Powering Ireland's Energy Future

Approaches for a secure, renewables-led electricity system to 2035

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Abstract

Ireland has emerged as a frontrunner in integrating wind power, which supplied around a third of its electricity in 2024. As this power system transformation continues, electricity is set to be the backbone for achieving Ireland’s climate, energy and socio-economic ambitions, making electricity security critical to realising progress in key areas including housing, digital infrastructure, transport and heat. Going forward, Ireland faces strategic choices on how to align its ambitions while ensuring secure electricity supply to 2035.

This report assesses the outlook for Ireland’s energy security to 2035, drawing on international experience and detailed power system modelling developed with EirGrid, Ireland’s transmission system operator. The Adapted Transition Pathway illustrates how climate, energy and socio-economic goals align around the electricity system, potentially doubling demand and requiring faster infrastructure delivery and deployment of renewables. We find that there is a clear need to establish a unified cross-sectoral energy strategy to set a vision that guides this transition, supported by a detailed security study on the electricity supply mix.

The analysis sets out five pillars for policy action: Establishing a cross-sectoral energy security strategy for the 2030s; delivering the enabling infrastructure to accommodate the growth of electricity demand and supply; accelerating the delivery of generation capacity, storage and demand-side flexibility; enabling secure system operation under high renewable penetration; advancing workforce skills, strengthening partnerships and facilitating electrification. Ireland can build on its progress in power system transformation to set an example of secure integration of large shares of variable renewable generation while safeguarding energy security.

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Executive summary

Ireland faces strategic choices to align its energy, climate and socio-economic goals through 2035

Over the next decade, decision makers in Ireland will need to balance a range of trends and policy ambitions that have strong implications for the power sector. Ireland has set a range of policy goals spanning the next decade, from improving energy security by reducing its reliance on imported fossil fuels, to meeting its climate targets, expanding its housing stock, and supporting the growth of digital infrastructure such as data centres. These ambitions all have strong links to the country's power sector, with implications for electricity demand, infrastructure and supply. In this context, it will be key for Ireland to consolidate its wider strategic vision and integrate it with longer-term power system planning. This will help set priorities and guide market and system development, while allowing potential trade-offs to be proactively identified and managed, where possible.

Ireland has a long track record of transforming its power system while managing strong electricity demand growth. In 2024, Ireland supplied about one-third of its electricity from wind, four times the global average and second only to Denmark among countries with gigawatt-scale systems. That made wind the second largest source of electricity in Ireland behind natural gas, which had a share of more than 40%. This achievement – the result of pioneering initiatives to integrate renewables – is outstanding for a relatively small, island-based grid, and it was managed as annual electricity demand grew by about 20% between 2015 and 2023. Ireland is scaling infrastructure and modernising operations further to reach its goals of 80% renewable electricity by 2030 and running a system almost entirely from wind, solar, storage and imports by 2035, while managing growing electricity demand from the housing, data centre, heat and transport sectors.

To support decision makers as they plan for the future, this report introduces a pathway that explores what would be required to maintain electricity security while advancing towards Ireland's ambitions. This Adapted Transition Pathway was developed with EirGrid, which manages Ireland's transmission grid. It combines a range of existing projections and scenarios based on Ireland's sectoral ambitions, exploring how the supply side could transform to meet a potential near doubling of electricity demand by 2035, driven by growth in the housing and data centre sectors and efforts to accelerate the electrification of heat and transport. This pathway illustrates how various ambitions align around the power sector, while highlighting the potential trade-offs that may need to be managed between energy security, decarbonisation and affordability.

Ireland's power system must evolve across demand, supply and operations to meet policy ambitions

The properly managed electrification of heating and transport would sharply reduce Ireland's reliance on imported fossil fuels. Replacing oil- and gas-based boilers and vehicles with electric alternatives could cut direct fossil fuel imports by 38% and lower annual import bills by EUR 2.8 billion. This would support significant reductions in Ireland's reliance on imported fossil fuels, which currently account for 80% of total national energy supply. However, significant upfront costs, high electricity prices compared with fossil fuels, and grid capacity constraints remain barriers. Integrating heat electrification with thermal storage and incentivising smart charging will be essential to align new demand with renewable generation and reduce strains on the power system.

Meeting rising electricity demand in the Adapted Transition Pathway would require faster deployment of renewables. This pathway sees electricity demand nearly doubling to 2035. From 2023, electricity demand from the residential and data centre sectors would each grow by about 7 terawatt-hours (TWh) to 2035. However, without faster progress, the 80% renewables target for 2030 would not be met, increasing dependency on electricity imports and prolonging reliance on natural gas-fired generation, which set wholesale electricity prices 80% of the time in 2022 and currently accounts for 60% of national natural gas consumption.

Higher renewable penetration would shift the role of thermal generation to a security backup. In the Adapted Transition Pathway, gas-fired plants would continue to play a role in maintaining electricity security, though they shift from delivering the bulk of electricity supply to providing flexibility and helping to meet peak demand, including during periods of low renewable output. This would result in the utilisation rate (or capacity factor) of gas-fired plants falling from about 46% in 2023 to 12% in 2035. This lower utilisation would make it less economically viable to keep all units available, since operators would need to cover fixed costs despite more limited running hours. While gas-fired generation would continue to support electricity security, ongoing reliance on imported natural gas would continue to expose the power system to potential supply disruptions and the volatility of fossil fuel markets. To manage this trade-off, Ireland will need financing mechanisms that can help guarantee that there is sufficient thermal capacity to ensure electricity security, but investments do not exceed what is needed.

Ireland should strategically assess and choose the composition of its electricity supply portfolio, with potential demand trajectories in mind. In the Adapted Transition Pathway, Ireland would reach a peak residual demand, or a measure of total demand minus wind and solar output, of 10 gigawatts (GW) by 2035. To cover this demand securely under that pathway, Ireland would need to develop a portfolio that reaches 16 GW of dispatchable capacity (including thermal generation, storage and interconnectors). This would require ambitious development of new battery capacity and higher electricity imports, alongside thermal plants that would operate mainly as backup power supply. Depending on how demand and the supply mix evolve under different policy pathways, revising capacity requirements often will be crucial for prudent planning, along with continued efforts to reduce reliance on imported fossil fuels.

Delivering on demand and supply ambitions while strengthening resilience depends on timely grid investment. In the Adapted Transition Pathway, transmission and distribution grids must manage rapid demand growth from households, data centres, heat and transport, while also integrating more renewables. Ireland is ramping up grid investments, planning on a record EUR 10-14 billion between 2026 and 2030, up from EUR 5 billion between 2021 and 2025. But long lead times and permitting challenges remain key barriers. Grid investments should include a focus on resilience, particularly in rural areas, which suffered the longest outages due to Storm Éowyn in 2025. Additionally, new cross-border interconnectors, on top of those already planned, should be considered to further diversify supply.

Operating a system dominated by wind and solar, batteries and interconnectors will require new approaches to stability and flexibility. In the Adapted Transition Pathway, renewables would supply 88% of electricity by 2035, supported by expansion of energy storage and interconnectors. Converter-connected technologies – including wind, solar and batteries – would transform how the system operates, and which resources deliver essential power system services. By 2035, inertia, ramping and other services in the Adapted Transition Pathway would be provided mainly by batteries, demand response and synchronous condensers at levels not yet observed internationally. This highlights the need for further studies and continued modernisation of system operations to ensure system security.

A cross-sectoral energy security strategy for the 2030s should guide the next phase of Ireland's transition

To deliver on Ireland's energy, climate and socio-economic goals, including the decarbonisation of its power sector while maintaining electricity security and affordability, this report makes a series of recommendations. These include:

Establish a cross-sectoral energy security strategy for the 2030s. The Adapted Transition Pathway illustrates how ambitious goals across housing, data centres, transport and heat converge around the power sector, driving rapid growth in electricity demand. Ireland would benefit from an integrated strategy to align these efforts with its decarbonisation and energy security objectives. A unified strategy would consolidate sectoral ambitions, assess trade-offs, and set clear priorities and milestones for developing power system infrastructure, markets and operations. It would also allow for an infrastructure needs assessment conducted in tandem with an in-depth study of power system adequacy to evaluate electricity security under the envisioned pathway.

