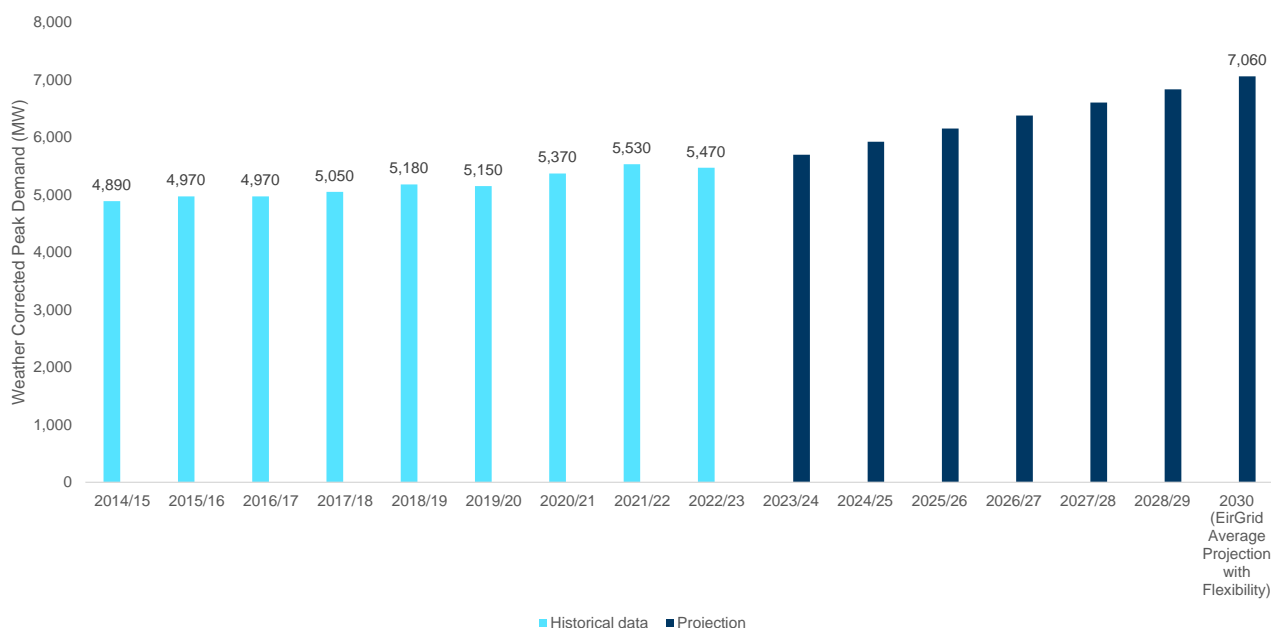


Figure 5.9 Weather corrected annual system peak demand (MW) in Ireland [50]

There is a notable shift in customer preferences towards connecting at MV and HV levels. This trend is driven by the need for more efficient and reliable power supply, especially for large industrial and commercial users, including data centres. As such, the grid is projected to experience an increase in demand at higher voltages, as seen in Figure 5.10.

The 'Smarter HV and MV Customer Connections' project by ESB Networks aims to innovate and improve the connection process for these customers, facilitating increased DER on the network and supporting Ireland's 2030 targets. This includes the introduction of Non-Firm Access (NFA) connection arrangements and Non-Wires

Alternatives (NWA) to maximize the use of existing network assets and reduce the need for extensive network reinforcement.

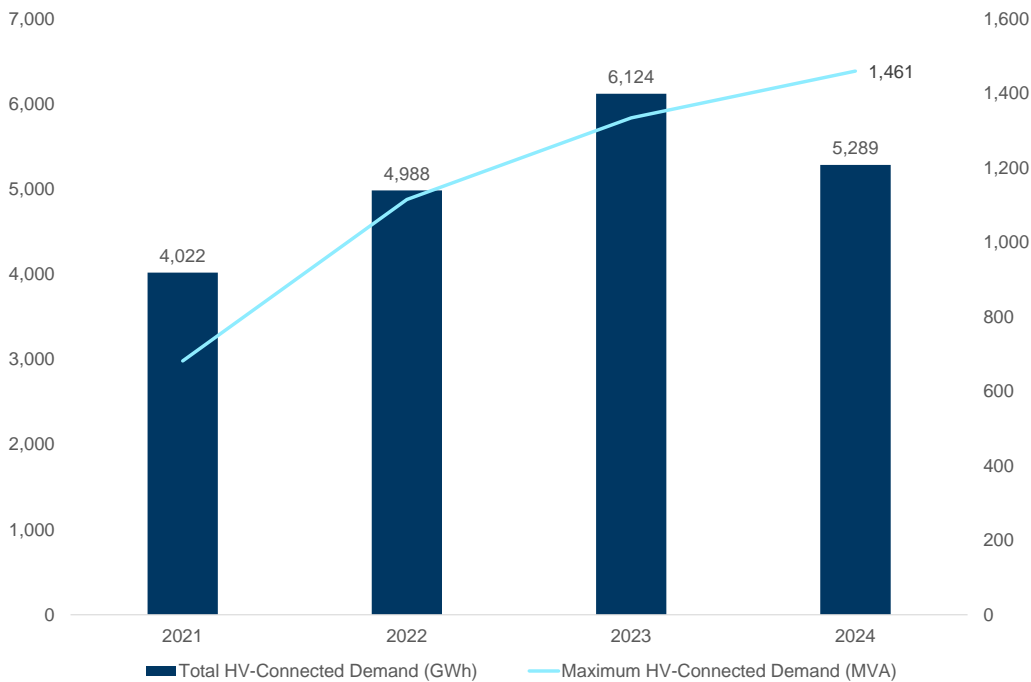


Figure 5.10 Transmission-connected customers' total demand [TSO data]

5.3.2 Electrification of Heat

Heat demand in Ireland for 2023 showed a heavy reliance on fossil fuels, which accounted for 90.2% of the total demand [65]. This high percentage indicates that the majority of heating systems are still dependent on oil, gas, and coal, which contribute significantly to carbon emissions. Renewable sources, on the other hand, accounted for 8.0% of the country's heat demand which is a relatively small share compared to fossil fuels.

As part of the decarbonisation of heat, Ireland set a 680,000 heat pump installations target by 2030 in CAP24, with 2/3 of these intended to be replacing traditional heating systems in existing buildings. The aimed increase in heat pumps is set to significantly impact the country's total electricity demand.

In 2023, heat pumps capturing renewable ambient heat accounted for 4.8% of renewable energy, surpassing hydro-electric generation and other technologies [65]. By the end of the same year, approximately 112,000 dwellings were recorded to have adopted heat pumps, up from 80,000 from the previous year. Latest data suggest that by the end of Q3 2024, 22,000 heat pumps were installed in new dwellings and through retrofits [66].

Despite these advancements, Ireland is relatively low in the ranking of all EU countries in terms of heat pump adoption. This, in addition to the 2030 national target, indicates that there is still significant potential for growth in this area, and further efforts are needed to increase the uptake of heat pumps and the sector's electrification rate. Key figures in the electrification of heat are presented in Figure 5.11.

48.4 TWh
Heat demand in 2023

680,000
Heat pump installations target by 2030

117,000
Heat pumps installed as of 2023

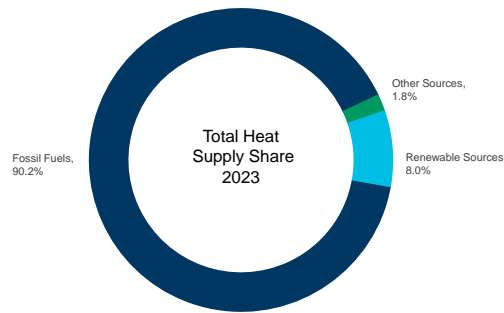


Figure 5.11 Electrification of heating in Ireland key figures

5.3.3 Electrification of Transport

The electrification of transportation in Ireland is a crucial step towards reducing carbon emissions and achieving sustainability goals. Currently, the transport sector represents 19% of Ireland's carbon emissions, with road transport and private car usage being the most significant contributors.

Based on CAP24, the country aims to have 945,000 EVs on the road by 2030, including private cars, commercial vans, and public transport vehicles. However, this ambitious target might not be achieved based on the current rate of EV adoption across the sector. Recent data suggest that new EV registrations dropped from 22,852 in 2023 to 17,459 in 2024, marking a 23.6% decrease [67].

To support the acceleration of EV adoption, the Irish government has set the Zero Emission Vehicles Ireland (ZEV) initiative which includes a €100 million investment fund for the upgrade and delivery of the EV charging infrastructure as part of the EV Charging Infrastructure Strategy [68]. Moreover, the initiative provides grants for domestic charging installations and tax-reliefs for battery electric vehicles (BEVs).

Currently there are around 2,500 charging points across the country [69]. The anticipated growth of EVs and charging stations will have a significant impact on the electricity network mainly due to the amplified increase in electricity total and peak demand. For the grid to be able to accommodate the system's needs and prevent any arising issues, the reinforcement and expansion of it at critical locations are considered highly important. Key figures in the electrification of transport are presented in Figure 5.12.

-2.5%
Overall plug-in market share in 2024

+268.7%
New plug-in heavy commercial vehicles in 2024

945,000
EV CAP target on the road by 2030

~2,500
Public charging points

0.3 TWh
Final electricity consumption in 2023

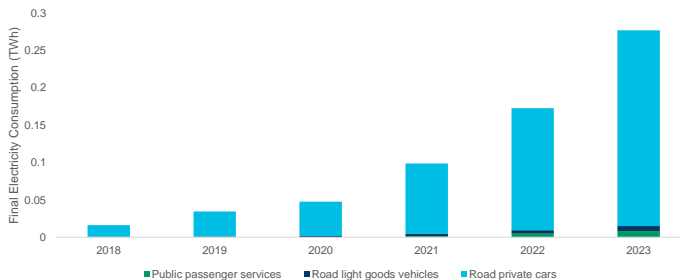


Figure 5.12 Electrification of transport in Ireland key figures [70]

5.3.4 Data Centres

Data centres in Ireland accounted for about 21% of the country's total electricity demand in 2023. This percentage represents a 400% increase in annual consumption compared to the 2015 levels, as shown in Figure 5.13 [71]. This substantial expansion is set to further increase in the following years due to the continuous growth of data and the digitisation of business operations across all sectors of the economy.

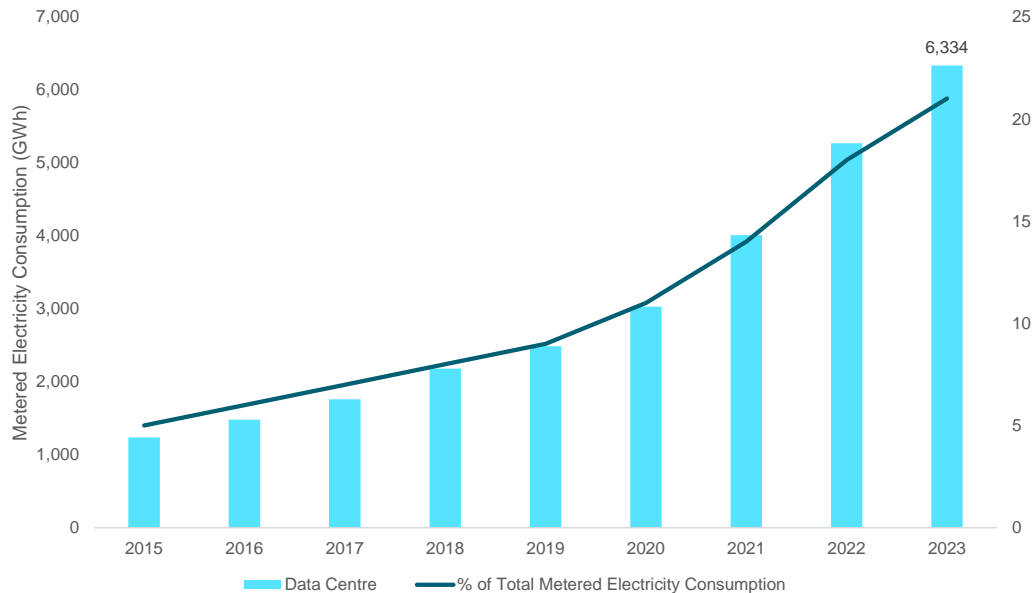


Figure 5.13 Data centres' power consumption in Ireland

The main driver of intense electricity usage in data centres is the need for cooling processes. As such, the largest part of the electrical power consumed is converted into waste heat to keep electronic components below critical temperatures.

The forecasted increase in energy demand from data centres will require significant upgrades to infrastructure across the electricity sector in Ireland, including the expansion of generation capacity and enhancements to the transmission and distribution networks.

The CRU has introduced policies to regulate the connection of data centres to the grid. These policies include criteria for determining whether a connection offer should be made, based on the location of the data centre and its ability to provide flexibility in demand. Additionally, data centres are encouraged to use dispatchable on-site generation and storage solutions to reduce their impact on the grid during peak times [72]. The Irish Government has also implemented measures to manage this growth, such as placing a moratorium on new data centre connections in the greater Dublin area until 2028 due to capacity constraints.

6 Assessment of the Network Company Business Plan Submissions for PR6

For the Business Plan submissions for PR6:

- EirGrid has put forward ambitious proposals for investment in transmission network infrastructure to be planned by EirGrid and delivered by the TAO (ESB Networks) following receipt of planning approval; and
- ESB Networks has put forward ambitious proposals for investment in the distribution network infrastructure in its role as the DSO.

When considering the requirements for an energy system, the investment proposals should be considered with regard to the network characteristics and associated parameters for network infrastructure, as illustrated in Table 6.1.

Table 6.1 Mapping of network characteristics to associated infrastructure parameters

Network characteristics	Associated network infrastructure parameters
Group 1: System peak demand Installed generation capacity Network constraints and curtailment	Installed capacity of substations (transformer capacity) Load-related expenditure
Group 2: Network constraints and curtailment	Circuit length and capacity (overhead lines and underground cables)

The following sub-sections present analysis of the:

- System peak demand;
- Installed generation capacity;
- Network capacity, including details of substation capacity, capacity headroom and constraints and curtailments in the transmission and distribution system in Ireland; and
- Load related investment proposals.

6.1 System Peak Demand

As illustrated in section 5.3, the peak demand on the Irish system is set to increase substantially over the coming years. Figure 6.1 provides a comparison of the following:

- Historical gross peak demand up to 2016, taken from the DSO PR6 BPQ;
- Actual transmission system maximum demand 2021-2024, taken from the TSO PR6 BPQ; and
- Historical (2016-2022) and forecast (2023-2032) transmission system peak demand taken from EirGrid’s Generation Capacity Statement (GCS) [64].

As can be seen from the chart, some data is missing from each of the PR6 BPQ submissions and it is not possible to definitively establish the impact of transmission-connected demand. However, there is consensus around recent published data for the transmission system peak demand in 2022-2024, which is in the region of 5.5 GW. In addition, whilst it has not been possible to fully reconcile the difference between the historical demand (taken from the DSO BPQ) and the historical transmission system demand (taken from the TSO BPQ), it is plausible that this can be attributed to the transmission-connected demand.

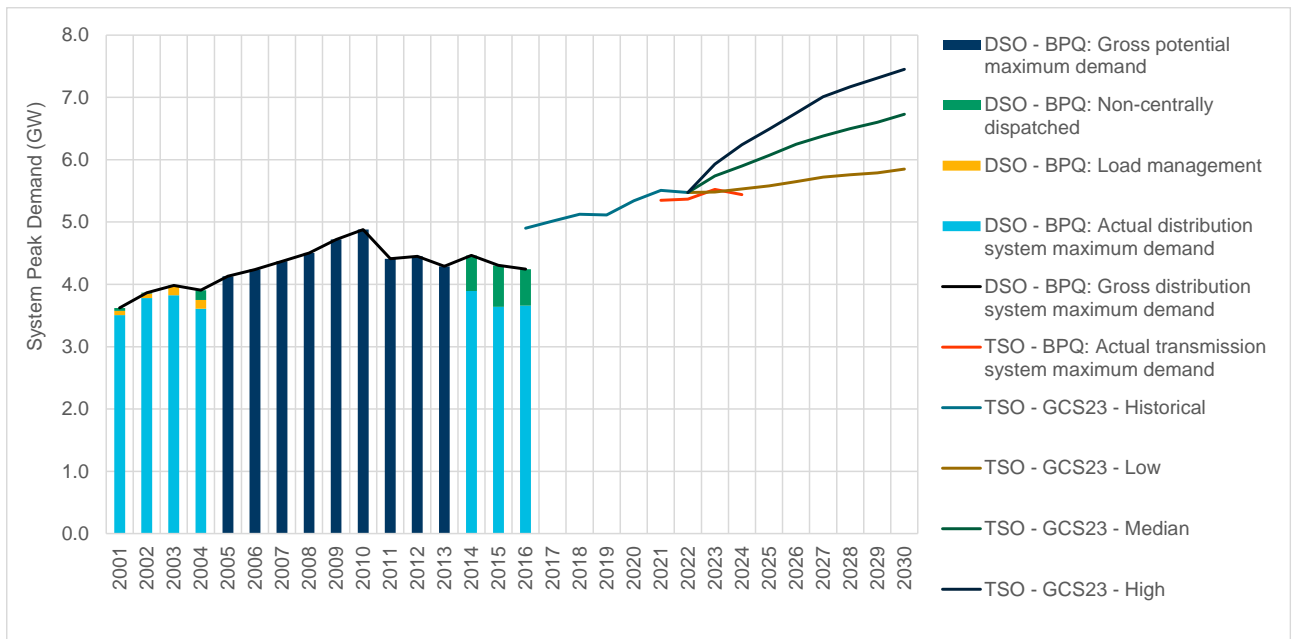


Figure 6.1 Comparison of System Peak Demand data from PR6 BPQs and other sources

Figure 6.2 presents a comparison of the short- and long-term forecasts of peak demand from GCS23 [64] and Tomorrow's Energy Scenarios 2023 (TES23)⁶ [73]. This chart shows a disparity between the short-term forecast up to 2032 and the long-term forecast from 2035 onwards. It is assumed that the NCs' business plan submissions are based on the short-term forecast values for the PR6 period. However, this chart indicates that the 2030 demand could be understated should the long-term trend be followed (difference of approximately 1.5 GW between the median short-term forecast scenario in 2030 and the value in 2030 corresponding to the linear trend from the 2022 actual to the mid-point of the long-term forecast scenarios in 2035).

For the purpose of the PR6 period, the increases from system peak demand of approximately 5.5 GW in 2024 to between approximately 6-7.5 GW in 2030 (9-36%) is assessed to be a reasonable estimate and is broadly consistent with the network company plans. Regarding the different forecast values, it is recommended that explanation should be sought from Eirgrid (outside of the PR6 process) for its published forecasts since such a step change in peak demand forecasts would have a significant impact on the level of investment required for PR7 and onwards. However, in our view we would expect the TES forecast to be aligned more with the GCS.

⁶ TES23 forecast scenario data has been interpolated between 2035, 2040, 2045 and 2050 data points.

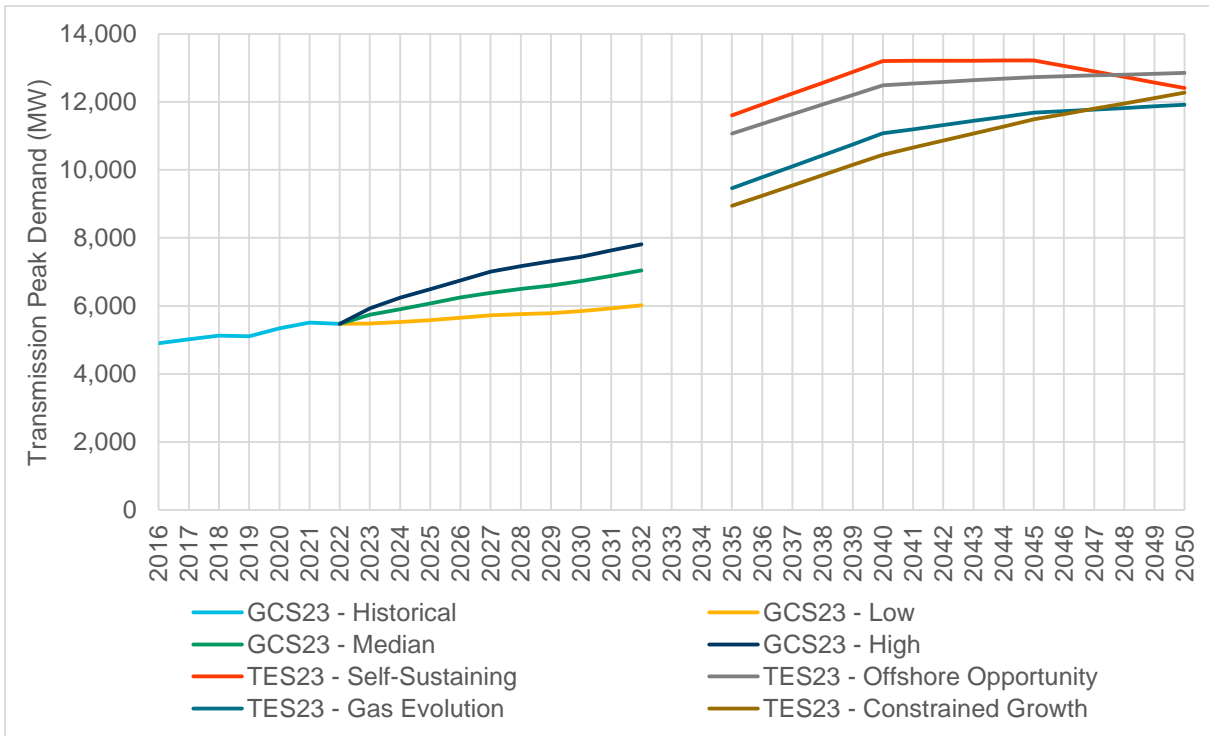


Figure 6.2 Comparison of short- and long-term forecasts of peak demand from GCS23 and TES23, respectively

Finally, Figure 6.3 presents the breakdown of the historical and median short-term forecast scenario peak demand. This shows that the ‘underlying demand’, corresponding to the residential, commercial and industrial demand exclusive of the impact of EVs, HPs, data centres and new technologies, is gradually reducing. This reduction is offset by the increases in demand attributable to data centres and the other category.

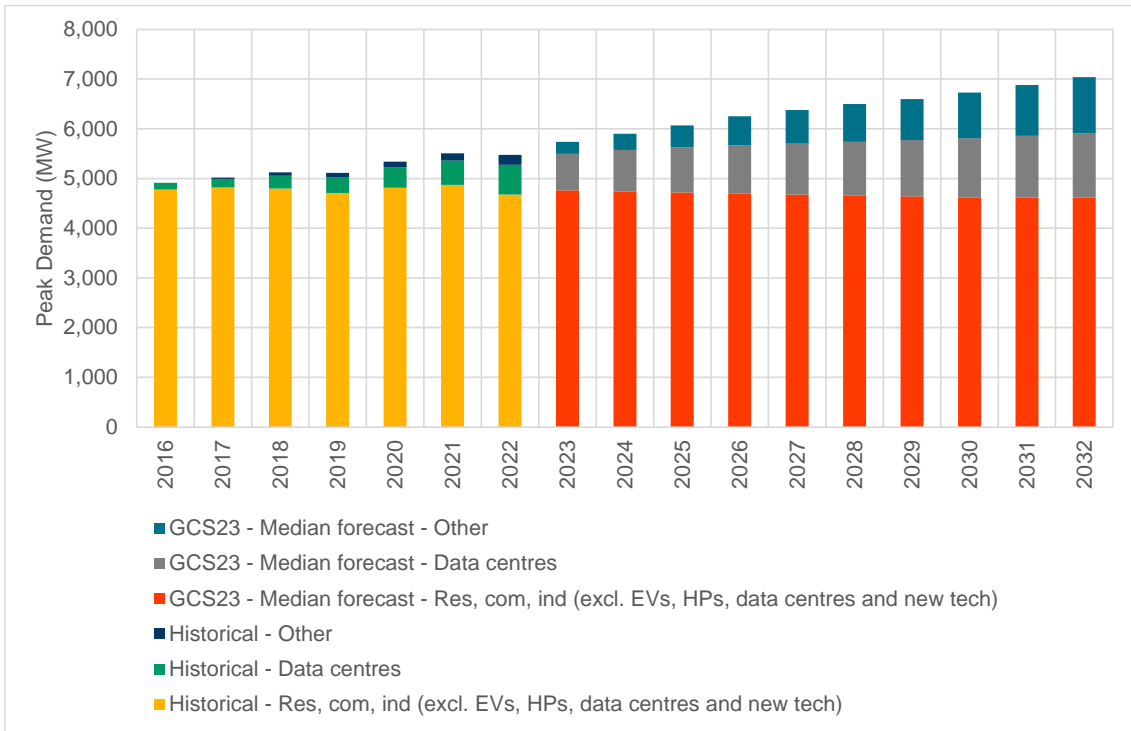


Figure 6.3 Make-up of short term peak demand forecast

It should be noted that Figure 6.3 represents a relatively modest increase in peak demand when compared with the trends described in section 5.3. It is clear that trends for electrification of heat and transport, further connection of data centres and connection of additional housing will all contribute to substantial increases in overall electricity consumption. The impact on the system peak demand appears to be tempered by reliance on flexibility measures

such that they do not necessarily result in corresponding increases at the time of the system peak demand. However, it is recommended that for future price controls EirGrid should be required to provide further explanation for its short and long-term forecasts, to ensure that they are built on the same basis so that they can be compared.

Overall, notwithstanding issues of consistency, the approach to scenario forecasting presented in Figure 6.1 and Figure 6.2 appears to be broadly in line with expectations from examples in other jurisdictions (e.g. FES by GB NESO). However, consistency and/or explanation of differences between published forecasts (e.g. GCS and TES), should be clearly demonstrated by EirGrid (and these should be clearly referenced in alongside proposed network interventions) to provide full confidence in future plans.

Figure 6.4 presents details of the PR5-6 actual and forecast annual NNLC connection volumes, based on data provided in the BPQ. This shows notable increases in the annual volumes of connections for the G1 - scheme housing and G2 - non-scheme housing connections. This is consistent with the requirements to support the 'Housing for All' plan, discussed in section 2.1.3.

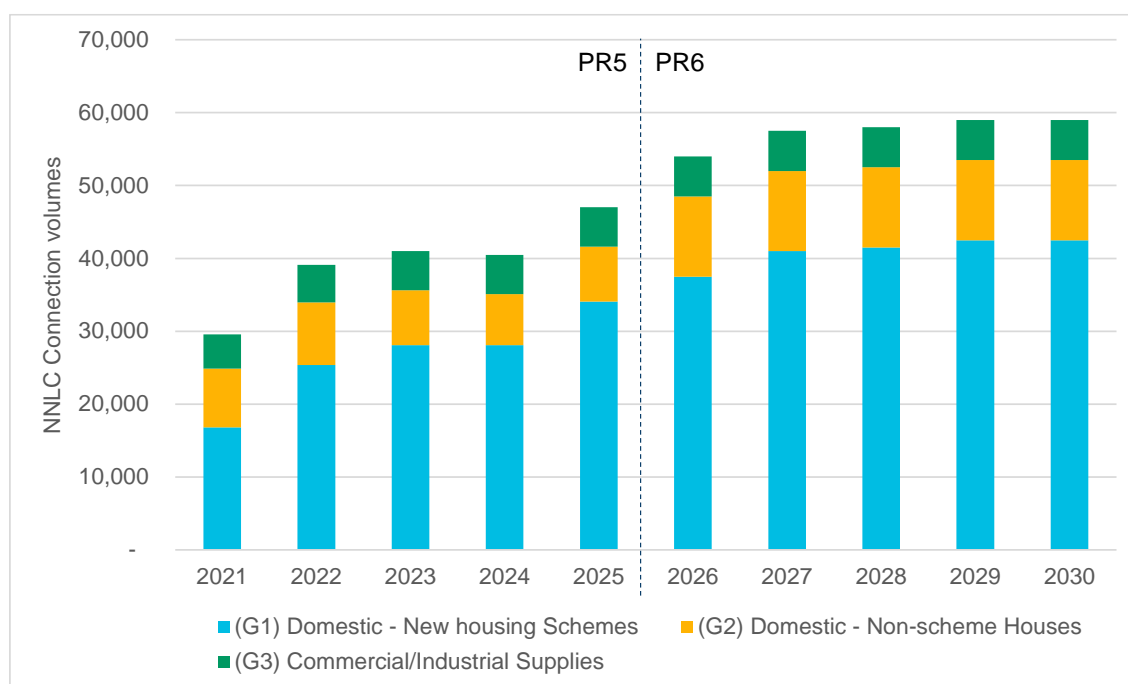


Figure 6.4 PR5-6 actual and forecast annual NNLC connection volumes

For additional context, Figure 6.5 and Figure 6.6 present the metered electricity consumption for distribution HV-connected customers and MV/LV connected customers, respectively. This shows a reduction in the consumption by 110kV connected customers over the last few years, which is understood to be due to shifts to the transmission network. From discussions with ESB Networks, it is understood that these shifts resulted from requests from large customers (e.g. data centres) previously connected to the DSO network to connect at transmission voltages to provide enhanced security of supply.

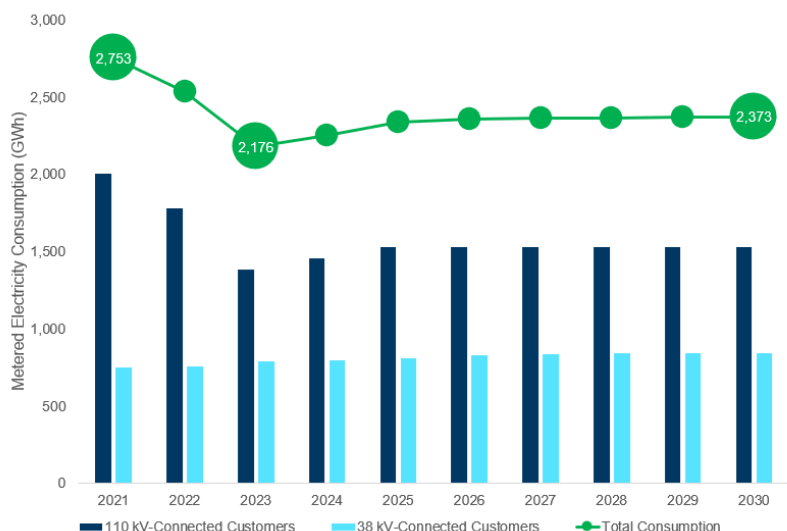


Figure 6.5 Distribution HV-connected customers' consumption

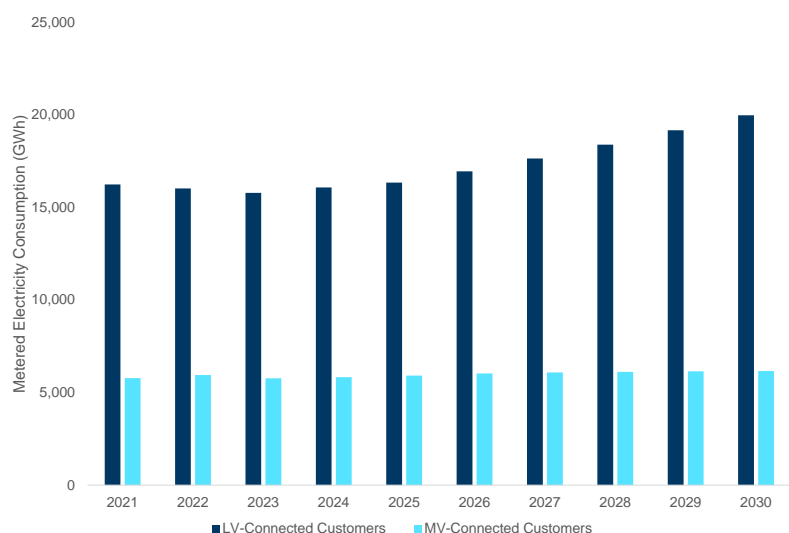


Figure 6.6 Distribution LV and MV-connected customers' consumption

6.2 Generation Capacity

Figure 6.7.7 and Figure 6.8.8 present different views of the connected and contracted generation capacity on the transmission and distribution systems, broken down by generation type and connection voltage, respectively. The contracted generation capacity has been spread equally across the years of PR6, to illustrate the potential trend over the period. Table 6.2 and Table 6.3, below the figures, present the values from the charts in tabular form.

The figures show substantial amounts of contracted solar (3.8 GW), wind (2.2 GW) and dispatchable non-renewable (2.0 GW) generation capacity. The dispatchable non-renewable capacity is made up of OCGT, CHP, gas/diesel and CCGT units.

These capacity increases are principally connecting to the network at 110kV (6.3 GW).