Accelerate the delivery of grid infrastructure alongside additional electricity supply and flexibility resources. The Adapted Transition Pathway highlights the scale of new infrastructure needed to deliver on multiple ambitions, which would result in both high demand growth and renewable penetration in power supply. Major investment plans are in place, yet the challenge will be ensuring timely delivery given long lead times. Anticipatory and flexible investment must be complemented by faster permitting, proactive supply chain management, as well as incentives and connection requirements for higher demand flexibility to ensure grids, generation and flexibility resources are ready when needed.

Enable secure operations under high renewable penetration. As the power system evolves and flexible demand comes online, Ireland should translate the technical requirements for ensuring stability and flexibility into concrete policy and operational measures. This entails building on EirGrid's groundwork with SONI, Northern Ireland's electricity transmission system operator, upgrading operational frameworks, investing in advanced modelling and automation, and continuing to update grid codes and system services arrangements. Strengthened cybersecurity and close collaboration among operators, regulators and policymakers is needed to ensure that Ireland's operational capabilities evolve fast enough to safeguard security as the share of renewable electricity evolves.

Advance workforce skills, strengthen partnerships and facilitate electrification. These areas will be key to the success of Ireland's policy goals. Training and reskilling programmes and knowledge sharing would prepare institutions to manage a more complex power system. Meanwhile, stronger regional and global partnerships will boost innovation, accelerate infrastructure delivery, and strengthen key supply chains to procure technology, infrastructure and energy commodities. At the same time, tackling barriers to the electrification of heat and transport – such as by addressing cost gaps by considering tariff reforms and instituting targeted policies to overcome infrastructure constraints – would speed up Ireland's transition while maintaining energy security.

With a clear vision and co-ordinated action, Ireland can continue to be a global example for managing secure energy transitions. Building on its success in wind integration and system innovation, Ireland can show how a relatively small, island-based system can operate securely with very high shares of renewables. By doing so, it can continue to advance its own socio-economic and climate goals while offering lessons for other countries pursuing ambitious transitions.

Introduction

A secure power system is essential for the effectiveness of socio-economic, climate and energy strategies to 2035

In addition to being the backbone of Ireland's national decarbonisation goals, the electricity system is a strategic enabler for broad policy objectives that combine decarbonisation, economic growth, housing development, and wider energy security[1] and affordability. As electricity demand from data centres, homes, and the heat and transport sectors continues to grow, Ireland's ability to enhance its electricity security will increasingly determine the achievement of its socio-economic, climate and development goals.

Electricity security is thus not only a technical issue, but a foundational strategic one that requires careful forward-looking planning and co-ordination across multiple policy areas. Decisions need to be made now to secure infrastructure that will take years to develop, and to provide clarity for investors and stakeholders.

Ireland plans to continue striving to meet its ambitious decarbonisation goals as it advances several policy priorities simultaneously, including economic growth, housing development, and broader energy security and affordability. As a relatively small, island-based system (operated in close co-ordination with Northern Ireland), Ireland stands out as a frontrunner in wind power integration, supplying a remarkable 40% of its electricity from renewables in 2024, with wind alone contributing about 32%. Building on this strong foundation, the country aims to supply 80% of its electricity from renewables by 2030, and to have its power system running almost exclusively on renewables by 2035, supported by interconnections, storage and dispatchable generation.

However, the country is facing key strategic decisions as it moves into the next phase of its energy transition, and effective policies and regulations will be the key to success. Questions include: What is the role of the power sector in enhancing decarbonisation and energy security in Ireland? What could be the adequacy, stability and flexibility challenges in the Irish power system towards 2035? Which cross-sectoral considerations are relevant to ensure energy security? What are the key policy areas where action is needed? Making these difficult decisions will require careful consideration to understand interactions within and among all areas.

[1] The IEA defines energy security as the uninterrupted availability of energy sources at an affordable price.

Our analysis takes place at a strategically important time for Ireland, as electricity demand is expected to grow rapidly due to rising electricity use by residential and industry sector development, data centres (which already account for 22% of annual consumption) and electrification of end uses. This situation provides Ireland with a key opportunity to improve its energy security by reducing reliance on imported fossil fuels, which account for 80% of its total energy supply.

Considering these challenges and opportunities, this report provides an independent assessment of Ireland's electricity security during its energy system transition through 2035, offering the government policy options to evaluate based on costs and benefits. This report draws on power system modelling and builds on previous work such as the IEA Ireland 2024 Energy Policy Review and the Irish government's Energy Security in Ireland to 2030 strategy and Independent Review – Security of Electricity Supply.

This study identifies key risks and priorities in the central areas of flexibility, resource adequacy, operational security and resilience. Furthermore, this report addresses the overarching energy security considerations of fossil fuel import reliance and the role of electrification, emphasising how a secure power system can enhance energy security and decarbonisation.

Thus, the five chapters of this report assess Ireland's energy security and offer policy recommendations to enhance it:

- **Chapter 1** examines five reasons for a focused assessment of Ireland's energy security to 2035, and it recognises the key power sector elements and trends that are important for evaluating energy security in an electricity sector context.
- **Chapter 2** explores how ambitious heat and road transport electrification could reinforce energy security and decarbonisation, but it also identifies key barriers such as low cost-competitiveness with fossil fuel-based alternatives, as well as grid infrastructure constraints.
- **Chapter 3** depicts the Irish power system in 2030 and 2035. It presents the Adapted Transition Pathway scenario, adapted in collaboration with Ireland's transmission system operator EirGrid, investigating trends, risks and trade-offs involved in realising ambitious electrification and decarbonisation outcomes while observing planned electricity system security limits.
- **Chapter 4** addresses future challenges in maintaining operational security and resilience, leveraging Adapted Transition Pathway scenario results and taking stock of ongoing work in Ireland to overcome these hurdles.
- **Chapter 5** offers policy recommendations to enhance energy security in Ireland through an integrated framework based on five pillars: establishing a cross-sectoral energy security strategy for the 2030s; developing enabling infrastructure; expanding generation capacity, storage and demand-side flexibility; enabling secure operation under high renewable penetration; and advancing workforce skills, strengthening partnerships and facilitating electrification.

Chapter 1. Context

Ireland has emerged as a world leader in wind power integration, using wind to supply about 32% of its electricity (including imports) in 2024 – second only to Denmark among large power systems globally. Recognising that power system reliability is essential for economic and social wellbeing as the country works towards its ambitious target of 80% renewable electricity by 2030, it will be critical to ensure electricity security to serve multiple national priorities: higher energy independence; decarbonisation; industrial competitiveness; housing expansion; and consumer affordability. With the share of electricity in total final energy consumption at roughly 25% in 2023 and expected to rise as electrification expands, data centres proliferate and the population grows, managing this transformation securely will be essential to enable progress in all government priorities while advancing renewable energy deployment.

Thus, electricity security strategies that balance all government objectives will be required to successfully manage Ireland's power system transformation to 2035. While traditional electricity security frameworks rely primarily on technical reliability indicators, what is now needed is a broader approach that addresses imported fossil fuel dependence, structural demand changes, the diverse needs of households and industry, and economic development. A broader security framework will be particularly important during 2030-2035, when Ireland aims to transition from rapid renewable energy deployment to operating a predominantly renewable energy-based electricity system while ensuring affordability and reliability for all sectors.

In examining Ireland's electricity security context, this chapter provides an overview of the current power system, the institutional landscape and key trends shaping the path to 2035. Our analysis covers critical security dimensions such as affordability, industrial strategy requirements, interconnection development, grid infrastructure and system reliability.

Rationale for this energy security assessment

This section explores the key reasons for studying Ireland's energy security outlook to 2035. They emphasise the potential need for trade-offs among several of Ireland's energy objectives, including scaling up renewable energy production rapidly; meeting rising power demand from various sources such as data centres and from population growth; and ensuring that energy remains affordable and secure. The country may need to prioritise some objectives over others in certain cases. As electricity demand grows, and as system complexity increases and delivery risks become more acute, critical trade-offs among policy, investment and market design choices will become more apparent. Decisions made today will determine who benefits and who bears the costs later, especially if not all objectives can be fully achieved simultaneously.