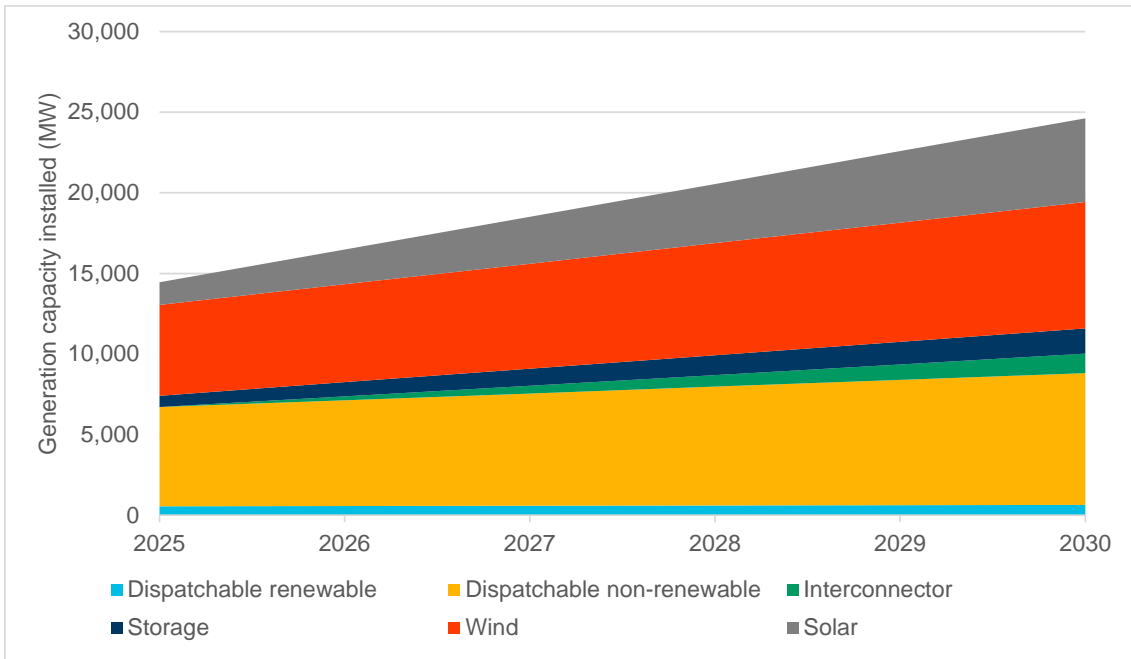


Figure 6.7 TSO and DSO connected and contracted generation capacity by type (MW) [connected: 14.5 GW; contracted: 10.2 GW]

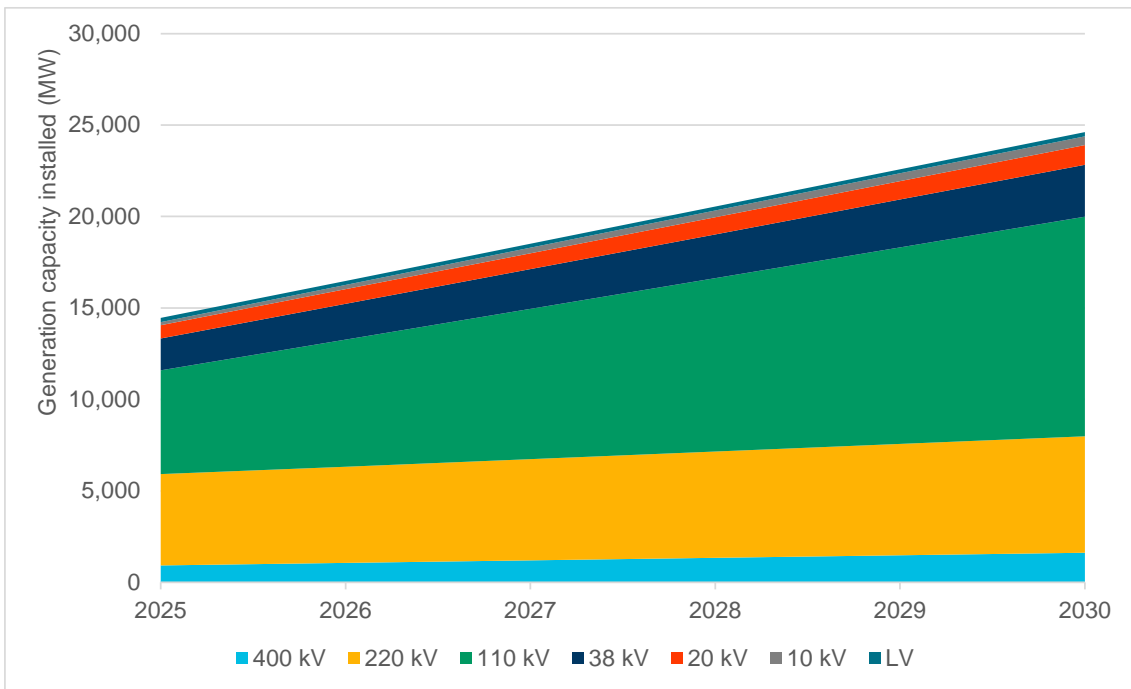


Figure 6.8 TSO and DSO connected and contracted generation capacity by connection voltage (MW) [connected: 14.5 GW; contracted: 10.2 GW]

Table 6.2 TSO and DSO connected and contracted generation capacity by type (MW)

Generation type	Connected	Contracted	Total
Dispatchable renewable	552	88	640
Dispatchable non-renewable	6,162	2,016	8,178
Interconnector	0	1,204	1,204
Storage	705	871	1,575
Wind	5,633	2,203	7,835

Generation type	Connected	Contracted	Total
Solar	1,400	3,782	5,182
Total	14,452	10,164	24,616

Table 6.3 TSO and DSO connected and contracted generation capacity by connection voltage (MW)

Connection voltage	Connected	Contracted	Total
400 kV	927	700	1,627
220 kV	4,987	1,367	6,354
110 kV	5,676	6,331	12,007
38 kV	1,747	1,086	2,834
20 kV	718	365	1,083
10 kV	172	313	485
LV	224 ⁷	2	226
Total	14,452	10,164	24,616

Figure 6.9 presents an illustration of the generation capacity headroom in 2025 and 2030 based on the system peak demand and generation capacity information presented in sections 6.1 and 6.2, respectively. This shows the overall increase in generation capacity installed (difference shown in grey between the inner bar for 2025 and outer bar for 2030), and the system peak demand shown in blue in each case. The system peak demand goes from 37.7% of the installed generation capacity in 2025 to 27.3% in 2030. This change in capacity margin is deemed to be appropriate in light of the fact that much of the additional capacity is provided by non-dispatchable renewable sources.

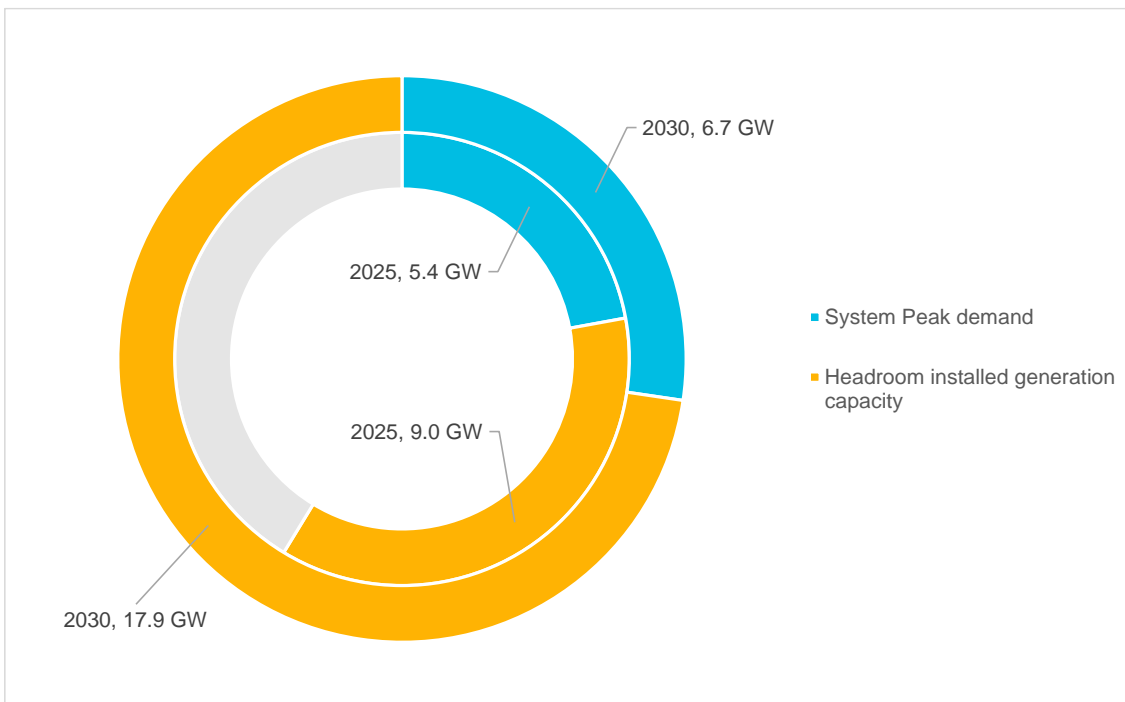


Figure 6.9 Generation capacity headroom 2025 and 2030

⁷ This value does not include 536 MVA of rooftop solar that ESNB has indicated was connected at LV by the end of 2024. The table is based on the published 'DSO Energised Renewable' and Non-renewable Generators Q4 2024' tables along with TSO published data.

6.3 Network Capacity

6.3.1 Substation Capacity in Ireland

From the Register of Distribution Assets taken from the 2023 Distribution Annual Performance Report, the ESNB existing installed transformer capacities are as follows:

- 220/110kV transformers: 2,500 MVA;
- 110/38kV transformers; 7,160 MVA;
- 110kV/MV transformers: 1,558 MVA
- 38kV transformers: 5,401 MVA

In addition, from the same source, the number of MV transformers on the system is as follows:

- 3-phase Pole mounted Transformers: 22,896
- 1-phase Pole mounted Transformers: 228,412
- MV Ground Mounted Substations: 23,789

It has not been possible to reconcile the above with the existing installed capacity determined from ESNB's 2024 Demand Capacity Heatmap data. Figure 6.10 presents the existing installed capacity of transformers, based on our analysis of data taken from EirGrid's TYS22 [74] and ESNB's 2024 Demand Capacity Heatmap data [75].

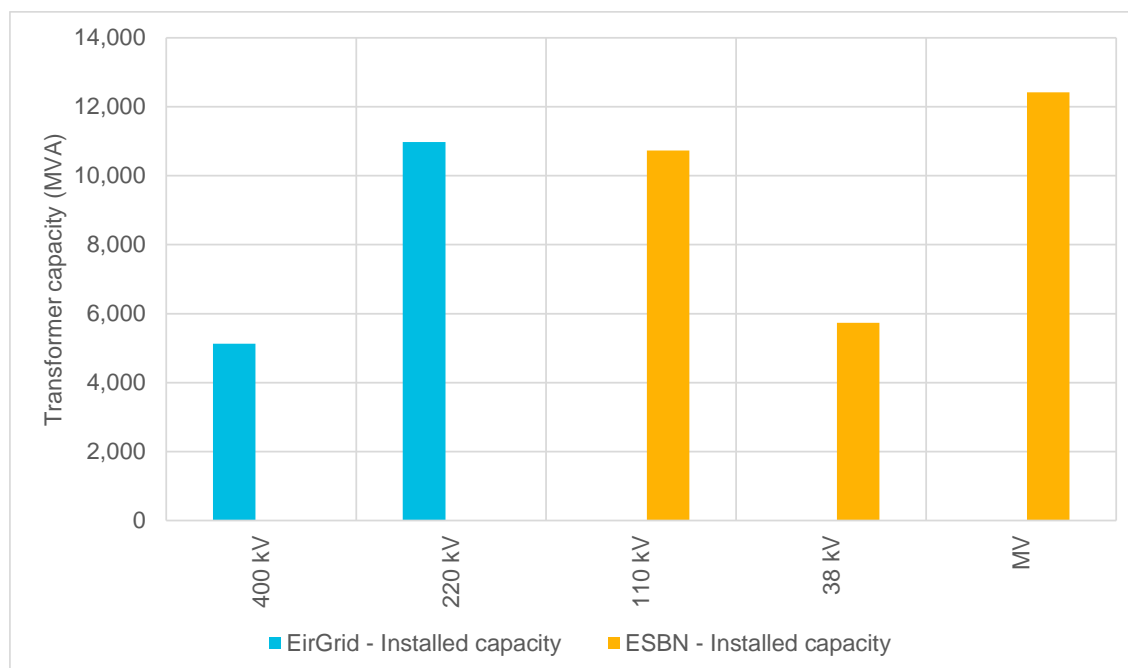


Figure 6.10 TSO and DSO installed transformer capacity (MVA) [TSO: 16,111 MVA; DSO: 28,777 MVA] [74] [75]

Figure 6.11 presents the installed transformer capacities determined using the heatmap data along with the MVA capacity additions proposed by the NCs, resulting from transmission projects (capacity to 'maintain SoS and minimise constraints' from projects with a 'Primary Asset Type' identified as being 'Station') and DSO HV station reinforcement projects (additional 110 kV transformer capacity plus firm capacity at MV from 38kV station projects). A total of 16,076 MVA of additional capacity is proposed to be provided during PR6 (installed capacity of transformers at 110kV and above, and firm capacity at MV associated with 38kV transformers).

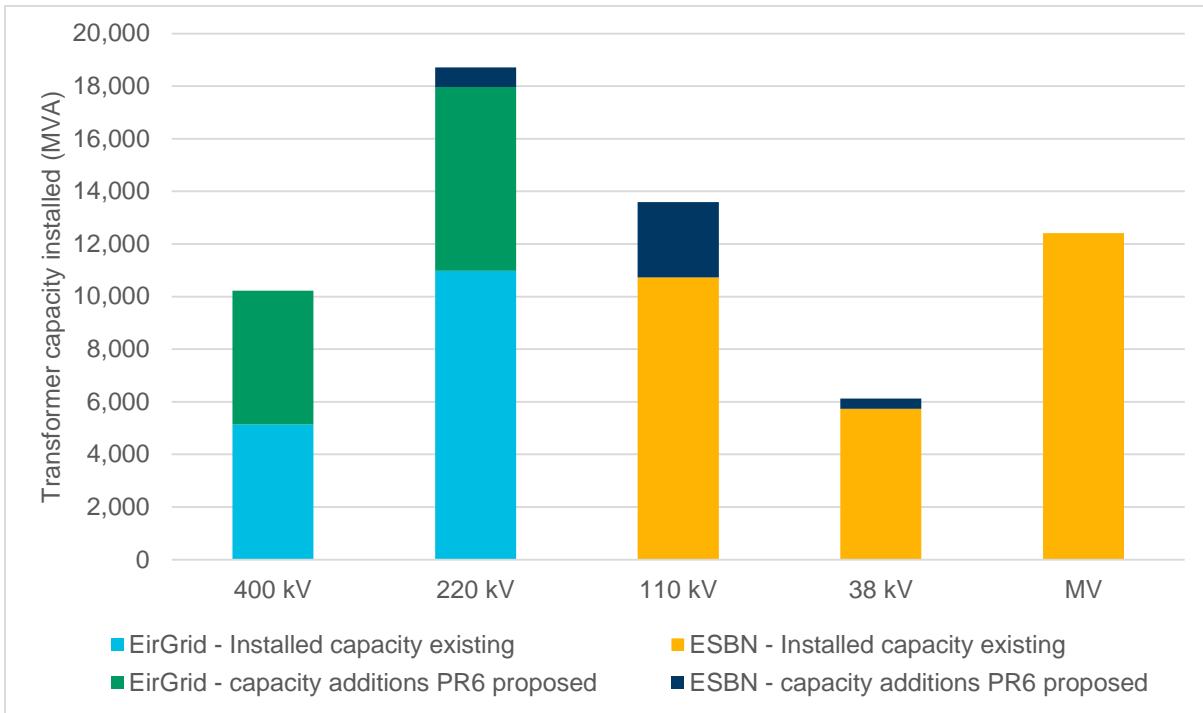


Figure 6.11 TSO and DSO installed transformer capacity and PR6 proposed capacity additions (MVA) [TSO additions: 12,077 MVA; DSO additions: 3,999 MVA]⁸

It should be noted that in the BPQ submission for network capex projects, the TSO also reported 4,354 MVA of transformer capacity additions for 110kV projects. This has been excluded from the above chart on the basis that the TSO does not have responsibility for 110kV station projects.

6.3.2 Capacity Headroom

Consideration of published capacity headroom provides a different means for assessment of the need for reinforcement to add capacity to the network, to supplement the analysis of the high-level installed substation capacity. Figure 6.12 presents the available firm capacity headroom from the ESBN Demand Capacity Headroom Report 2024 [76]. This is based on data presented for the available headroom for each of 621 substations under the 'best view' forecast scenario. The diminishing headroom over time corresponds to the impact of increasing demand across the network.

⁸ Note: 38kV and MV capacity additions have not been included, subject to confirmation of data.