Power sector targets are central to Ireland's economic development, and delays could reinforce natural gas reliance

While Ireland's power sector targets are central to its climate goals, they are also foundational to the country's broader economic ambitions. Expanding clean electricity production is essential to reduce reliance on imported fuels, enable electrification, attract investment and support population growth. Delivery delays could boost reliance on natural gas, increase exposure to international fuel market volatility and slow progress on decarbonisation. The pace at which these targets are met will affect the delicate balance between energy security and affordability – and Ireland's ability to develop sustainably.

With the 2021 Climate Action and Low Carbon Development Act signed into law, Ireland is legally committed to net zero emissions no later than 2050, and to 51% less emissions than in 2018 by 2030. This framework rests on a series of five-year carbon budgets starting in 2021, complemented by sectoral emission ceilings (SECs) for each budget period. The sectoral ceilings require energy-related greenhouse gas emissions to decline rapidly, especially in the power sector, which has an indicative target of ~75% emissions reduction by 2030 compared to 2018 levels.[2]

Ireland's annually updated Climate Action Plan defines actions and measures for each sector to comply with carbon budgets and SECs. Accordingly, the current plan targets the power sector, aiming to raise the share of electricity demand met by renewables to 80% by 2030 from 40% in 2024, with ambitious capacity targets of 9 GW for onshore wind, at least 5 GW for offshore wind, and 8 GW for solar PV. To help the power system operate smoothly with high shares of variable renewables, the government has also set targets to increase demand-side flexibility from 5% in 2024 to 20-30% in 2030, and to procure at least 2 GW of flexible gas generators by 2030.

[2] To meet the targets, steep declines must also be achieved in transport (~50%), residential and commercial buildings (40-45%) and industry (~35%) by 2030.

Ireland power sector targets and status, 2024 and 2030

Indicators	Status as of 2024	Targets for 2030
Renewable share in electricity demand	40%	80%
Onshore wind capacity	5.1 GW	9 GW
Offshore wind capacity	0.03 GW	At least 5 GW
Solar PV capacity • *Of which microgeneration of ≤ 50 kW*	1.2 GW *0.5 GW*	8 GW *1.6 GW*
Demand flexibility	5%	20-30%
Flexible gas-fired generation	N/A	At least 2 GW addition

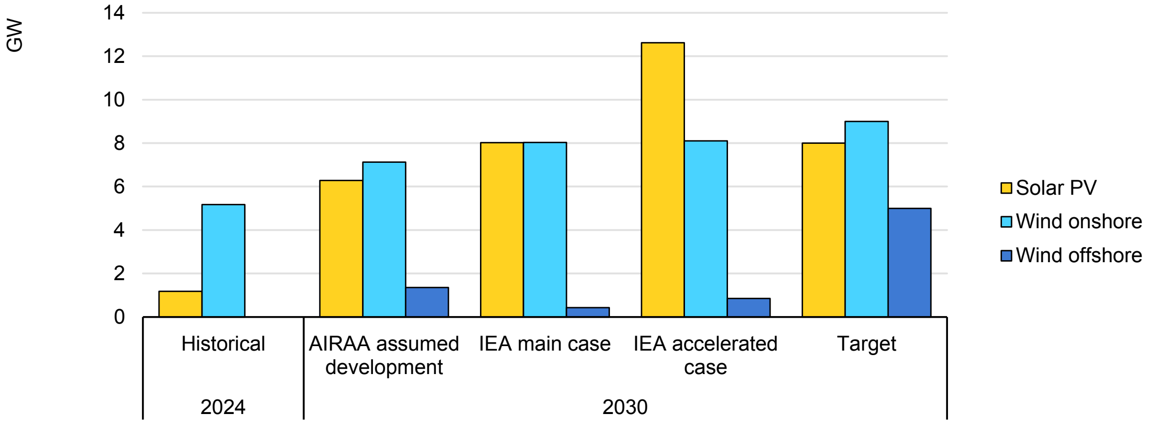
Note: Demand flexibility is measured as a percentage of average daily demand.
Sources: Climate Change Advisory Council (2025), Annual Review 2025: Electricity; Commission for Regulation of Utilities (2024), National Energy Demand Strategy.

As Ireland's energy system electrifies and decarbonises, delays in renewable capacity buildouts and grid expansion could mean that gas-fired generation would need to be used to meet a larger share of electricity demand – not just provide flexibility and system services. In Ireland's relatively small power system, which has total peak electricity demand of 5-6 GW, the shortfall in planned offshore wind capacity is a substantial gap relative to the system's size. The SEAI and previous IEA analyses have projected less than 1.4 GW by 2030, compared to the 5-GW target.

This could increase reliance on natural gas and electricity imports, heightening exposure to supply disruptions and wholesale price volatility during periods of tight market conditions. A larger role for gas-fired generation would also affect emissions trajectories and the system's resilience to fuel price shocks, as illustrated by the recent European energy crisis. Additionally, delayed renewable energy deployment and grid reinforcement could reduce operational flexibility and limit the system's ability to accommodate demand growth and electrification, particularly in Dublin where capacity growth is forecast to lag behind demand into the 2030s.

To unlock Ireland's full power system transformation potential, offshore wind development will need to be scaled up by strengthening capabilities across domestic supply chains, building out port infrastructure and establishing a specialised workforce. Additionally, the government has highlighted the need to increase staffing in regulatory and planning authorities and to streamline planning and permitting processes to enable timely project delivery.

Historical and projected wind and solar PV generation capacity in the All-Island Resource Adequacy Assessment, IEA scenarios, and national targets in 2024 and 2030



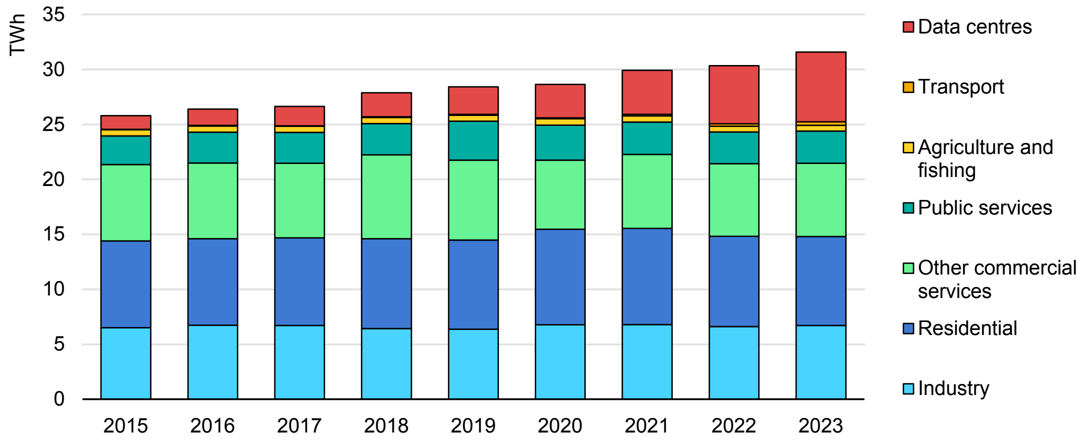
Notes: AIRAA is All-Island Resource Adequacy Assessment, IEA main and accelerated case are from Renewables 2024.
Sources: IEA (2024), Renewables 2024; EirGrid, (2024), All-Island Resource Adequacy Assessment 2026-2035: Inputs & Assumptions for Ireland; Government of Ireland (2024), Climate Action Plan 2024.

Data centres, housing buildouts and electrification trends are driving rapid power demand growth

Ireland's electricity consumption growth has well exceeded EU averages, primarily because of its commercial service sector. In 2015-2023, EU electricity consumption fell 5%, led by a 11% drop in industrial demand, whereas Irish electricity demand rose roughly 22% (from 26 TWh to 32 TWh), driven mainly by strong growth (+50%) in service sector demand. Data centres were responsible for much of this increase, as Ireland's strong digital infrastructure and subsea connections to major markets, among other factors, have contributed to sustained data-centre investment. In fact, data centres accounted for 6.9 TWh (22%) of Ireland's total electricity consumption in 2024, up from just 5% in 2015.