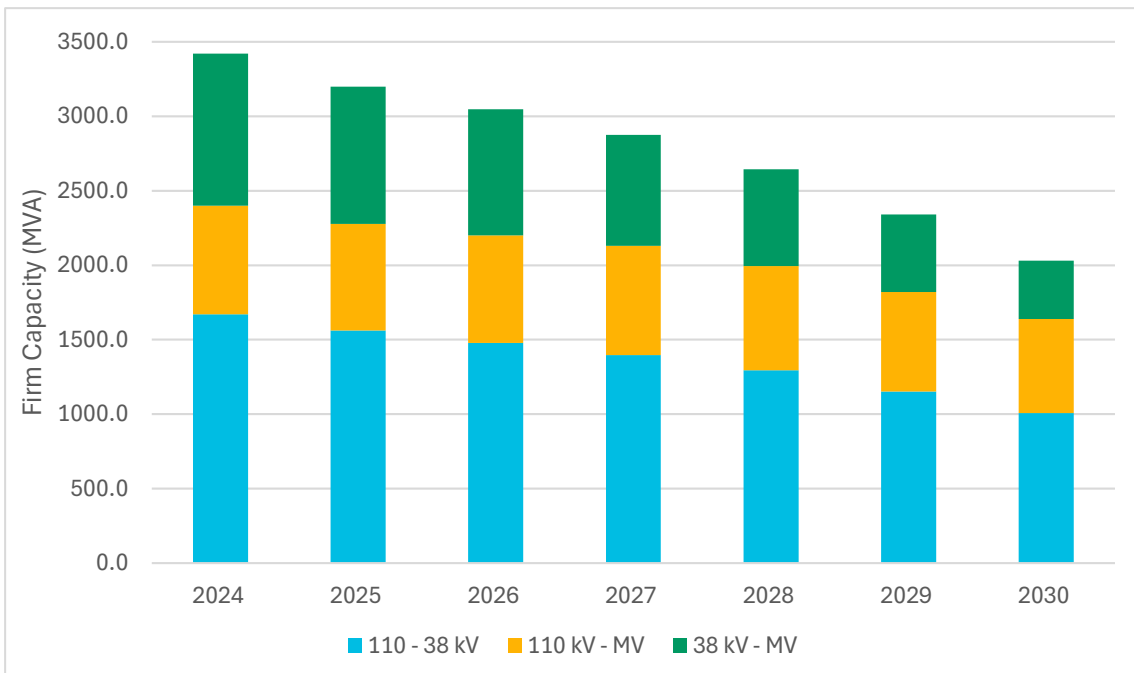


Figure 6.12 ESB Networks scenarios headroom capacity: available firm demand capacity (MVA) – best view scenario [76]

6.3.3 Constraints and Curtailments

Finally, the EirGrid Annual Renewable Energy Constraint and Curtailment Report 2023 [77] provides an indication of the ‘Dispatch Down’, or reductions in the amount of renewable generation compared with the available generation at different times through the year. Figure 6.13 presents the dispatch down, in energy terms, in each month of 2023 and 2024, split between constraints and curtailments.

The guidance from the report defines the elements of dispatch down as follows:

- Transmission (TSO) Constraints: Used to resolve a local network issue
- Curtailments:
 - i. High Frequency/Minimum generation: Used when attempting to alleviate an emergency high frequency event or in order to facilitate the minimum level of conventional generation on the system to satisfy reserve requirements, priority dispatch or to provide ramping capabilities,
 - ii. SNSP Issue: Used to reduce the System Non-Synchronous Penetration,
 - iii. ROCOF/Inertia: Used when the Rate of Change of Frequency (ROCOF) value for the loss of the largest single infeed is unacceptably high and wind/solar must be dispatched down as a result or when the system inertia is too low.’

The chart shows a variable picture of dispatch down, driven by the combination of network and weather conditions. It can be seen that dispatch down tends to be higher in December (around the time of system maximum demand), and can also be high in August (during the summer period where maintenance outages tend to be scheduled).

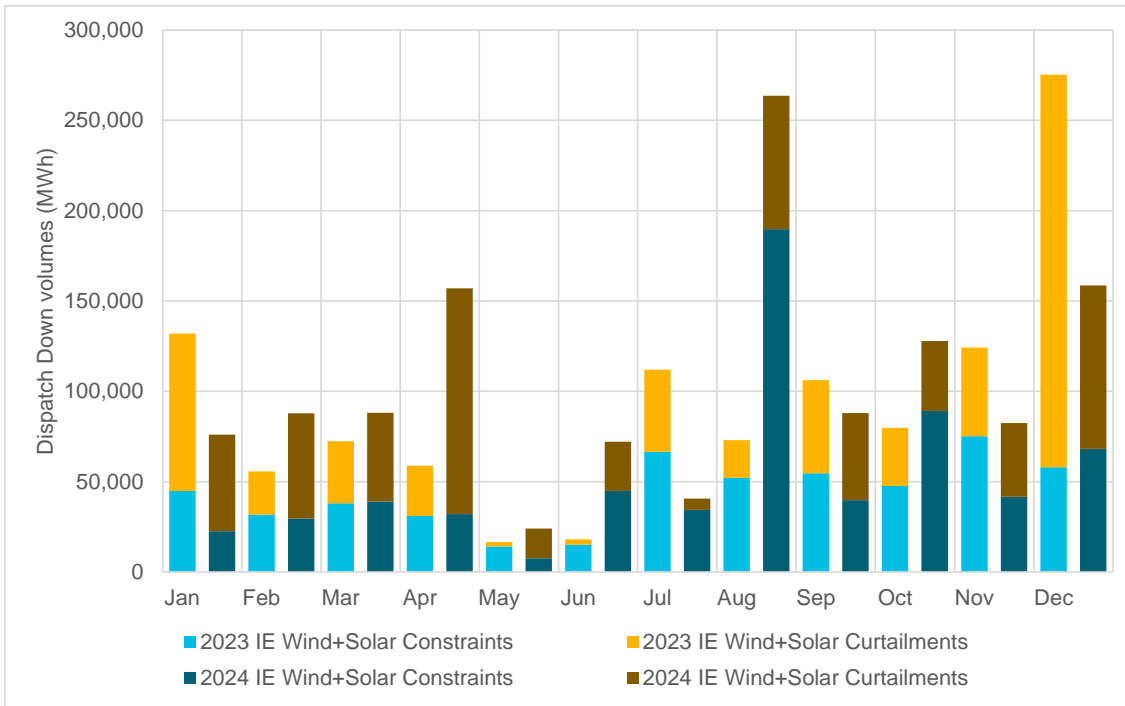


Figure 6.13 Dispatch down volumes 2023-24 [78]

Whilst the above charts provide an indication of the total available energy that is not used in each month, Figure 6.14 and Figure 6.15 re-present EirGrid’s published material showing plots of the daily dispatch down for wind and solar, respectively. It can be seen that the wind constraints reach a daily maximum of about 8,000 MWh in December, which corresponds to a continuous constraint of 330 MW for 24 hours. This value rises to approximately 28,000 MWh (1.2 GW) on one day in August.

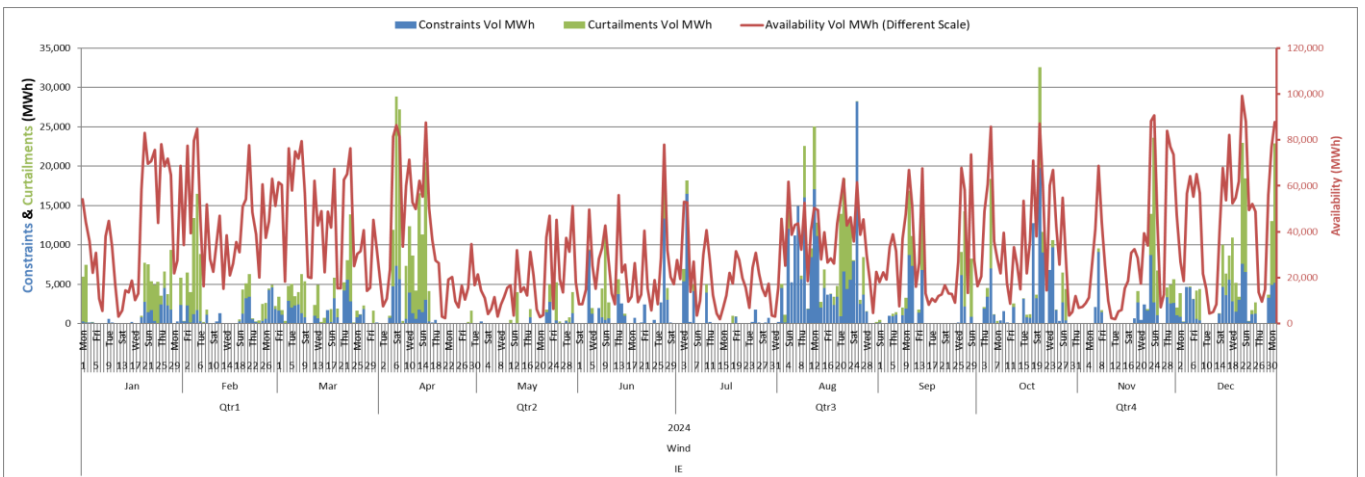


Figure 6.14 EirGrid Dispatch Down Summary Report - Daily 2024 IE wind dispatch down (constraints and curtailment) volume chart

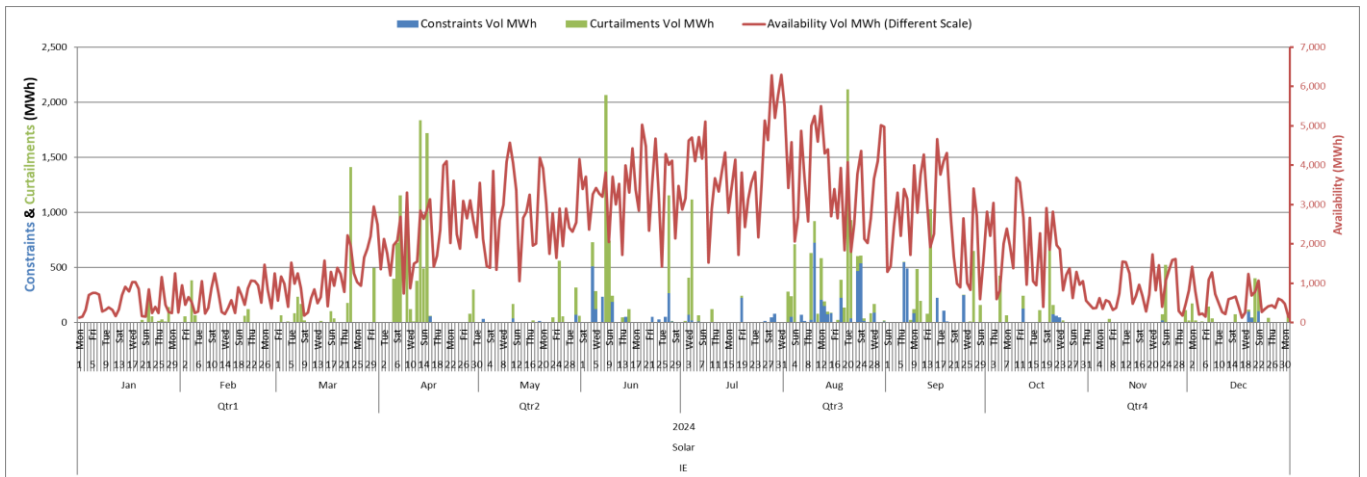


Figure 6.15 EirGrid Dispatch Down Summary Report - Daily 2024 IE solar dispatch down (constraints and curtailment) volume chart

Further to the above, the Draft Dispatch Down Action Plan was published by SONI in December 2024 and includes several recommendations to mitigate the high levels of dispatch down of renewables in Northern Ireland [79]. These recommendations include:

- Investing in and upgrading the grid infrastructure to accommodate higher levels of renewable energy and reduce bottlenecks.
- Advocating for supportive policies and regulations that facilitate the integration of renewables and address dispatch down issues.
- Enhancing forecasting and scheduling techniques to better predict renewable energy generation and optimise dispatch decisions.
- Developing and commissioning additional interconnectors, such as the North-South Interconnector, to improve energy flow and reduce dispatch down.
- Fostering collaboration among industry stakeholders, government, and regulators to develop and implement effective mitigation strategies.

These recommendations aim to create a more reliable and efficient power system that supports Northern Ireland's renewable energy goals. Many of these recommendations could also be applied to EirGrid's network.

6.3.4 Underinvestment in Previous Periods

The PR3 regulatory period, set in the aftermath of the 2008 financial crisis, led to substantial reductions in capital expenditure. The regulator's PR3 Final Determination approved less spending than ESB Networks had anticipated, deferring certain network projects and disallowing some expenditures due to the economic climate. In the early years of PR3, ESB Networks further reduced its capital investment programme in response to the ongoing economic downturn, with several factors contributing to this additional reduction.

Figure 6.16 reproduces a figure submitted by ESNB as part of the PR3 submission, subsequent mid-term review [80] and the ESNB's 'Response to CRU on cost assessment' as part of the PR6 engagement (dated 9 April 2025).

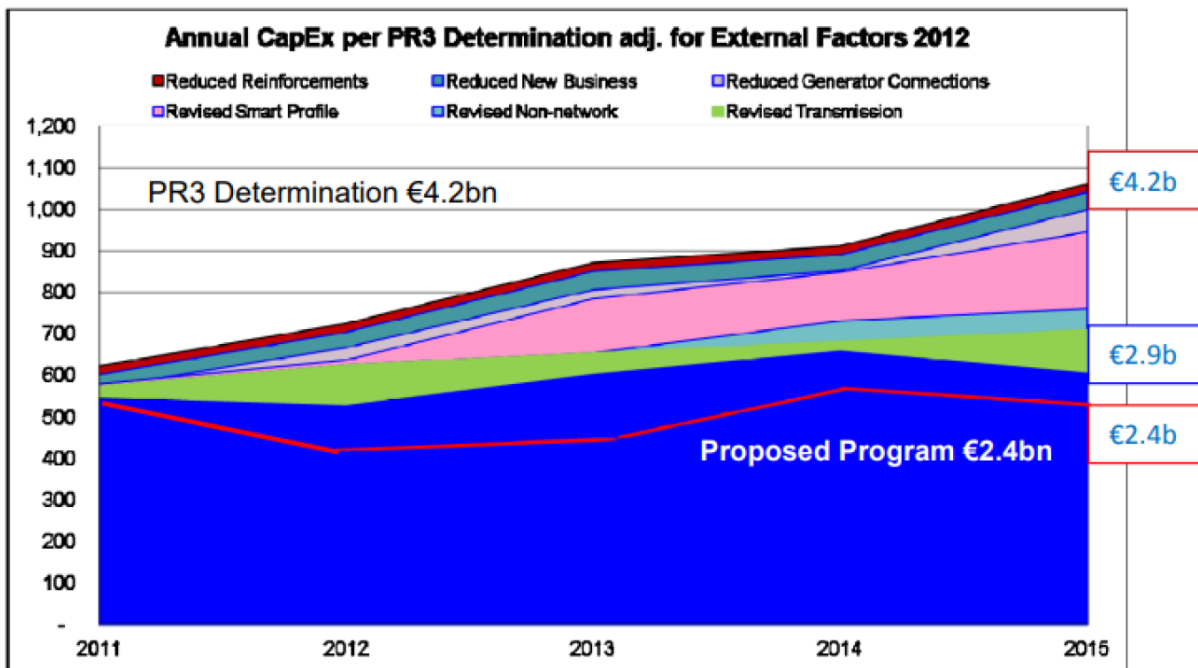


Figure 6.16 PR3 re-profiled capex investment programme

In summary, the capex reductions during PR3 introduced operational risks by deferring essential projects, which were acknowledged at the time. This led to a backlog of asset replacements and increased operating costs, meaning subsequent price controls would require significant capex to address deferred work and maintain efficiency.

In its 'Response to CRU on cost assessment', ESNB stated that 'economic growth during PR4 far outpaced the conservative assumptions used in setting those [load-related capex] allowances', which had been set 'with the intent to "recover lost ground from the PR3 deferral of necessary distribution investment"' [81]. ESNB notes that CRU accepted its reasoning that 'in plain terms, connecting new customers in PR4 cost more than budgeted (due to about 25% more connections than expected, among other factors), and those overruns were partially offset by underspends in other reinforcements and non-load related capital expenditure'. There remains a question about the long-term efficiency of delivery, which is being reviewed separately as part of work by CEPA and GHD for PR6. However, the constraints on investment applied historically are acknowledged, which is consistent with the need to catch up to overcome existing network constraints.

6.4 Load-related Investment Proposals

Figure 6.17-15 and Figure 6.18-16 present the cumulative actual and forecast spend on load-related capex across the PR5 and PR6 periods for the DSO and TSO & TAO, respectively. The total figures from the charts are also presented in Table 6.4. These charts show substantial increases in the forecast spend in PR6 compared with PR5 (DSO: 131%; TSO: 347% increases).

Whilst the increases in the proposed expenditure appear to be significantly higher than the forecast increase in the peak demand (discussed in section 6.1), in our professional opinion, we agree that the increases are in line with the requirements to provide approximately 16,100 MVA of additional substation capacity identified in section 6.3.1. This is expected to accommodate forecast demand increases, as well as to provide capacity for connection of approximately 10 GW of contracted generation, as discussed in section 6.2.