In contrast to service sector demand, residential consumption has grown more modestly. Despite expanding end-use electrification, residential power demand rose almost 3% between 2015 and 2023. In 2023, a significant jump in electricity prices influenced a 4% drop in residential electricity use, while home energy efficiency improvements supported a decline in space heating demand of 45% per square metre between 2000 and 2022. Furthermore, in the past three years, heating degree days (HDDs) have been below the long-term average (2000-present), further limiting heating-related demand. However, residential demand growth is expected to increase as Ireland's population expands from 5.3 million to a projected 6 million by 2030 and more energy uses become electrified.

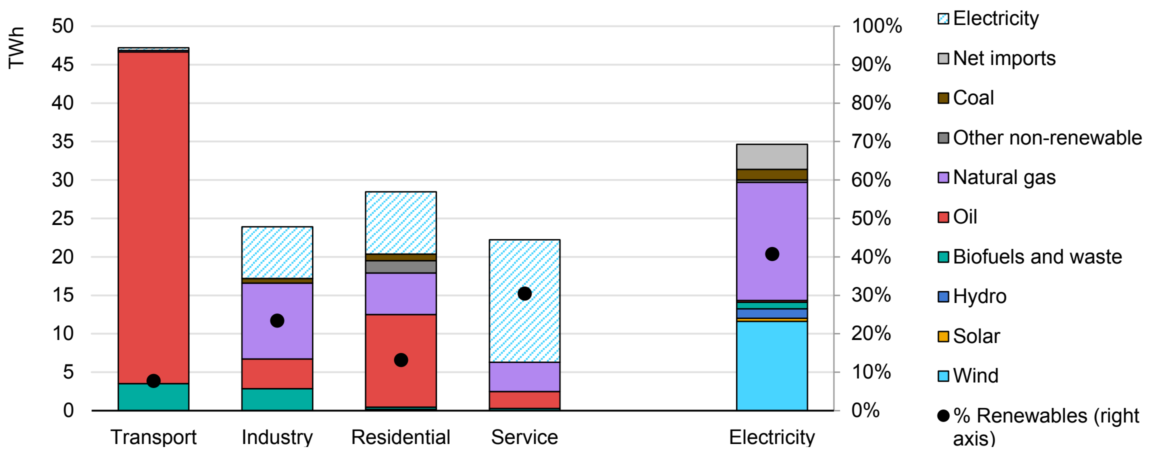
Electricity demand by sector in Ireland, 2015-2023



Source: IEA analysis based on SEAI (2024), Energy In Ireland.

Electricity demand in industry and transport has also grown in the last decade, albeit well below the absolute increase stemming from data centres. The 3% increase in industry demand between 2015 and 2023 reflects a shift towards more electricity-heavy industries such as pharmaceuticals and tech manufacturing, closures in some heavy industries and ongoing energy efficiency improvements. In the transport sector, demand grew sixfold during 2015-2023 with the adoption of electric vehicles, but it still represents less than 2% of Ireland's electricity consumption.

Final energy consumption by source and sector in Ireland, 2023



Sources: IEA (2025), Electricity Information; IEA (2025), Energy End-Uses and Efficiency Indicators.

While the electrification of key end uses remains limited in Ireland, particularly in road transport and heat, growth potential is significant owing to the country's supportive targets and the wide commercial availability of electric technologies. Despite the rising adoption of electric vehicles, which made up 25% of new registrations in 2024, only 7% of all cars on Ireland's roads are electric, including battery electric and plug-in hybrid models.

In the residential sector, 72% of energy used is still sourced from fossil fuel-based technologies that could be replaced by heat pumps or – in densely populated areas – district heating systems. Similarly, approximately 70% of the heat used in industry is below 300°C, so its production could be electrified using technologies such as heat pumps and electric boilers. Indeed, Ireland's Roadmap for the Decarbonisation of Industrial Heat emphasises that electrifying a large share of the 7 TWh of low- to medium-temperature industrial heat demand is essential to achieve the country's decarbonisation goals and will also reduce fossil fuel import dependency.

Selected 2030 climate and energy targets related to end-use electrification

Sector	Actions and metrics by 2030
Transport	• 845 000 private EVs (30% of total private passenger car fleet and 100% of new registrations) • 95 000 commercial EVs (20% of the large-goods vehicle fleet) and 3 500 heavy-goods vehicles (30% zero-emissions share of new heavy-duty vehicle registrations) • 1 500 electric buses and expansion of electrified rail services
Industry	• Reduce fossil fuel use to 30% of final consumption • 70-75% share of carbon-neutral heating in total fuel demand
Buildings	• Install heat pumps in 280 000 new and 400 000 existing dwellings

Source: Government of Ireland (2024), Climate Action Plan 2024.

Ireland's electricity demand outlook

Projections for Irish electricity consumption vary widely, reflecting uncertainties around data centre expansion and the pace of end-use electrification. According to the projections of EirGrid and SONI's All-Island Resource Adequacy Assessment, the Tomorrow's Energy Scenarios (TES) and the Energy Policy Modelling Group (EPMG),[3] annual consumption could range from 37 TWh to 47 TWh for 2030, while expectations for 2035 vary between 50 TWh and 69 TWh.

[3] The Energy Policy and Modelling Group (EPMG) at University College Cork is an academic research unit specialising in energy system modelling and policy analysis to provide evidence-based insights that inform national energy strategy and decision-making in Ireland.

The transport sector presents the widest range, with TES estimates as low as 3.6 TWh and EPMG projections up to 14.2 TWh. Residential demand is more consistent, with the TES forecasting 13-16 TWh and the EPMG projecting close to 13 TWh. For industrial demand, the TES anticipates a range of 8.3-12.3 TWh by 2035, and EirGrid expects data centre consumption to reach 13-15 TWh.

The uncertainties affecting Ireland's electricity demand outlook – particularly regarding electrification, population growth and data centres – makes power system planning more complex. Establishing a system that can respond and adapt to these variables will require timely investment in generation, grid infrastructure and system flexibility to ensure that it remains balanced and secure. If demand increases more rapidly than anticipated, particularly from large energy users, careful policy decisions may be required to manage potential tensions among economic growth, housing development, climate ambitions and system reliability.

Ireland is a frontrunner in wind energy integration, with gas providing baseload and essential system services

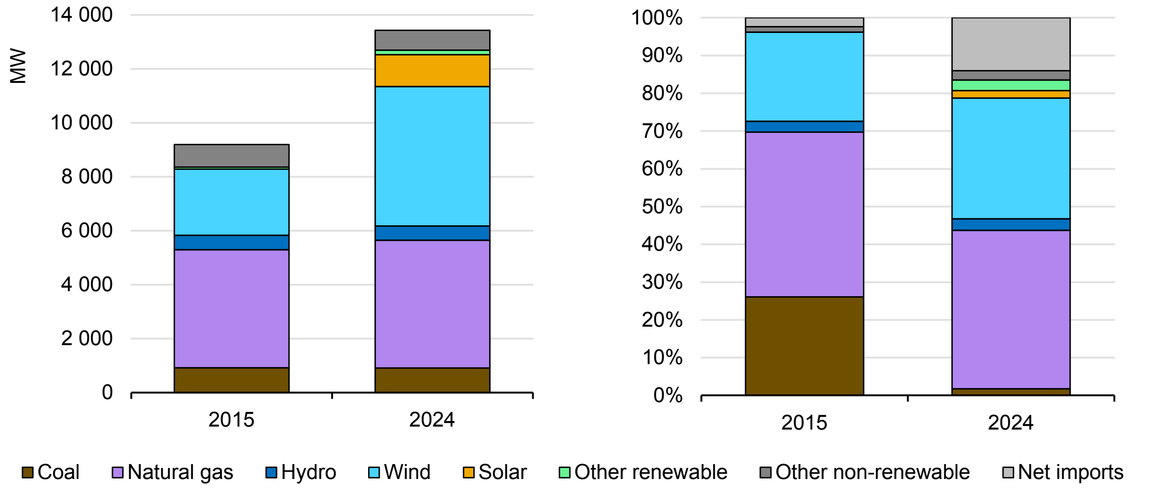
Ireland's generation mix has shifted significantly in the past decade, with wind being increasingly deployed as coal is phased out. Thanks to strong policy support and high-quality wind resources, onshore wind capacity more than doubled from 1.9 GW in 2013 to 4.9 GW in 2024, while solar PV reached 1.7 GW in June 2025 and battery storage capacity grew to more than 750 MW in early 2025, both expanding from virtually zero in the early 2010s.

Hydropower capacity has remained stable at around 530 MW, while offshore wind is only just emerging, with 25 MW installed as of 2023. As a result, renewable energy sources provided about 40% of total electricity supply in 2024 (including imports). Ireland has also completed its coal phaseout, with Moneypoint Power Station formally ceasing coal-fired power generation in June 2025.

Wind power integration in Ireland

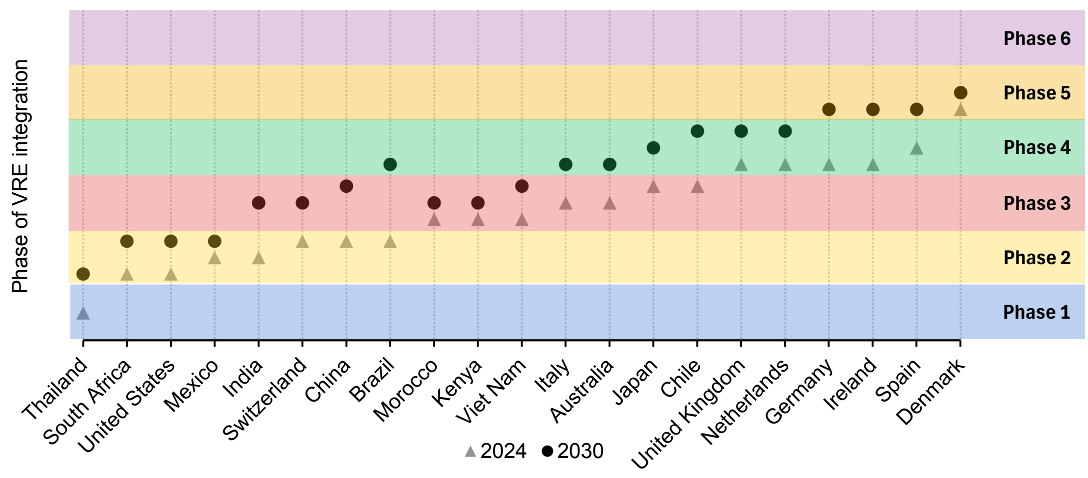
Significant wind deployment has made Ireland a frontrunner in variable renewable energy (VRE) integration. In 2024, it had one of the highest shares of solar and wind generation in the world at about 34%, with wind accounting for roughly 32% of total electricity supply (including imports). Integrating large VRE shares is important for several reasons: not only is it crucial to achieve decarbonisation targets, but it can help meet rising electricity demand from households and businesses. However, the supply variability of VRE challenges traditional power system operations, creating a need for greater flexibility through, for instance, demand response, energy storage, new interconnections and grid enhancements.

Electricity capacity mix (left) and generation mix (right) in Ireland, 2015-2024



In rapidly enlarging the solar and wind share in its electricity mix, Ireland has become a leader in VRE integration. As growth continues, the country will need to take further measures to ensure the power system can accommodate VRE efficiently. The IEA phases of VRE integration framework outlines six phases of increasing system impact from VRE, each requiring progressively more advanced stability and flexibility solutions. Since at least 2015, Ireland has been in Phase 4, an advanced phase in which secure VRE integration requires more sophisticated grid management and flexibility measures. As of September 2024, it was one of only six countries the IEA categorised as Phase 4 or higher, out of those assessed. Ireland's target of 80% renewable electricity by 2030 suggests a jump to Phase 5.

Phases of variable renewable energy integration in selected countries, 2024 and 2030



The role of natural gas in Ireland's power system

While renewables are becoming increasingly important in Ireland's power system, natural gas remains the dominant energy source for electricity generation. Gas-fired capacity has grown from approximately 3 700 MW in 2013 to 4 730 MW in 2024, with its share of electricity supply decreasing slightly from roughly 44% in 2015 to 42% in 2024. In addition to providing energy, gas-fired and other dispatchable power plants continue to deliver a range of essential system services such as inertia and flexibility, making them critical for electricity security.

Looking ahead, the role of gas is expected to evolve, with a growing focus on adequacy and system flexibility rather than on bulk electricity supply. To support this shift, Ireland has started procuring more flexible natural gas power plants. A key instrument enabling this transition is the Capacity Remuneration Mechanism (CRM), which provides financial incentives to ensure the availability of capacity resources that may operate infrequently and earn limited revenues through energy markets alone.

In the latest CRM auction for the 2028-2029 delivery year, over 70% of total awarded capacity went to gas-fired generation, while among new generation, 44% was allocated to gas. For example, two flexible gas plants with a total capacity of 200 MW were commissioned in 2024 to enhance rapid-response capabilities. Additionally, a new 293-MW gas peaker is being procured for the Dublin area, designed to operate just 22 to 95 hours per year to provide critical backup during peak demand or low renewable output periods.

Ireland's continued reliance on natural gas provides valuable system flexibility and helps the system meet demand, especially during periods of low renewable energy output. However, this dependence extends the country's exposure to international gas market volatility, which can contribute to electricity price fluctuations and complicate efforts to reduce emissions. As renewable energy deployment accelerates, calibrating the role of gas in the generation mix will remain a central challenge requiring the careful alignment of energy security, climate and affordability objectives.

Energy security risks are becoming more diverse with system transformation

Managing Ireland's surging electricity demand will require the continued fundamental transformation of the power system, with renewable energy at its core. Wind and solar offer the dual benefits of meeting growing consumption while reducing the country's dependence on imported oil and natural gas. However, operating a power system with such high VRE levels introduces new complexities. Achieving 80% renewable electricity by 2030 will demand not only massive infrastructure buildouts but also sophisticated management of a system that will regularly operate on a very high percentage of converter-connected resources (95% or more).[4] While this transformation is happening, traditional risks will persist because the relatively small, island-based system currently has interconnections with the United Kingdom only.

Meanwhile, emerging challenges will compound the system's preexisting vulnerabilities: global supply chain concentrations threaten the timely delivery of assets such as wind turbines and grid infrastructure, while increasingly severe storms are testing the resilience of new and existing assets. Balancing these dynamics will require careful consideration to decide how quickly to scale up; where to prioritise investment; and how to allocate the risks and costs of system transformation among stakeholders.

Stability and system adequacy

Ireland is entering a period of rapid power demand growth, driven by rising electrification, population increases and the proliferation of data centres. This trend is expected to persist for some time, raising supply-side pressure and making it more complicated to ensure system adequacy. While Ireland has instruments such as the All-Island Resource Adequacy Assessment in place to determine investment needs for new capacity and assess future adequacy risks, the scale and speed of demand growth mean that maintaining adequacy will require ongoing investment to ensure that generation capacity and grid infrastructure are expanding quickly enough.

At the same time, stability challenges are increasing as Ireland's power system shifts to near-total reliance on converter-connected technologies. Most new capacity – whether it be wind, solar, battery storage or HVDC interconnections – is converter-connected, meaning it does not inherently provide the inertia and frequency support offered by traditional synchronous generators. Ireland's share of converter-connected resources is already one of the highest globally, and it is expected to increase significantly in upcoming years.

When a relatively small island-based system such as Ireland's transitions to variable renewable energy, the need for alternative system service sources is amplified. Through initiatives such as the DS3 Programme and the Low Carbon Inertia Services auction, Ireland has already procured essential services such as fast frequency response, synthetic inertia and black start capability through battery storage, demand-response systems and synchronous condensers.