Table 6.4 Comparison of PR5-PR6 load-related investments

Licensee	PR5 actual and forecast	PR6 forecast	% increase
DSO	1,651.7	3,811.4	131%
TSO and TAO	1,328.4	5,938.8	347%

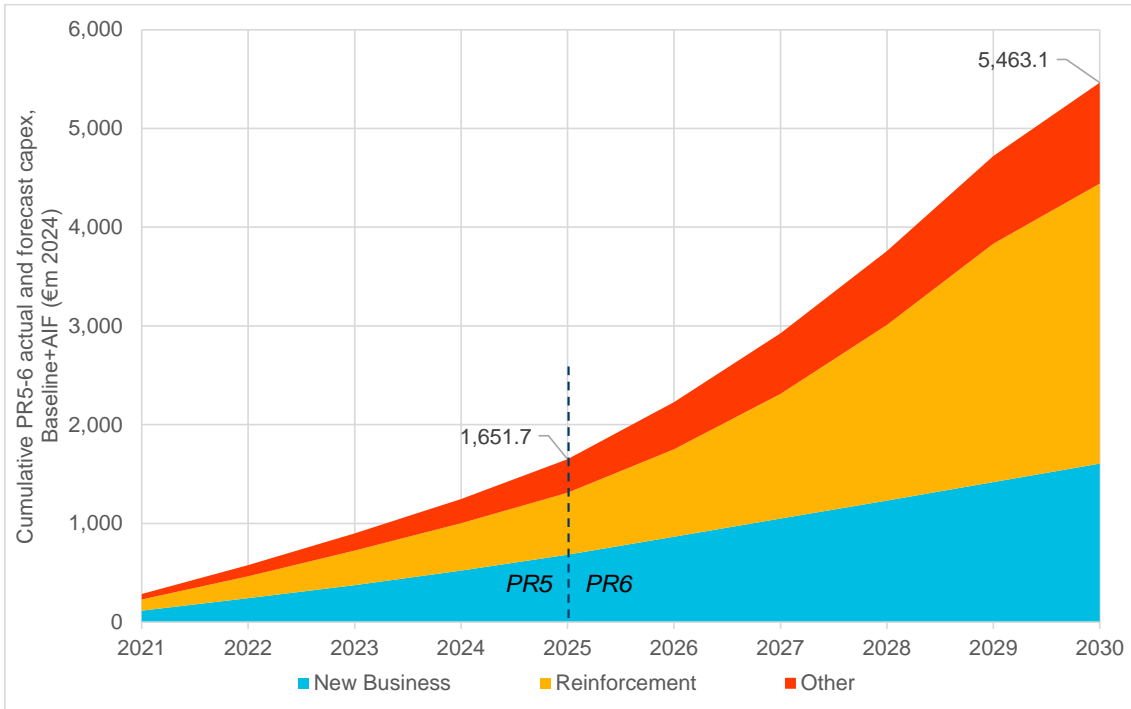


Figure 6.17 Comparison of PR5-PR6 DSO Load-related Capex

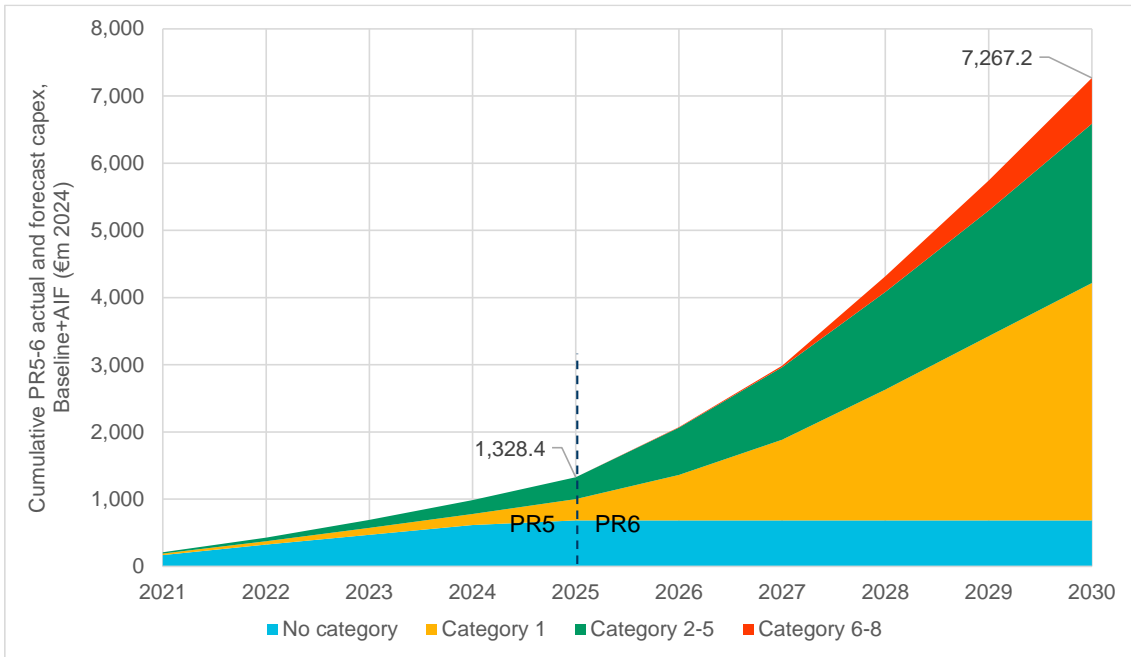


Figure 6.18 Comparison of PR5-PR6 TSO and TAO Load-related Capex

In addition to the above analysis, Appendix A presents details of the asset volumes proposed to be added to the network in PR6 compared with PR5. Overall, the load related expenditure forecasts, corresponding to net addition of assets to the system, appear to be consistent with meeting the forecast new connections, demand and generation whilst maintaining compliance with network security standards.

When comparing investment in the PR5 period with the PR6 proposed expenditure, the increase (131% and 347% for DSO and TSO & TAO, respectively) is higher than the forecast increase in the peak demand (9-36%, depending on the forecast scenario). However, in our professional opinion, we agree that the increases are in line with the requirements to provide approximately 16,100 MVA of additional substation capacity. This is expected to

accommodate forecast demand increases, as well as to provide capacity for connection of approximately 10 GW of contracted generation.

6.5 Innovation and Research and Development (R&D)

The electricity sector must undergo a fundamental transition, with innovation and research being crucial for harnessing a cost-effective route to Net Zero ambitions. Clear strategies for enabling innovation over PR6 are needed to address immediate challenges. Collaboration is essential to achieve carbon neutrality by 2050 and meet 2030 targets, enhancing our capabilities and processes.

ESB Networks is requesting a total opex allowance of €34.5m to support innovation and electrification activities in PR6. This is a 53% step up from PR5 during which it spent €22.5 across the period (2024 prices). Table 6.5 sets out ESB Networks' innovation focus for PR6. The outputs of the innovation projects outlined will support finding new smart, whole system solutions that reduce pressure on capex plans through opex solutions.

Table 6.5 ESB Networks Innovation Focus for PR6

Project	Description
ElectriCITY	Addressing urban electrification challenges, supporting vulnerable and energy-poor customers.
Electrification	Optimising EV charging, vehicle-to-grid solutions, and innovations for heavy goods vehicles and heat flexibility.
Network capacity and flexibility	Expanding capacity and delaying reinforcements through smart solutions, including upgrading networks and flexible connections.
Network resilience, reliability, and safety	Projects to improve continuity, resilience, and climate risk mitigation, including wildlife protection, cybersecurity, and fault repair.
Decarbonised electricity	Assessing hydrogen electrolyzers and replacing carbon-intensive fuels in network operations and island communities.
Environmental sustainability	Developing projects in circularity, biodiversity, and regeneration to enhance sustainability.
Digital and data	Exploring digital solutions, open data, AI, and AR/VR innovations for transformation.
Empowering and protecting customers	Innovative solutions to support and empower energy communities.

EirGrid also published an update to its Innovation and Research Strategy, in collaboration with SONI, in December 2023 [82]. This Innovation and Research Strategy aims to boost innovation by establishing support structures and frameworks. EirGrid and SONI aim to decarbonise the all-island power system while ensuring reliable electricity supply, with a goal of achieving up to 80% renewable energy by 2030. Their refreshed Innovation and Research Strategy focuses on 'closing the gap' by fostering collaboration across various stakeholders to overcome challenges and meet government targets.

The Innovation and R&D Mechanism sought to provide the revenues needed to fund innovative projects that cannot be funded through ex-ante allowances or other mechanisms in the AIF in PR5. As part of the annual requirements for reporting on innovation, EirGrid were able to submit a business case to request additional funding for innovative projects. Such business case documents are required to include a rationale for why the project is innovative, the potential benefits and a description on how the project will be reported on, managed and evaluated. It is proposed that progress on innovative projects will continue to form part of the Annual Innovation Report, which EirGrid consults on and submits to the CRU. The companies also publish the report, with the latest being the 2023 Annual Innovation Report [83]. This annual report is a key deliverable as part of the PR5 framework.

EirGrid's 2023 Annual Innovation Report highlights several key achievements from their innovation and R&D efforts. They successfully delivered projects such as the 'Shaping Our Electricity Future Roadmap' and 'Tomorrow's Energy Scenarios'. The Shaping Our Electricity Future Roadmap outlines the steps needed to modernise the grid, enhance system operations, and improve market designs to support the goal of achieving 80% renewable energy by 2030.

Tomorrow's Energy Scenarios explores various pathways for Ireland's energy transition, projecting electricity needs and potential solutions up to 2050. This initiative helps guide strategic planning and policy development to ensure a sustainable and secure energy future.

It is important that the regulatory framework supports innovation over the period, but ensures that the outputs and knowledge from projects are disseminated and integrated into business-as-usual in a timely manner, where appropriate. Without this, there is a risk that innovation funding becomes futile. From an electricity networks perspective, this approach ensures that innovative solutions are efficiently incorporated into the grid, enhancing system reliability and performance. It also maximises the benefits of innovation funding by addressing broader energy challenges, supporting the transition to Net Zero, and ultimately delivering cost savings and improved service quality for consumers.

6.6 Resource and Deliverability

The PR6 workforce resilience strategy for ESB Networks outlines a plan to scale up and prepare the organisation for significant delivery demands required to enable the decarbonisation of Irish society. ESB Networks aims to have a workforce capable of meeting PR6 targets, with a detailed analysis of the current workforce and future needs. The strategy emphasises the importance of having the right size and skilled workforce, creating a positive and inclusive work environment with safety, technical excellence, and operational efficiency at its core.

Growth in the internal workforce has been achieved, with the number of employees increasing by 16% since the start of PR5. For PR6, ESB Networks plans to scale up resourcing in critical areas such as electrical craft and line workers, engineering, and business support functions. The number of internal Network Technicians is expected to increase to 1,800, with recruitment underway to hire qualified electricians and apprentices. Other key functions indirectly involved in fieldwork, such as network planning, design, contract management, and business support, will need to grow sustainably. The strategy includes developing key enabling capabilities, such as operations and Persons in Charge of Works (PICWs), to ensure safe and efficient work delivery.

The national training centre has revised its technical training strategy to enhance trainee experience and improve knowledge transfer. ESB Networks said it will continue to recruit high-quality graduate engineers and quantity surveyors, focusing on areas of most value to the PR6 programme and customers. Leadership development programmes will equip supervisors and managers with the skills needed to guide the workforce through changes during PR6.

ESB Networks states that it will work closely with strategic contracting partners to increase the number of field workers and ensure better visibility on work volumes and types. This will be important given the relative step-up in the capex plan for PR6. Workforce resilience risks have also been identified, including recruitment and retention challenges, training and development needs, aligning workforce capabilities with future demands, business transformation, and diversity in the workforce. Mitigation strategies have been developed to address these risks, ensuring operational continuity and resilience.

EirGrid faces a significant capacity and capability gap as it transitions to PR6, with a top-down assessment showing it requires a 43% increase in the internal workforce by 2030, with internal FTE numbers projected to rise from 626 to 1,039. Adequate provisions for labour and non-labour costs are necessary to meet increased FTE and IT requirements, with annual wage growth of 3.86% above HICP inflation in labour costs and 3.17% above HICP inflation in non-labour costs deemed necessary.

EirGrid's comparison against market level trends suggests a divergence in its labour market offering compared to other employers, leading to recruitment and retention problems.

Focus areas in EirGrid's workforce resilience plan include building out capacity and capability to meet emerging and future obligations, ensuring value for customers through sustainable recruitment, efficient leveraging of external resources, and implementing process and system changes for more efficient operations. This strategy aims to address the critical juncture in the green transition and ensure EirGrid can meet its ambitious targets and obligations effectively.

The regulatory framework will need to be flexible to allow for the workforce to be scaled up so that capex plans are deliverable. The framework will also need to balance the cost of recruiting, training, and retaining internal staff

versus the ease of using contractors to scale-up deliverability quickly. Undoubtedly, contractors will be an important aspect of ensuring the right skillset is available at the right time. However, continual training programmes should not be lost sight of as they will be important to make sure the workforce remains resilient. Ensuring deliverability in the step-change in plans requires a regulatory framework that can adapt to the dynamic needs of scaling up the workforce. This includes provisions for both internal staff development and the strategic use of contractors to meet immediate demands. While contractors offer a quick solution to scaling up deliverability, the long-term resilience of the workforce depends on robust training programmes that continuously develop internal capabilities. Balancing these elements will be crucial for the PR6 investment programmes to be delivered.

7 Delivering Investment Efficiently in PR6

The changes being experienced by the electricity system, resulting from electrification of heat and transport, accommodation of new connections and greater non-synchronous generation capacity, mean that the requirement for robust investment planning is more important than ever. This suggests a more proactive and efficient planning approach is necessary. The extent of the challenge should be recognised to enable proactive investment decisions to be made, based on rigorous analysis to reduce the risk of regret from such decisions.

The UK National Infrastructure Commission (NIC) has recently published a report on ‘Electricity distribution networks: Creating capacity for the future’ [84], which states that:

- ‘Continuing a steady state approach will not be sufficient to meet future demand or deliver benefits, such as enabling economic growth and development’;
- ‘Encouraging proactive investment requires a new system of managing, regulating and upgrading our distribution networks’; and
- There is a need for ‘greater strategic planning... that take account of a wider range of objectives’.

The following sections explore the importance of strategic investment in the context of the challenges set out above, and considerations relating to preparation of robust CBAs to ensure that investments are efficient and well-justified. Furthermore, it also presents details of the Energy Efficiency First Principle (EEFP), which will require energy efficiency to be considered once it is fully implemented under the EU Directive. This section also compared the infrastructure efficiency-related incentives that exist in different regimes across Europe.

7.1 Strategic Planning and Investment

To overcome potential technical and regulatory challenges as well as increased forecasted demand, as described in sections 2 to 5, and deliver a network that best meets the needs of its users, NCs’ business plans should be planned so that investments align with the evolving landscape by investing in the right projects at the right time. The justification of these investments has shifted from historically focussing on certain needs to focussing on more anticipatory needs. Without this, the network risks being ill-prepared for future growth and challenges.

However, this must be balanced by a rigorous process, ensuring that interventions are properly justified and that non-network solutions are considered and utilised where appropriate, so that consumers are not paying more than is required. Therefore, the planning prior to a new price control period and the regulatory mechanisms available to allow for flexible adjustments to allowances in-period are imperative.

Investment to increase capacity to meet increased demand has a well-established premise within the regulatory framework. However, NCs should also consider the following in strategically planning interventions on the network:

– Provide capacity headroom

Investing in electricity network headroom capacity is crucial for several reasons, particularly in the context of the ongoing transition to a more sustainable and resilient energy system.

Firstly, the electrification of heat and transport is a key component of decarbonisation efforts. As industries, homes, and vehicles shift from fossil fuels to electricity, the demand on the electricity network increases significantly. Maintaining, or the creation of, headroom will help encourage consumers and industries to transition to these new technologies. Without adequate headroom capacity, the NCs could be seen as a barrier to technology adoption, with the network struggling to accommodate these new loads, leading to reliability issues and potential outages.

Secondly, the shift from large centralised generation to intermittent renewable generation poses unique challenges. Traditional power plants, such as coal and nuclear, provide a stable and predictable output. In contrast, renewable sources like wind and solar are intermittent and variable. This variability means that additional capacity is needed to ensure a consistent supply of electricity, as renewables cannot always deliver the same base load as their fossil fuel counterparts. Investing in headroom capacity allows the network to better manage these fluctuations and integrate a higher proportion of renewable energy, supporting the transition to a cleaner energy mix.

Furthermore, creating additional capacity in the electricity network is a time-consuming process. Reinforcement projects often involve complex planning, regulatory approvals, and significant financial investment. The lengthy timelines can be attributed to the need for meticulous design, environmental assessments, and coordination with multiple stakeholders. Therefore, proactive investment in headroom capacity will help the network meet future demands without incurring significant delays.

– **Facilitate economic growth**

Economic growth is driven by the expansion of commercial/industrial activity and housing, which require connection to the electricity network. Thus, the electricity network should be prepared to support this growth and avoid becoming a bottleneck. NCs are responsible for enabling and facilitating new connections in a timely manner, thereby promoting sustainable development and fostering a thriving economic environment without compromising the quality of supply for existing customers. By proactively addressing future needs, NCs can capitalise on economic growth to expand their customer base and enhance their service offerings, while incorporating strategies in coordination with regulators for the protection of consumers and minimisation of the magnitude of increases in their bills.

– **Optimise existing capacity**

To meet the growing demand whilst remaining efficient, operators should focus on maximising existing network capacity, partly through flexibility services and advanced data management. Flexibility services, such as demand side response (DSR), can help manage peak loads effectively and help minimise network stress. Additionally, DERs connected to the network has already increased significantly in recent years. This trend is forecast to continue with more solar and wind energy projects awaiting connection. As part of this, prosumers will be exporting surplus electricity back to the grid. For the network assets to be prepared for these changes, strategic network plans should include new technologies that will allow for real-time adjustments and ultimately expedite the integration of new renewable electricity capacity.