Looking ahead, enabling the secure operations of a renewables-led system with high shares of converter-connected energy sources after 2030 will require a broad

[4] Converter-connected resources such as VRE generators are assets that are connected to the electricity grid through a converter.

mix of flexibility, stability and system service solutions, including energy storage, demand response, interconnections, synchronous condensers, and both thermal and low-carbon dispatchable generation. EirGrid's and SONI's Operational Policy Roadmap supports this transition, targeting secure operations with converter-connected resources able to contribute as much as 95% of Ireland's electricity at any given moment (i.e. instantaneously) by 2030 and nearly 100% by 2035. Dedicated efforts will be essential to maintain both adequacy and stability as Ireland continues to decarbonise and electrify its economy.

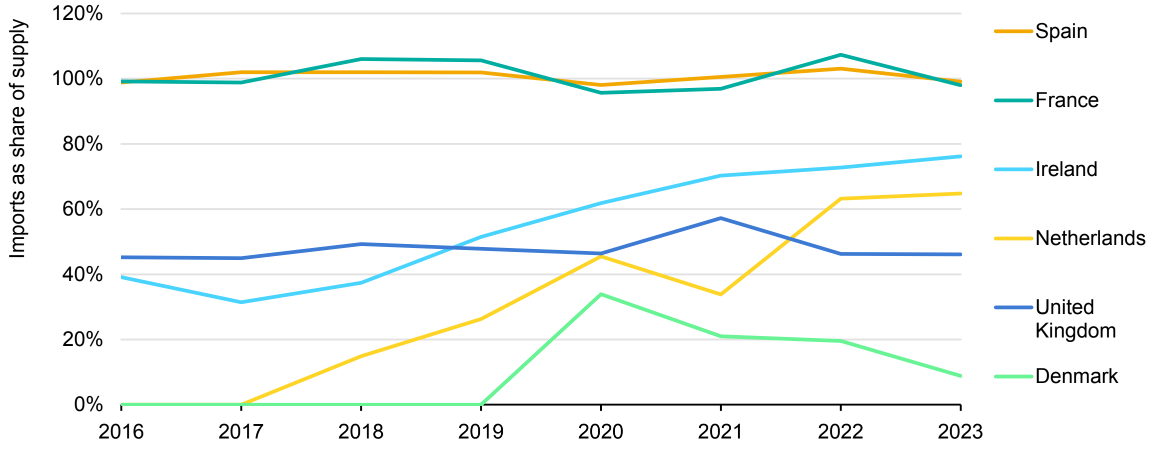
Reliance on imported fossil fuels

One of Ireland's key energy security risks is its high dependence on imported fossil fuels, particularly natural gas. It is a critical fuel in the energy sector, with power generation consuming nearly 60% of total natural gas supply. Dispatchable gas-fired power plants provide valuable adequacy and system services, contributing significantly to energy and system security. However, since gas plants also expose Ireland to price volatility and supply risks related to infrastructure failures and market shocks, the government views reducing gas consumption and dependency as a key energy security measure.

Compared with other European countries, Ireland's natural gas import dependence is relatively high and growing, and its supply diversity is notably low. Its net import reliance grew from 40% in 2016 to 76% in 2023, reflecting shrinking domestic supplies. While about 20% of current demand is met domestically by the Corrib gas field, its production has been declining and it is expected to close not long after 2030. No new domestic sources will replace it, as Ireland has banned new gas exploration. Furthermore, turf and coal, which were partially sourced locally, have also been phased out for power generation, making natural gas more important.

For comparison, imports make up 9% of Denmark's total gas consumption, 46% of the United Kingdom's and 65% of the Netherlands', and many of Ireland's import-dependent neighbours have developed more diverse supplies. For example, the United Kingdom has a very diversified gas supply that includes domestic production, several LNG import terminals, and pipeline connections with Norway, Belgium and the Netherlands.

Natural gas import reliance of Ireland and neighbouring countries, 2016-2023



Notes: Import reliance is defined as the percentage of annual net imports in observed gross inland deliveries of natural gas. Due to statistical differences, the indicator can be above 100% in countries with very high import reliance.
Source: IEA (2025), Natural Gas Information.

As Ireland receives its gas imports via two undersea pipelines from the United Kingdom, it is vulnerable to supply disruptions. Without the buffer of underground gas storage, technical failures or physical pipeline disruptions (such as that of the Baltic connector in October 2023) can quickly create supply shocks. Furthermore, Ireland's dependence on the United Kingdom for all its electricity imports compounds the risk of relying on one single external source, albeit a widely diversified one.

However, the Government of Ireland recently announced a plan for a floating storage and regasification unit to provide emergency capacity in compliance with the European Union. Yet, to continue reducing reliance on fossil fuel imports as well as the country's LNG supply vulnerabilities, the government also needs to implement actions to curb unabated natural gas use while it develops the regasification facility.

Supply chain risks

While transitioning to renewable energy will reduce reliance on fossil fuel imports, it may also introduce distinct supply chain risks for many countries that lack strong domestic manufacturing capabilities, including Ireland. This applies especially to batteries and solar panels, for which the People's Republic of China (hereafter, "China") held more than 80% of global manufacturing capacity in 2023. Similarly, the average market share of the top three producers of key minerals needed for manufacturing clean energy technologies rose to 86% in 2024. Dependency is lower for wind power, with China accounting for 50-65% of manufacturing capacity and Europe also having a well-established manufacturing base. This means significant price volatility or supply disruptions for some clean energy technologies can threaten the delivery of new capacity or raise expenses and lead times considerably.

However, conventional generation technologies are not immune to supply chain challenges either, with natural gas turbines currently being affected by longer lead times and cost increases. Due to a rise in gas turbine orders, key suppliers such as GE Vernova and Siemens Energy have indicated that deliveries of turbines ordered now cannot be expected before 2029 or 2030. At the same time, project costs in key markets such as the United States have risen to more than USD 2 400/kW, more than double what they were just a few years ago.

Expanding grid infrastructure is also challenging, as supply chains for components such as transformers and power cables are increasingly constrained. In fact, component lead times and prices have almost doubled in the past four to five years, with supply chain restrictions expected to persist. This could delay the grid infrastructure construction and reinforcements that are crucial to enable secure demand and low-carbon generation growth in Ireland. Chapter 3 explores supply chain risks in more detail.

Climate resilience

Climate resilience has always been a cornerstone of energy security. However, Ireland is increasingly subject to extreme weather events and its rising dependence on wind power is amplifying the impacts of naturally variable wind patterns. Being positioned on the periphery of the Atlantic Ocean makes the country (especially its extensive network of overhead power lines) particularly vulnerable to strong winds and severe storms. Past storms such as Éowyn, Darragh and Ophelia have already demonstrated the risks, causing widespread power outages.

At the same time, climate change is altering weather patterns, with projections indicating that storm-related rainfall intensity could increase 42-62%, especially in autumn and winter, if global temperatures rise 2°C by mid-century. Similarly, flood risks could increase as winds and storms intensify, especially in coastal areas such as southern Ireland, where infrastructure was damaged during storm Ellen in 2020. To protect energy systems, targeted adaptation measures such as elevating, waterproofing or relocating vulnerable assets will be essential.

Additionally, wind power now plays a central role in Ireland's electricity system, exposing it to the impacts of windspeed fluctuations. Prolonged wind droughts that occur roughly once per decade and last up to 20 days pose significant challenges, underscoring the need for greater system resilience, flexibility and backup capacity to maintain energy security. Chapter 4 explores climate resilience in greater detail.

Securing Ireland's electricity future will require co-ordinated infrastructure delivery and operational innovation

Ireland will have to tackle diverse challenges to maintain energy system security to 2035. Its power system is already a global leader in VRE integration, but it will be under pressure to reduce fossil fuel reliance and reach the 80% renewable electricity target while at the same time meeting rising demand and keeping cost increases to a minimum. Achieving all these objectives will require the country to expand its generation capacity and grid infrastructure while building on already-advanced operational practices. It will be necessary to deliver key infrastructure projects in a timely manner between now and 2030, and to implement innovative operational practices to run the renewables-dominated system effectively by 2035.