Well-planned strategic investment is essential for meeting decarbonisation targets and ensuring a resilient, efficient, and future-proof electricity system. While part of the solution will be to increase the physical asset base through increased capex, strategic investment should also include consideration of existing capacity

Figure 7.1 provides an illustration of the steps required for strategic network planning. Whilst many of the principles have been adopted historically, it is now more important to ensure that there is sufficient rigour in the analysis carried out in each of these steps. The outputs from the first three steps should be captured as part of a comprehensive Cost Benefit Analysis, which should accurately represent the impact of a genuinely considered, credible range of alternative options, including non-technical solutions such as flexibility and energy efficiency measures.



Figure 7.1 Illustration of steps for strategic network planning

7.1.1 Considerations for a Robust CBA

A CBA is a decision-making tool that is used to compare alternative options through an economic assessment to justify an investment decision in a particular intervention, based on modelling of the long-term costs and benefits. This is particularly useful on the backdrop of increasingly complicated network investment plans. Using CBAs to clearly justify interventions and show that other interventions have been considered will reduce the risk of unnecessary investment and offer best value for money for customers.

A CBA provides information on the options that have been considered and provides an understanding of the key assumptions that have been made. For example, a CBA can be used to demonstrate how the costs and benefits of an energy efficiency intervention compare with an equivalent traditional solution. While some CBAs were submitted as part of the PR6 process, for a CBA to be useful in the context of strategic investment, adherence to good practice should be monitored and maintained. A guideline of good practices for a NC CBA is set out below.

7.1.1.1 Two-step approach

The following two-step approach is recommended to be adopted:

Convert capital costs into annual costs using the company's cost of capital;

Use a Social Time Preference Rate (STPR) (e.g. 3.5%) to discount all costs and benefits (except safety where the Health Discount Rate (HDR) should be used).

To convert capital costs into annual costs recovered through customers' bills, a pre-tax weighted average cost of capital (WACC) figure, consistent with business plan assumptions, should be used.

Costs and benefits should be extended from the start of investment to cover a period consistent with a long-term time horizon, which represents the useful economic life of the interventions being considered. Costs and benefits should be discounted over this period, with a specified base year (currently 2024).

7.1.1.2 Identification of options

The NC should clearly identify the range of options that were considered to meet the stated aim. This list should include a long list of all options considered, including the options rejected before full costing and why they have been rejected.

This list should, where feasible, include a baseline scenario option that requires minimal initial investment to comply with relevant legislation against which other options can be compared. This should be compared with a set of alternatives, which have been identified through genuine consideration of the broad range of available options including non-technical solutions such as flexibility and energy efficiency measures.

7.1.1.3 Valuing the cost and benefits of options

For the short-listed options, costs and benefits to be considered in the CBA are those that would occur over and above the baseline scenario. These additional costs and benefits represent the marginal or incremental costs or benefits of the option being considered.

All negative impacts of an option should be captured as costs and all positive impacts as benefits.

The financial costs and benefits should correspond to the market values assumed in the NC's business plan, e.g. a reduction in repair and maintenance costs arising from an investment should be consistent with unit repair and maintenance costs set out in the plan.

The NC should also include replacement costs for the particular assets specified which may need to be replaced during the time horizon. The NC should include assumed failure rates of assets, setting out its view and explaining the assumptions made as part of this assessment.

Financial costs should be in a specified price base (currently 2024), exclude any inflation or Real Price Effects (RPEs), and be net of expected productivity improvements.

Options should demonstrate that flexible solutions/ services have been considered where applicable, with appropriate consideration of the costs and benefits on an equivalent basis.

7.1.1.4 Social benefits

The NC should consider societal benefits (i.e. avoided costs) associated with each option. Specifically, key environmental, safety and other drivers that support many investment decisions should be included in the CBA. Examples include, but are not limited to:

- Energy efficiency benefits;
- Losses;
- CO₂e associated with losses;
- Other GHG emissions;
- Fatality and major injuries; and
- Customer interruptions and customer minutes lost.

Where possible, assumptions on societal benefits should be agreed upfront and standardised across all CBA templates. Where this is not possible, justification should be provided on a case-by-case basis as to why the societal benefit has been included and the methodology used for calculating the benefit. Workings should be provided as to how the benefit was calculated.

7.1.1.5 Decision making

Positive NPVs indicate a project should be undertaken with a positive net benefit to consumers.

However, when a scheme has a slightly positive or negative NPV, the NC should evaluate whether to include or exclude it by using sensitivity analysis and identifying any non-monetised benefits or costs. For instance, such non-monetised costs/benefits might involve engineering judgement on what constitutes an efficient project, for example as an enabler for further interventions that provide benefits.

The NC should also consider sensitivity analysis for key assumptions used in its CBA, for example:

- Asset performance / health deterioration rates;
- Ongoing efficiency assumptions;
- Future demand growth / reduction;
- Future energy scenarios; and
- Future utilisation of assets.

7.2 Energy Efficiency First Principle

The Energy Efficiency First (EEFP) principle is a pivotal element of the EU's energy policy, emphasising the prioritisation of energy efficiency in all planning, policy and investment decisions. As such, it mandates that efficient measures, including energy savings and demand response mechanisms, are given a fair chance with respect to other energy solutions during the decision-making process of an energy system's development.

The revised EED (EU/2023/1791) provides a stronger legal basis for the application of the EEFP principle, setting an obligation for all EU countries to ensure that energy efficiency solutions are prioritised. The directive instructs that energy efficiency must be considered for high-value projects in both energy and non-energy sectors, supported by regular reporting and compliance monitoring.

Implementing EEFP in the energy sector involves conducting cost-benefit analyses with a broader scope, taking into account the multiple impacts of both demand- and supply-side options under consideration. This further enhances the importance of a consistent, integrated and whole system methodology to be utilised by operators during their planning processes. The suggested approach not only seeks to capture the system-wide needs, but also provides the foundation for long-term decisions in light of uncertainties, while aiming to reach the decarbonisation targets. It is to be fundamental to the five dimensions of the EU Energy Union (decarbonisation, energy security, energy efficiency, internal energy market, and research, innovation and competitiveness) to highlight the most efficient solutions across the broad value chain.

For regulatory authorities, the EEF principle notes a significant shift in how energy policies and projects are evaluated, and consequently how their corresponding resources are allocated. Regulators are tasked with ensuring that CBA methodologies that include a proper evaluation of the wider benefits and costs of energy efficient solutions (from a societal perspective) are being developed and applied.

For the CRU specifically, EEF is to be included in any consideration of energy infrastructure spending with investment costs of over €100M for energy projects (€175M for transport infrastructure projects), subject to change following a review in 2027. Energy efficiency alternatives that meet the same objectives as a given investment should be assessed and considered, but such alternatives can be rejected if reasonably justified for other reasons.

Examples of key CRU decisions we have identified in the Strategic Plan 2022-24 relating to EEF [85]:

- Price controls (electricity/gas/water), as TSO/DSO revenues exceed the €100M threshold;
- Network tariffs (electricity & gas);
- Approval of network development plans (electricity & gas);
- National Energy Demand Strategy;
- Market-related decisions – capacity market, DS3; and
- Connections policy (electricity & gas, water).

In terms of guidance for what should be expected from NCs in preparing CBAs to fulfil the requirements of EEF, this centres around the identification and appropriate evaluation of options to demonstrate that energy efficiency solutions have been considered. The rationale for energy efficiency solutions is similar to that for flexibility, whereby smaller upfront and/or annual costs are assessed to provide benefits that avoid or defer a larger investment in network infrastructure. This should be reflected in a comprehensive CBA, which incorporates quantitative assessment of the technical impact of the energy efficiency solutions (reduction of peak demand, energy consumption/losses).

Whilst the overall revenues under the price control exceed the €100m threshold, it would be reasonable to consider energy efficiency solutions as alternatives for individual initiatives or schemes. In these cases, it should be noted that €100m is a relatively high threshold for investment, and network projects of such scale would typically be difficult to offset wholly with energy efficiency solutions. It is noted that considerations related to EEF (including the €100m threshold) are subject to review in 2027, and this may present an opportune window to re-evaluate the threshold and the impact of this on individual investment initiatives. This review might look to establish clear guidelines for PR7 (and any in-period reviews, should they be deemed to be required).

For future Business Plan submissions, it is recommended that NCs should be required to submit a holistic network development planning assessment (incorporated with current NDPs), to demonstrate the overall approach to consideration of energy efficiency solutions. Comprehensive CBAs should also be developed, based on quantitative modelling following the guidance set out in section 7.1, for individual schemes that exceed the threshold or lower value schemes where energy efficiency could be considered to provide a viable alternative.

7.3 European Regulatory Frameworks

The design of efficient regulatory mechanisms for electricity distribution systems needs to account for well-known and new challenges, including asymmetry of information, the integration of distributed energy resources and the adoption of advanced information and communication technologies.

Traditionally, price controls separate capex and opex allowances. This is true for many of the regulatory frameworks across Europe, which apply a 'building blocks' approach. However, to respond to the modern challenges faced by networks, some regulators have taken different approaches.

For example, in Great Britain, Ofgem apply a totex (total expenditure) approach. Totex models promote a comprehensive approach to decision-making. They enable the consideration of both capex and opex solutions in a complementary way. While capex investments in the grid remain crucial as electricity demand increases, flexible solutions can assist system operators in making more precise decisions about where and when to invest. This approach ensures investments are made in the most beneficial locations, maximising value to consumers. By integrating flexibility with necessary grid reinforcements, system operators can optimise their existing networks and

expedite the journey to Net Zero. Giving equal weight to opex encourages system operators to select the most economically efficient solutions to address constraints.

Allocating investments in the most economical way, particularly considering their impact on consumers, can be achieved by designing an appropriate price control framework. Table 7.1 sets out the existing infrastructure efficiency related incentives across Europe and indicates that incentive-based regulation is commonly used, but it remains largely traditional, with the 'revenue-cap' approach being the most prevalent. In most jurisdictions, the regulation of capex and opex is now aligned, with a revenue cap applied to both, albeit separately [86]. This alignment helps reduce the capex bias in the regulatory approach. However, a totex-based framework, which ensures a fully symmetric and consistent treatment of capex and opex, is currently implemented in only a few countries, such as Great Britain and Portugal. Italy has also started introducing totex-based regulation for electricity transmission in 2024. Other methods to mandate non-network solutions outside of a totex model include Performance-Based Regulation or requiring a Cost-Benefit Analysis. The table shows other jurisdictions also have performance-based and benefit-based incentives to supplement their regulatory approach, with many mandating CBA to justify investments.

Table 7.1 Mapping of existing infrastructure efficiency-related incentives in Europe applied to transmission

Country	Regulatory approach to Opex	Regulatory approach to Capex	Performance-based incentives (PBI)	Benefit-based incentives (BBI)
Austria	Cost-plus	Cost-plus	WACC adder to promote investments in the TYNDP29	
Belgium	Revenue cap	Rate of return	On asset availability	
Bulgaria	Rate of return	Rate of return		
Croatia	Cost-plus	Cost-plus		
Cyprus	Revenue cap	Revenue cap		
Czech Republic	Rate of return	Revenue cap		
Denmark	Cost-plus	Cost-plus		
Estonia ³³	Rate of return	Rate of return		
Finland	Revenue cap	Revenue cap		
France	Revenue cap	Cost-plus (for investments in 'network' projects) Revenue Cap (for investments in 'non-network' projects: information systems and real estate)		
Germany	Revenue cap	Revenue cap		
Great Britain	Revenue cap (on TOTEX)			
Greece	Revenue cap	Cost plus		
Hungary	Price cap	Price cap		
Ireland	Revenue cap	Rate of return	On investment planning and delivery, project delivery (for transmission asset owners), for RES integration	
Iceland	Revenue cap	Revenue cap		
Italy	Totex			For increases of cross-zonal transmission capacity, for investment cost efficiency, for

Country	Regulatory approach to Opex	Regulatory approach to Capex	Performance-based incentives (PBI)	Benefit-based incentives (BBI)
				quality of supply (energy not supplied)
Latvia	Revenue cap	Revenue cap		
Lithuania	Price cap	Price cap		
Luxembourg	Revenue cap	Revenue cap		
Netherlands	Revenue cap	Revenue cap		
Northern Ireland	Revenue cap	Revenue cap		
Norway	Revenue cap	Revenue cap		
Poland	Cost plus	Rate of return		
Portugal	Revenue cap (on Totex)		To improve technical performance of the network	
Romania	Revenue cap	Revenue cap		
Slovakia	Price cap	Revenue cap	WACC adder for innovative investments	
Slovenia	Revenue cap	Revenue cap	Some transmission investment linked to key performance indicators, voltage quality	For smart grids
Spain	Rate of return	Rate of return		
Sweden	Revenue cap	Revenue cap		

The regulatory framework for PR6 is likely to continue to follow a 'building blocks' approach, with capex and opex assessed separately. However, it is important that the CRU considers utilising other levers within the regulatory framework to incentivise strategic investment, for example choosing opex over capex solutions when this is appropriate.

7.4 Other Considerations for the PR6 Regulatory Framework

At a high level, the significant step increase in requested allowances can be justified by the need to meet energy sector targets and accelerate the net zero transition through addressing existing constraints to connect more renewable generation, as well as to accommodate increases in system demand and connection volumes resulting from economic growth. Overall, the load-related expenditure forecasts, corresponding to net addition of assets to the system, appear to be consistent with meeting the forecast new connections, demand and generation, as well as to address existing capacity constraints.

The proposed investments for PR6 face several key challenges that must be addressed to ensure successful implementation and achievement of the desired outcomes.

- **Step-change in capex programme:** When comparing investment in the PR5 period with the PR6 proposed expenditure, the increase (increases of 131% and 347% for DSO and TSO & TAO, respectively) is higher than the forecast increase in the peak demand (9-36%, depending on the forecast scenario). However, in our professional opinion, we agree that the increases are in line with the requirements to provide approximately 16,100 MVA of additional substation capacity. This is expected to accommodate forecast demand increases, as well as to provide capacity for connection of approximately 10 GW of contracted generation.
- **Deliverability:** The significant step change in proposed expenditure raises concerns about the deliverability of the projects. There is a risk that projects will spill over from PR6 into PR7. Increased transparency is required for deliverability across the portfolio of projects.

- **Resource Allocation:** Ensuring that sufficient resources, including skilled labour, materials, and equipment, are available to meet the demands of the projects. This may involve scaling up the workforce, securing supply chains, and managing logistics effectively.
- **Uncertainty:** The capex assessment carried out for the PR6 Draft Determination revealed that uncertainty is a strong feature of the business plans for PR6, and the plans submitted do not address in detail how the uncertainty will be properly managed and monitored to protect the consumer (apparent blanket approach to application of AIF). In the case of transmission, capex proposals are based on completion of projects in accelerated timescales. In the case of distribution capex, ESB Networks has advised recently that quantitative risk adjustment factors have been applied to account for uncertainty related to progression of individual projects.

Despite the challenges, the proposed investments also present several opportunities that can drive positive outcomes for Ireland's electricity network:

- **Provide capacity headroom:** Proposals to provide additional network capacity, overcoming existing constraints, are key to supporting the ambition to electrify heat and transport and accommodate additional volumes of intermittent renewable generation to contribute to decarbonisation. Additionally, it is necessary to address the historic underspend in network capacity schemes that has led to lower levels of headroom capacity;
- **Facilitate economic growth:** The investments will support economic growth by enabling new connections and facilitating the expansion of housing, commercial and industrial activity. This requires new connections to be provided in a timely manner to support growth, along with sufficient supply of energy facilitated by robust planning of the network. This is essential for promoting sustainable development and protecting consumers while ensuring the electricity network can support Ireland's economic ambitions, with an expanded customer base including additional data centres.
- **Optimise existing capacity through innovation:** The investments provide an opportunity to deploy advanced grid management technologies and innovative solutions. This includes the use of flexibility services, energy storage, and smart grid technologies to enhance the efficiency and reliability of the electricity network. Embracing innovation can lead to more resilient and adaptable energy systems, capable of meeting future challenges.

To deliver PR6 successfully, the regulatory framework must be flexible enough to accommodate the proposed investments and provide mechanisms for adjusting allowances in response to changing conditions. Key considerations include:

- **Realistic allowances:** Allowances should be set to align with realistic delivery programmes that can be defined and monitored, and release additional funding as work progresses and is completed.
- **Adaptable Mechanisms:** Implementing mechanisms such as volume drivers and reopeners that allow for adjustments in allowances based on actual demand and generation levels. This flexibility ensures that investments can be scaled up or down as needed.
- **Performance Monitoring:** Establishing robust reporting and monitoring systems to track the progress and impact of the investments. This includes regular updates on project status, performance metrics, and impact assessments. Transparent reporting helps build trust among stakeholders and ensures accountability. Performance monitoring must be balanced with not being overly burdensome and allowing NCs to proceed quickly with required projects.
- **Stakeholder Involvement:** Engaging stakeholders in the regulatory process to ensure that their perspectives and concerns are considered. This includes regular consultations with network companies, policymakers, and consumers to gather feedback and make informed decisions.