Up to 2030, the immediate priorities are to manage rapidly growing electricity demand and ensure system adequacy in an already-high renewable electricity mix, using investments and infrastructure that can realistically be delivered quickly. Electricity security hinges on the timely buildout and delivery of new generation capacity; on unlocking additional flexibility potential; on energy efficiency; and on further expansion of advanced operational practices – all within the current planning, permitting and regulatory frameworks.

Today's policies will largely shape the development of electricity grids, demand, storage and generation beyond 2030, with implications becoming very clear by 2035. Under Ireland's current targets and projections, the policy focus will have to shift strongly towards enabling secure system operations at a converter-connected resource penetration of nearly 100%, with natural gas being used mainly for security purposes. This power system will require even greater flexibility, infrastructure buildouts and a fit-for-purpose market and regulatory framework, as well as innovative operational practices not yet implemented at that scale in any of the world's large power systems. A framework that distinguishes short-term delivery challenges from long-term system transformation will provide a conceptual structure for Ireland to assess its electricity security needs over time.

State of play

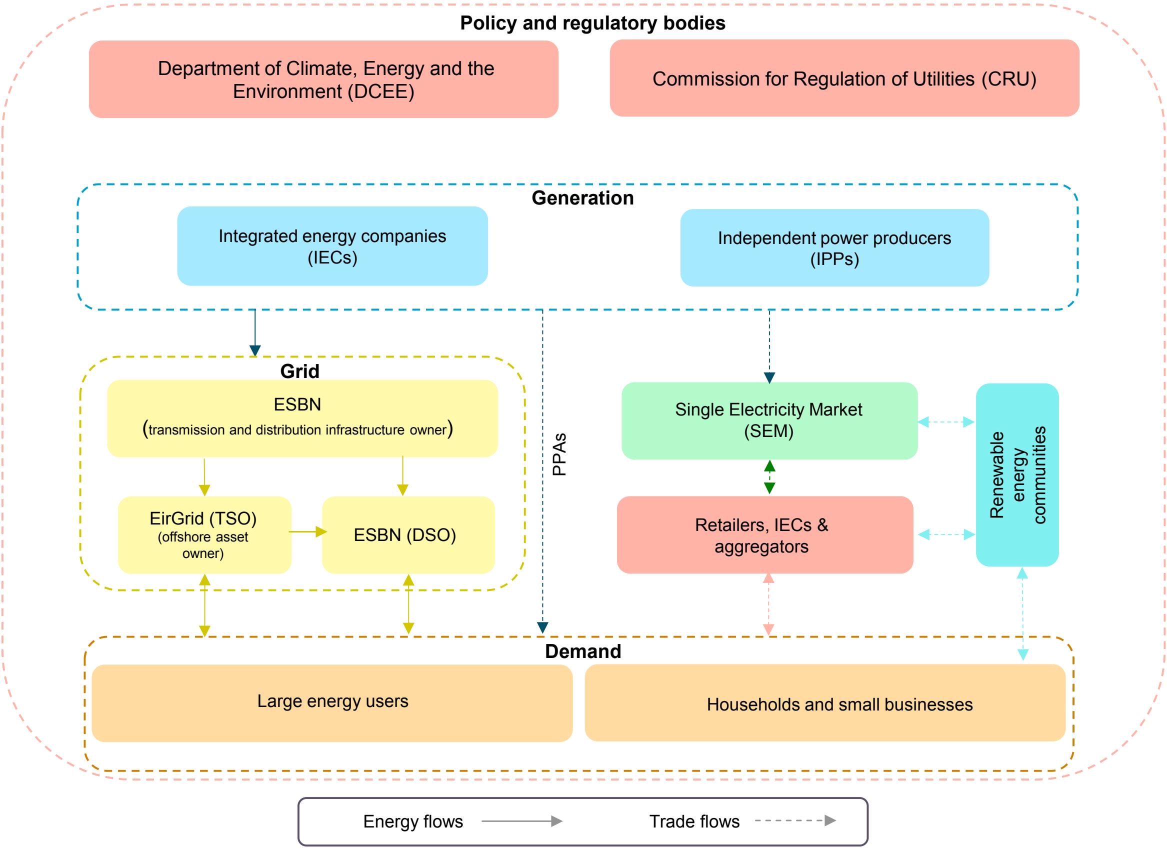
Gaining a clear understanding of Ireland's current power sector challenges and trends is essential to assess its electricity security through 2035. As part of the All-Island power system with Northern Ireland, Ireland's institutional structure is unique, with operational, regulation and policy responsibilities shared between both countries. Within this framework, Ireland has emerged as a leader in VRE integration, though natural gas continues to play a central role in the power system. However, high gas and electricity prices are raising affordability concerns.

The country's electricity supply sources are becoming more diversified thanks to expanding interconnector capacity, but grid congestion is more pronounced, resulting in long connection queues and curtailment. At the same time, recent generator outages and extreme weather events have exposed system vulnerabilities, highlighting the need for Ireland to develop a holistic strategy to ensure energy security in the coming decade and beyond.

Ireland's electricity security depends on co-ordination among multiple stakeholders and jurisdictions

Together with Northern Ireland, Ireland is part of the All-Island Single Electricity Market (SEM), consisting of two independently regulated transmission grids but one wholesale market. A wide range of stakeholders from both countries is involved in the Irish power sector, ensuring that electricity demand is met reliably. As an island covered by two jurisdictions, close cross-border co-operation is necessary for the power system to function effectively. Planning and policy efforts must be aligned; regulator and system operator practices must be harmonised; and electricity flows must be jointly managed across the two jurisdictions.

Ireland's electricity market structure, and energy and trade flows



Note: ESBN = ESB Networks.

Within Ireland, the Department of Climate, Energy and the Environment (DCEE) is the main government body responsible for developing energy and climate policies aligned with EU regulations. It plays a vital role in the power sector, advancing the country's energy transition and security through initiatives such as the Climate Action Plan, Offshore Renewable Energy Development Plan, the National Offshore Renewable Energy Designated Maritime Area Plan and the Energy Security in Ireland to 2030 strategy. The DCEE also collaborates with its Northern Irish counterparts, regulators and system operators to ensure that reliability standards align with policy goals, and to guarantee that these standards are upheld. It financially supports the creation of resilient, adaptable infrastructure and manages regulations that ensure continuous energy supply.

As the All-Island system's wholesale electricity market, the SEM facilitates energy trading and safeguards system reliability through energy, capacity and ancillary service mechanisms. Irish and Northern Irish stakeholders jointly operate the SEM. EirGrid and SONI manage market operations through the market operator SEMO, and governance is overseen by the SEM Committee, comprising both regulators and two independent members. Energy is traded through various markets (day-ahead, intraday and balancing markets), while the SEM also enables trading across the island. To prevent significant capacity gaps, the Capacity Remuneration Mechanism uses auctions to procure generation capacity 1-4 years in advance.

To ensure system reliability, Ireland's transmission and distribution grids are regulated by the Commission for the Regulation of Utilities (CRU) and operated by EirGrid and ESB Networks (ESBN). The CRU oversees both entities, setting revenue allowances and network charges to balance efficiency with investment needs for system security. In Northern Ireland, the Utility Regulator (UR) regulates the electricity, gas, water and sewerage industries, SONI manages the transmission grid and Northern Ireland Electricity Networks oversees distribution. ESBN owns, builds and maintains Ireland's transmission and distribution grids, while responsibility for offshore grids falls initially to offshore wind developers before being transferred to EirGrid.

A diverse energy market allows consumers of all sizes to access and trade electricity through retailers, and it also gives access to emerging consumer models such as aggregators and energy communities. This diversity enhances competition and consumer choice, and it improves grid flexibility and resilience. Retailers, licensed and regulated by the CRU, purchase electricity from the SEM and sell it to consumers. Fifteen suppliers currently share the market, with Electric Ireland holding 40%. The market also includes several integrated energy companies (IECs), and renewable energy communities are emerging as decentralised enablers of local generation.