8 Conclusion

The targets outlined in this report set out the scale of the challenge required to deliver net zero in line with accommodation of underlying demand, increasing numbers of connections, electrification of heat and transport, integration of additional RES. A significant step change in investment will be required by the NCs to address the challenge, whilst also augmenting the way that investment is planned and delivered.

A recent report by the UK NIC on 'Electricity distribution networks: Creating capacity for the future' [84] has provided the following conclusions that are pertinent for the situation in Ireland:

- *'We must learn the lessons of the UK's transmission infrastructure, where a failure to invest ahead of demand means we're playing catchup. Encouraging proactive investment requires a new system of managing, regulating and upgrading our distribution networks';*
- *'Distribution networks are how all homes and most businesses receive electricity. They are a vital component for successfully decarbonising the economy, so we need a concrete plan to ensure they are fit for the future'; and*
- *'Continuing a steady state approach will not be sufficient to meet future demand or deliver benefits, such as enabling economic growth and development'.*

The assessment presented in this report shows that the NC proposals demonstrate ambition to address the following high-level needs:

- **Provide capacity headroom:** Proposals to provide additional network capacity, overcoming existing constraints, are key to supporting the ambition to electrify heat and transport and accommodate additional volumes of intermittent renewable generation to contribute to decarbonisation. Additionally, it is necessary to address the historic underspend in network capacity schemes that has led to lower levels of headroom capacity;
- **Facilitate economic growth:** The investments will support economic growth by enabling new connections and facilitating the expansion of housing, commercial and industrial activity. This requires new connections to be provided in a timely manner to support growth, along with sufficient supply of energy facilitated by robust planning of the network. This is essential for promoting sustainable development and protecting consumers while ensuring the electricity network can support Ireland's economic ambitions, with an expanded customer base including additional data centres.
- **Optimise existing capacity through innovation:** The investments provide an opportunity to deploy advanced grid management technologies and innovative solutions. This includes the use of flexibility services, energy storage, and smart grid technologies to enhance the efficiency and reliability of the electricity network. Embracing innovation can lead to more resilient and adaptable energy systems, capable of meeting future challenges.

The proposed investments for PR6 face several key challenges:

- **Step-change in capex programme:** NCs are asking for a significant step-change in their allowances for PR6, compared to PR5- 131% and 347% for DSO and TSO & TAO, respectively.
- **Deliverability:** The significant step change in proposed expenditure raises concerns about the deliverability of the projects. Ensuring that the projects can be completed within the PR6 period requires careful planning and coordination.
- **Uncertainty:** The forecasted increases in demand and generation are subject to uncertainty, which can impact the accuracy of the investment proposals. This includes uncertainties related to economic growth, technological advancements, and policy changes.

To ensure the successful implementation of the proposed investments, we recommend the following is considered in setting the regulatory framework for PR6:

- **Realistic Allowances:** Set allowances that align with realistic delivery programmes, allowing for defined and monitored progress, and release additional funding as work progresses.
- **Adaptable Mechanisms:** Implement volume drivers and reopeners to adjust allowances based on actual demand and generation levels, ensuring investments can be scaled as needed.

- **Performance Monitoring:** Establish robust reporting and monitoring systems to track investment progress and impact, with regular updates on project status and performance metrics. Ensure transparency while avoiding overly burdensome requirements to allow NCs to proceed efficiently.
- **Stakeholder Involvement:** Engage stakeholders in the regulatory process through regular consultations with network companies, policymakers, and consumers to gather feedback and make informed decisions.

The findings of this Network Needs Assessment support the approach to acknowledge the level of uncertainty and need for substantial investment in providing determinations for PR6. However, there should be a strong focus within the regulatory framework on ensuring the required outputs are delivered, which will be supported by defining and monitoring specific delivery obligations associated with baseline allowances and mechanisms for providing access to additional funding through the regulatory framework within PR6.

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Appendices

Appendix A

Proposed asset volumes

A-1 Proposed asset volumes

The review of performance during PR5 reveals a mixed picture across different infrastructure categories. The following sub-sections present details of the forecast and outturn volumes of assets installed by the TAO and DSO in PR5, as well as the forecasts for PR6. The values are understood to be net additions to the system, taken from the PR6 BPQs, and cover overhead lines, underground cables, switchgear and transformers. In general, the outturn volumes of overhead lines and cables were lower than initially forecasted in PR5, whereas switchgear and transformers significantly exceeded the original projections, reflecting an approach to provide capacity at substations.

As we move into PR6, the electrical grid faces increasing demands driven mainly by the electrification of heating and transportation, and the integration of RES. Currently, 95 HV substations are fully utilised, highlighting the urgent need for mitigation strategies to address capacity constraints and the aging assets within the network.

It should be noted that the net additions to the system correspond to load related expenditure, driven by the increases in demand and connection volumes. In isolation, the analysis (based on available data) does not support the need for “catch up” investment being required in PR6. Overall, the load related expenditure forecast appears to be consistent with meeting the forecast in new connections, demand and generation whilst maintaining compliance with network security standards.

A-1-1 TAO Asset Investments

The total reported asset volume additions associated with investments in PR5 and PR6 are illustrated in Figure A-1.

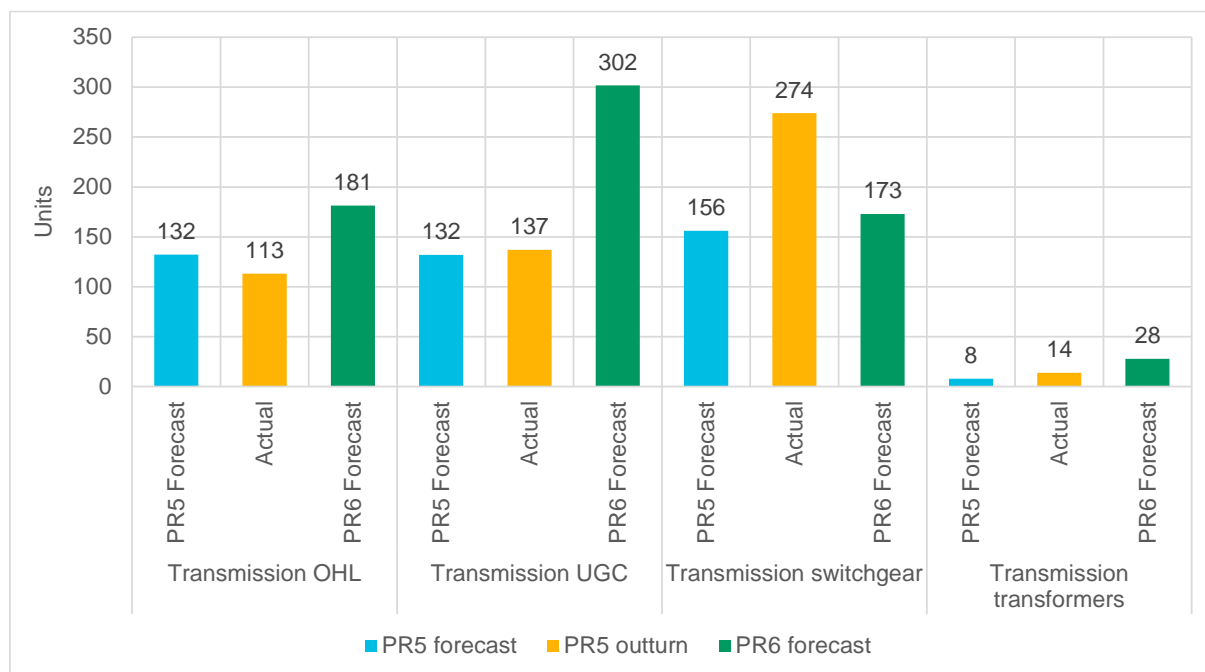


Figure A-1 Comparison of TAO asset volumes PR5-6

Details about the individual

Overhead Lines

During PR5, the proposed investments in overhead lines (OHL) were ambitious, with a forecasted cumulative investment reaching 133 km. However, the actual investments fell short of these projections, achieving a cumulative total of 113 km by 2024. This difference highlights the potential challenges faced in executing the planned enhancements.

Looking ahead to PR6, the proposed investments are modest during the first half of the 5-year period, with a substantial volume forecast to be added in 2027, as shown in Figure A- 2. The total forecast volume is set to reach 181 km by 2030 (60% increase over PR5 outturn), corresponding to efforts to address existing constraints.

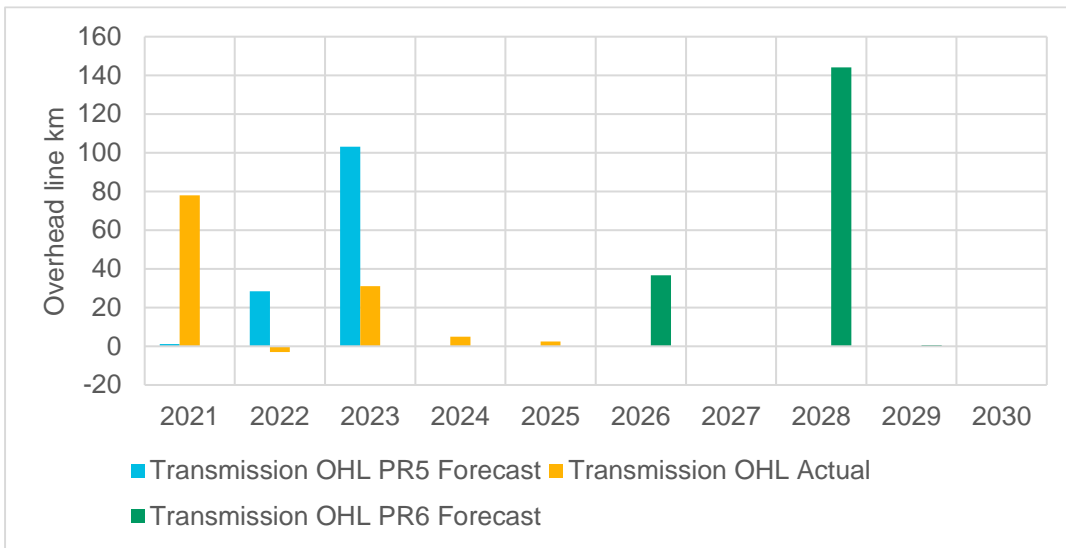


Figure A- 2 TAO Overhead lines: actual and planned investments

Underground Cables

In PR5, the forecast investments in underground cables (UGC) aimed to install a total of 132 km. Notably, the actual investments surpassed these expectations, reaching 137 km in 2025. Several factors may have contributed to exceeding the initial targets, such as certain projects requiring adjustments or expansions beyond the initial scope, leading to the increased investment.

For PR6, the investment strategy shows a phased approach, with substantial volumes projected to be added in 2028 and 2029, as shown in Figure A- 3. The total forecast is set to reach 302 km by 2030 (120% increase over PR5 outturn), highlighting a strong focus on developing the network to address existing constraints.

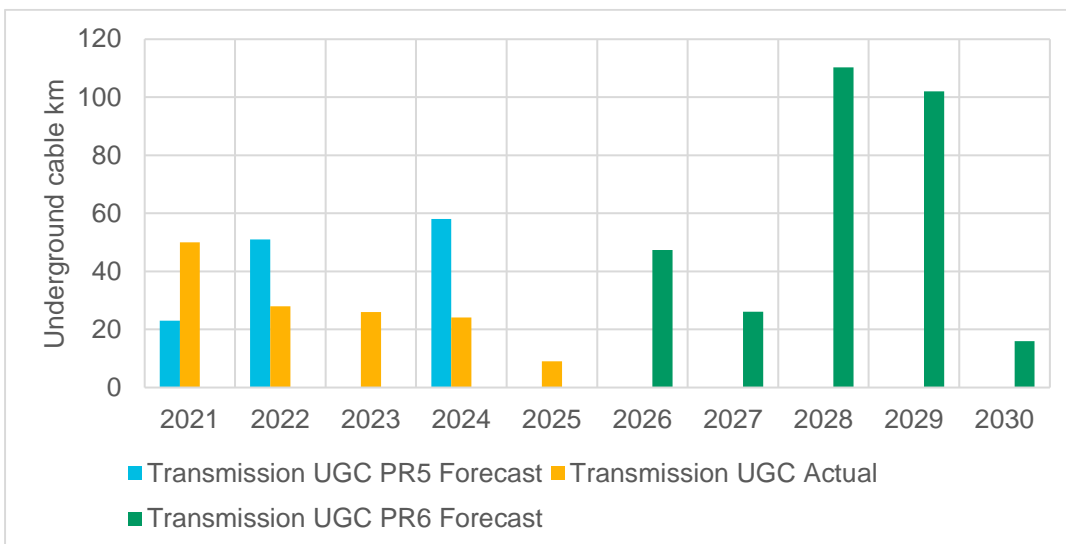


Figure A- 3 TAO Underground cables: actual and planned investments

Transformers

In PR5, the forecast investment in transformers was relatively modest, with a total of 8 units planned to be added. However, the actual investments exceeded this projection, reaching a total of 14 to be completed by the end of PR5. The increased investment in PR5 likely reflects the need to replace aging transformers, accommodate growing demand, and integrate renewable energy sources more effectively.

Looking ahead to PR6, the investment plan shows a significant ramp-up starting from 2026, with a total of 28 transformers to be added and/or replaced by 2030 (100% increase over PR5 outturn). The annual transformer installations over PR5 and PR6 are presented in Figure A- 4.

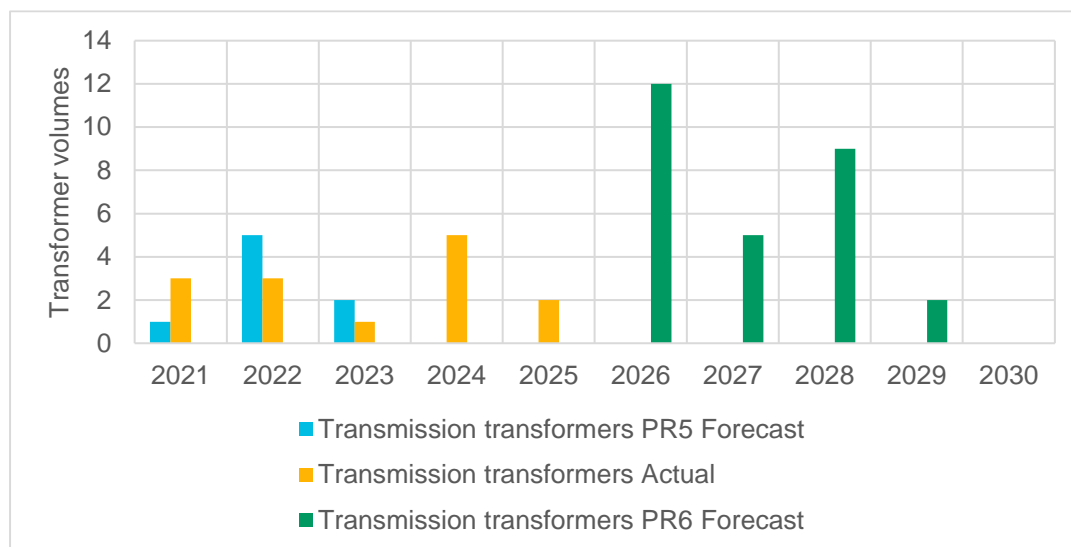


Figure A- 4 TAO Transformers: actual and planned investments

Switchgear

During PR5, the forecasted investments in switchgear⁹ were set to reach a cumulative total of 156 units by 2025. However, the actual investments significantly exceeded these projections, achieving a cumulative total of 261 units in 2024. This substantial overachievement suggests a strategic prioritisation of switchgear enhancements, reflecting the need to modernise and expand the switchgear infrastructure to enhance system reliability and safety.

The proposed investment plan for PR6, aims to add a total of 173 switchgear units by 2030 (34% decrease compared with PR5 outturn). The annual forecast and actual switchgear installations over PR5 and PR6 are presented in Figure A- 5.

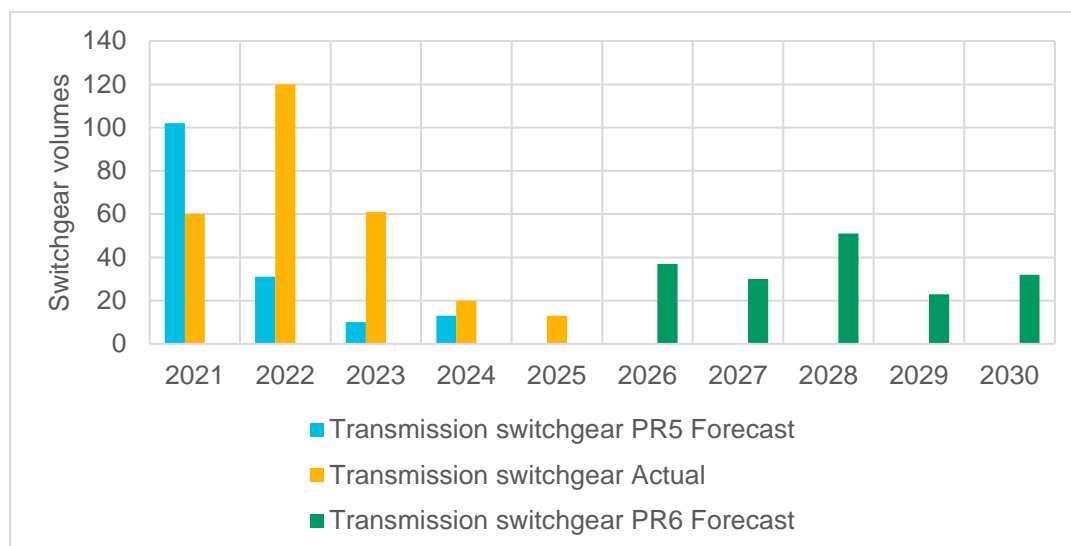


Figure A- 5 TAO Switchgear: actual and planned investments

⁹ The volumes of switchgear are presented for completeness. However, it is anticipated that these are principally non-load related interventions and of limited relevance to the assessment of requirements for the Low Carbon energy system.

A-1-2 DSO Asset Investments

The total reported asset volume additions associated with investments in PR5 and PR6 are illustrated in Figure A-6.

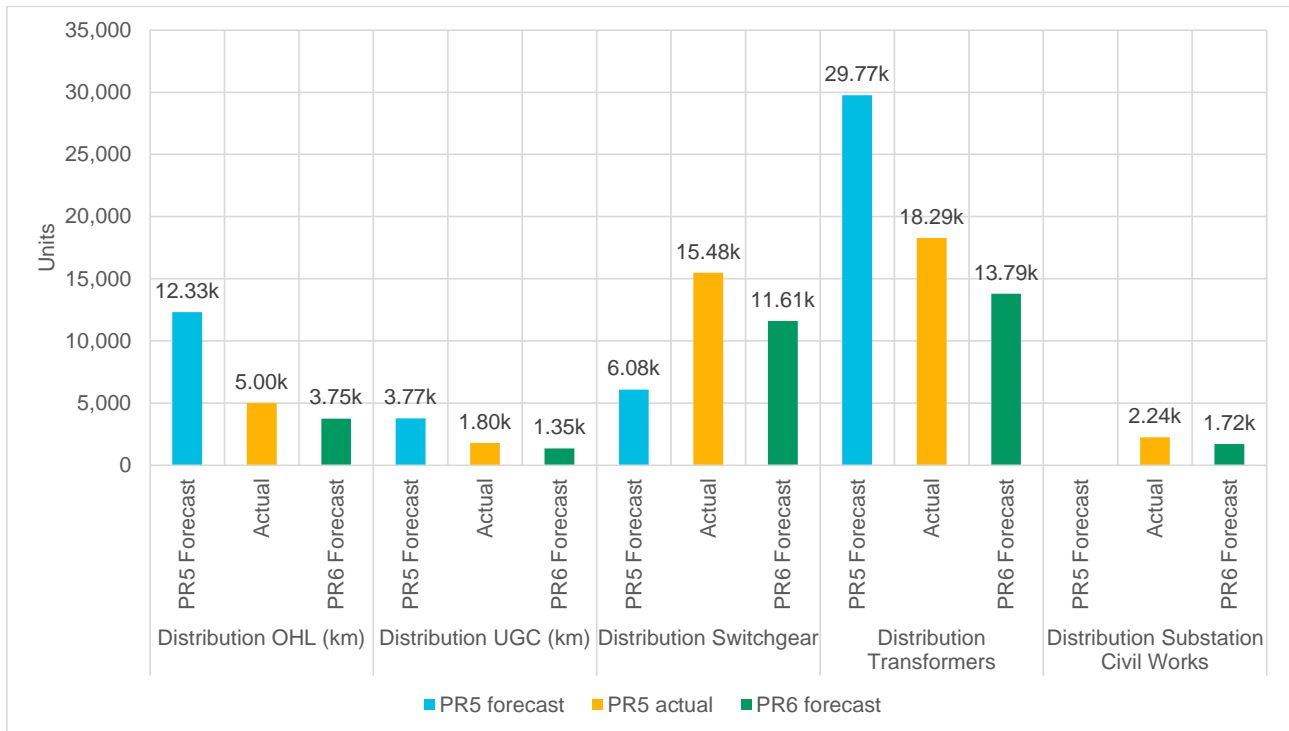


Figure A-6 Comparison of DSO asset volumes PR5-6

Overhead Lines

The forecasted investments in overhead lines for the PR5 period were ambitious, aiming for a cumulative total of 12,326 km by 2025. However, the actual investments fell short, reaching less than a half of the anticipated additions at a cumulative total of 5,004 km by the end of 2025. Several factors could have contributed to this shortfall, including logistical challenges, regulatory hurdles, or unforeseen technical issues.

As shown in Figure A-7, the investment strategy for overhead lines during PR6 is more conservative, with a total forecast of 3,753 km (25% decrease compared with PR5 outturn). This moderate approach likely reflects a realistic assessment of the resources and time required to implement these projects effectively (particular challenges related to progression of overhead line projects), based on the actual data and experience from PR5.

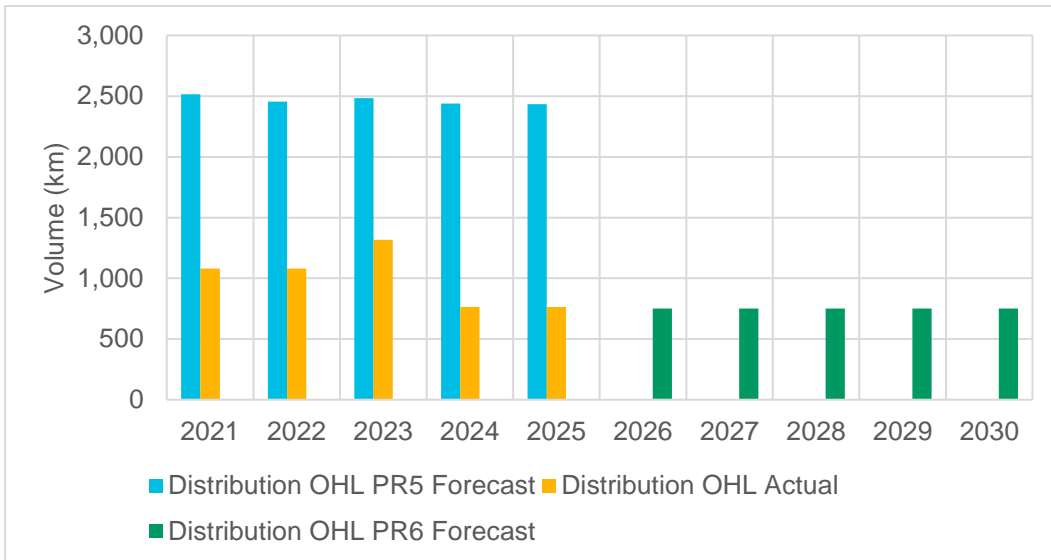


Figure A-7 DSO Overhead lines: actual and planned investments

Underground Cables

A similar outcome was observed for underground cables during PR5. The forecast investments corresponded to a total of 3,775 km by 2025. However, the actual investments reached only 1,799 km. This significant discrepancy suggests that various challenges impacted the execution of the planned investments, resulting in not all anticipated work being conducted.

Looking ahead to PR6, the investment plans suggest the expansion of the underground distribution network by 1,349 km by 2030 (reduction of 25% compared with PR5 outturn). The annual forecast and actual length of underground cable installations over PR5 and PR6 are presented in Figure A- 8.

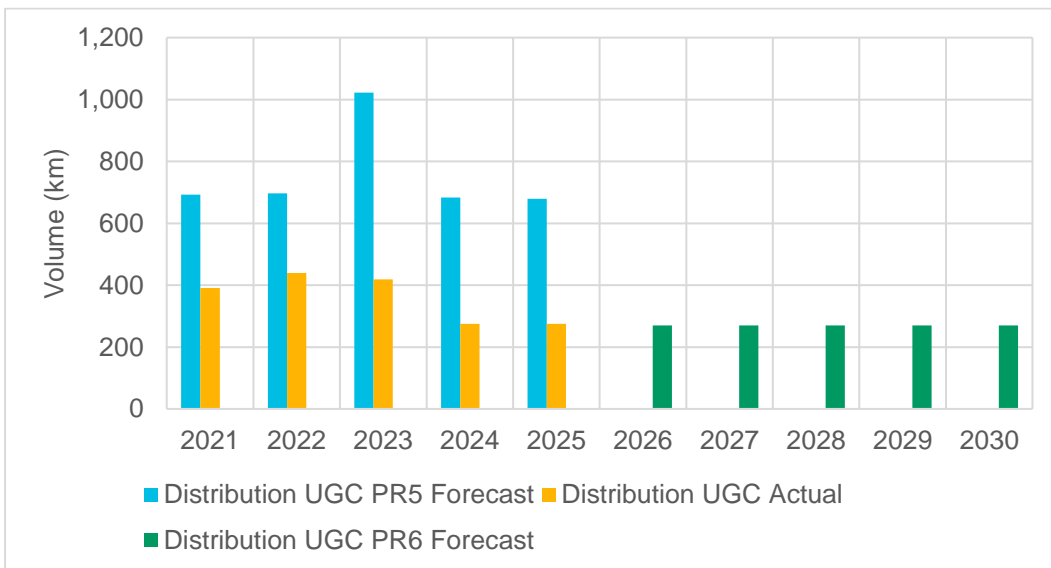


Figure A- 8 DSO Underground cables: actual and planned investments

Transformers

In PR5, the anticipated investments in transformers were set to reach a total of 29,766 by 2025. However, the actual investments were significantly lower, culminating in a cumulative total of 18,285 by 2025. This notable shortfall indicates that various challenges may have hindered the execution of the planned investments.

Looking ahead to PR6, the investment strategy for transformers shows a phased approach, with a total forecast reaching 13,789 by 2030 (25% reduction compared with PR5 outturn). This planned investment trajectory suggests a more measured and realistic assessment of the resources and time required to implement these

projects effectively, informed by the experiences of PR5. The total forecast and actual transformer installations over PR5 and PR6 are presented in Figure A- 9.

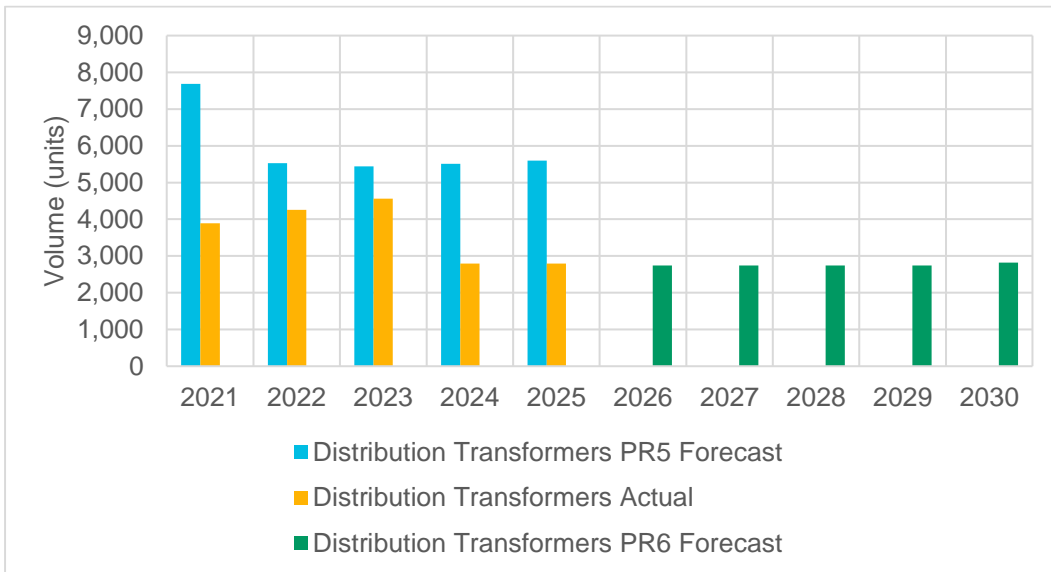


Figure A- 9 DSO Transformers: actual and planned investments

Switchgear

In PR5, the projected investments in switchgear were set to reach a total of 6,084 units by 2025. The actual investments far exceeded these projections, with a total of 15,480 units in in the period. These substantial investments in PR5 likely reflect an urgent need to upgrade outdated equipment, address capacity constraints, and integrate advanced technologies to improve grid resilience.

Looking forward to PR6, the investment strategy for switchgear is set to continue this momentum, with a cumulative forecast reaching 11,610 by 2030 (25% reduction compared with PR5 outturn). The annual forecast and actual switchgear installations over PR5 and PR6 are presented in Figure A1- 1.

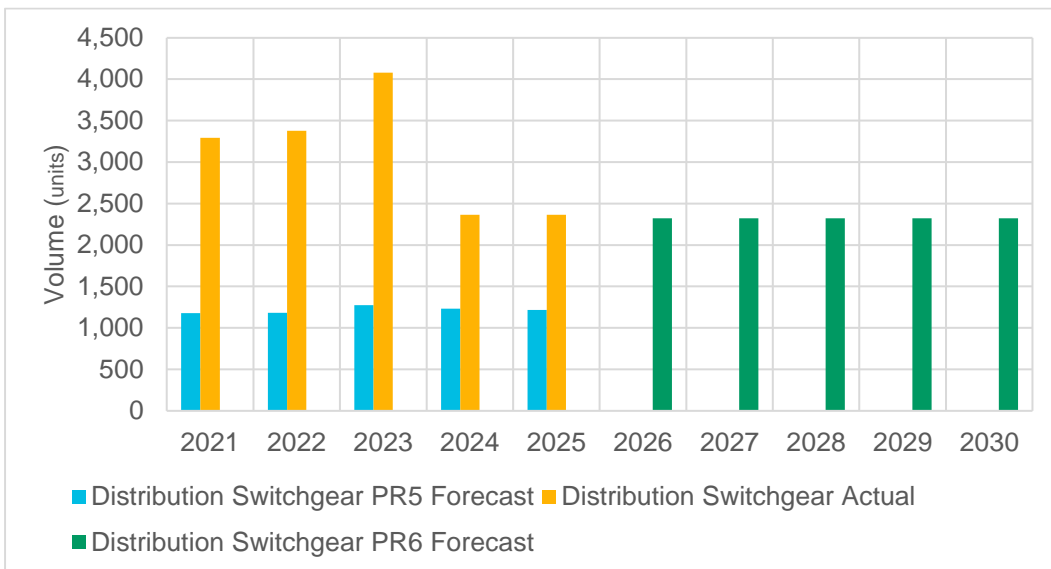


Figure A1- 1 DSO Switchgear: actual and planned investments

Substation Civil Works

Details of the forecast volumes associated with investments in PR5 for substation civil works are not available. However, actual investments were made relating to a total of 2,243 sites by 2025.

For the PR6 period, a forecast of 1,720 sites are proposed for substation civil works (23% reduction compared with PR5 outturn). The annual forecast and actual substation civil works over PR5 and PR6 are presented in Figure A-10.

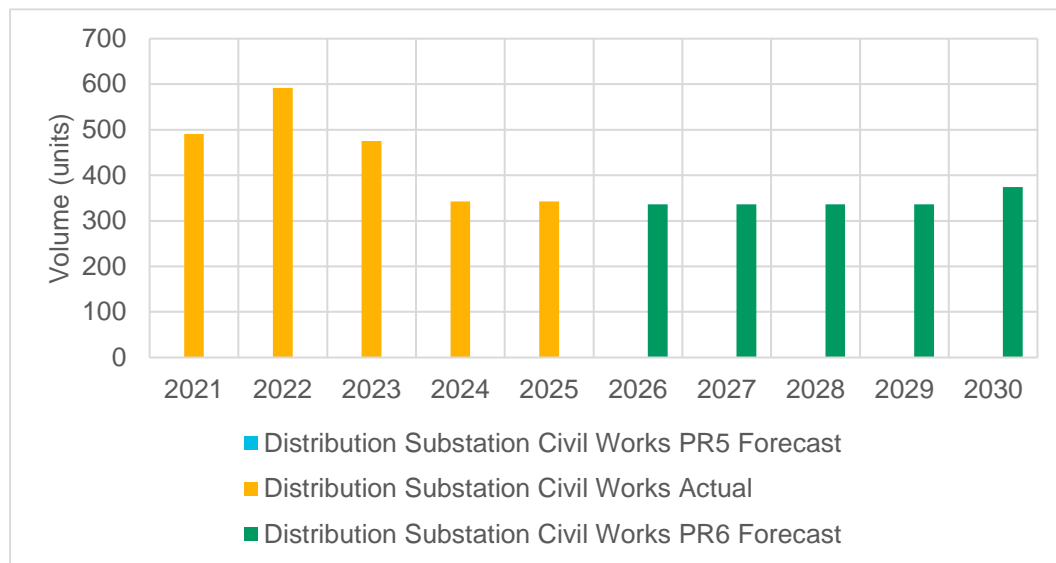


Figure A- 10 DSO Substation civil works: actual and planned investments



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