High energy prices reflect import dependency and raise affordability concerns

Energy security is not only about energy availability, but also affordability. Thus, following Russia's full-scale invasion of Ukraine, affordability rose to the top of the political agenda in Ireland and in Europe as a whole. While gas prices have fallen since the European energy crisis in 2022, they were still double pre-crisis levels across Europe in Q2 2025. As natural gas plays a key role in the wholesale electricity price in Ireland, with gas setting the price for about 80% of hours in 2022, ripple effects on the affordability of both natural gas and electricity are significant.

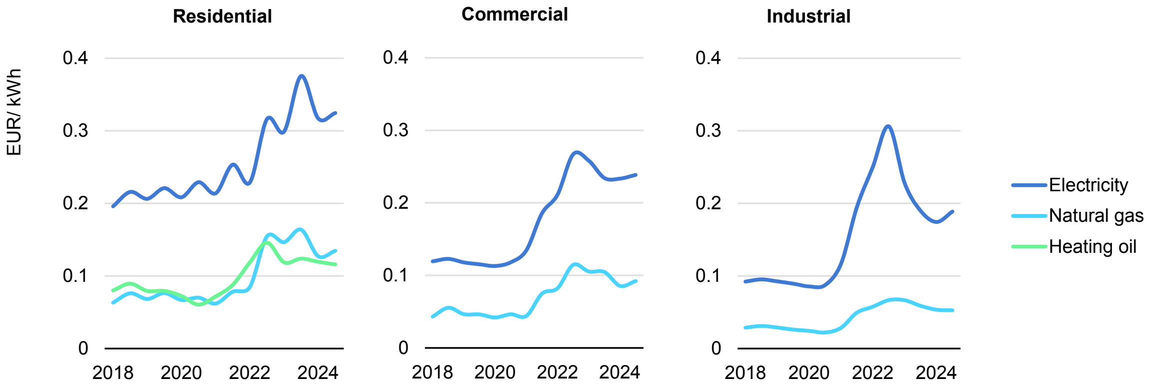
Consequently, Ireland is among the European countries with the highest electricity and gas prices, with household electricity bills 22% above the EU average and gas 10% above. The price of heating oil, still used by over one-third of households, also almost doubled from EUR 67/MWh to EUR 110/MWh between 2021 and 2025. Similar increases have affected small businesses and energy-intensive industries, with prices also significantly above the EU average. This has worsened industrial competitiveness, causing 40% of manufacturing businesses in Ireland to cite energy costs as a key challenge in 2024.

Important components of high gas and electricity prices are network costs and other charges. Because it is expensive to serve a relatively small, dispersed population, Ireland's network costs are among the highest in Europe, making up 31% of domestic electricity bills and 24% of gas bills. In addition, household electricity bills contain a Public Service Obligation (PSO) levy of EUR 36/year to support renewable energy generation, as well as capacity charges to finance the Capacity Remuneration Mechanism. In 2024/25, capacity charges for electricity suppliers were around EUR 21/MWh, with this cost passed on to customers in their retail prices. For natural gas, a carbon tax of around EUR 63/tonne is also levied.

Government interventions such as tax cuts and support measures can be used to provide a buffer against price spikes on energy bills. For instance, following the 2022 energy crisis, the Irish government reduced VAT on gas and electricity from 13.5% to 9%, saving households an estimated EUR 50/yr on gas and EUR 70/yr on electricity. Eligible households also received energy bill support through government rebates, which totalled EUR 1 500 between 2022 and January 2025. Responding to ongoing affordability challenges, the Irish government has also set up a National Energy Affordability Taskforce.

The increasing pressure of energy costs on Irish households and businesses underscores the importance of implementing balanced and reasonable approaches to align energy supply with demand while safeguarding affordability. Thus, when considering how to achieve industrial competitiveness and consumer protection, the imperatives of ensuring energy security, expanding grid infrastructure and renewable capacity, and accommodating growing electricity needs must also be kept in mind.

Energy prices by sector in Ireland, 2018-2024



Sources: Eurostat (2025), Energy Statistics - Prices of Natural Gas and Electricity; SEAI (2025), Energy Price Trends; SEAI (2024), Fuel Price Comparison Display Guidance.

As interconnections are important for supply diversity, additional capacity is under development

Interconnections are critical to Ireland's electricity security because they will enable the country to diversify its supply sources and enhance system resilience. As interconnectors provide access to a broader pool of generation, they support system adequacy, reduce reliance on any single fuel or technology, and have the potential to lower electricity prices. They can also make it easier to meet rising demand from consumers such as data centres and households while advancing decarbonisation. Furthermore, interconnectors can contribute to system restoration, as demonstrated during the Iberian blackout of April 2025 when they facilitated the black start of the system.

The All-Island system currently has three operational interconnectors linking it to Great Britain: the 500-MW East-West Interconnector between Ireland and Wales, the 500-MW Moyle Interconnector between Northern Ireland and Scotland, and the 500-MW Greenlink Interconnector, which began operations in January 2025 to connect Ireland to Wales.

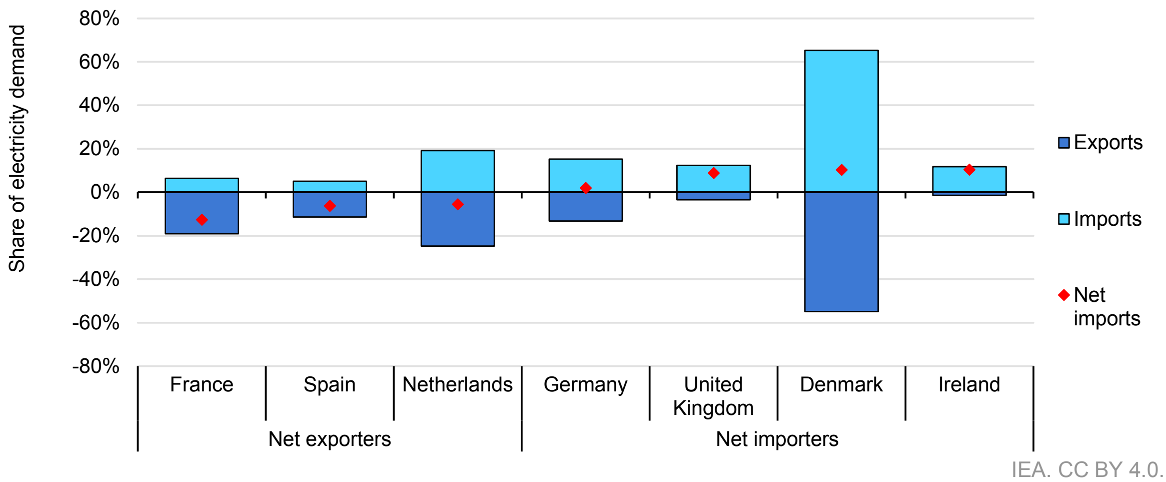
Within the island itself, one 275-kV double-circuit line and two 110-kV circuit lines connect Ireland and Northern Ireland. Due to operational constraints, secure power transfers between the two jurisdictions are typically limited to around 300 MW, restricting the system's ability to function as a fully integrated market. To address this limitation, the 400-kV North-South Interconnector slated to come online in 2031 would increase the secure transfer capacity to 1 100-1 300 MW.

Ireland's interconnectivity is relatively low and not very diversified compared with other European countries. In 2023, 15% of peak demand could be met by import capacity, but this level is expected to increase with the addition of the Greenlink Interconnector. Within the European Union, only three countries have lower or equal interconnectivity: Greece (11%), Italy (13%) and Spain (15%). Additionally, the All-Island system is currently connected to only one single external system, Great Britain, by a non-synchronised connection. This limits real-time support from a larger grid, increasing security challenges as VRE generators displace synchronous units and heightening the need for system services such as inertia, fast frequency response and flexible backup capacity to ensure system security.

Despite Ireland's limited interconnectivity, power imports still meet a significant portion of its demand. While other countries such as Denmark and the Netherlands steadily use their interconnectors to both import and export electricity, Ireland has been predominantly a net importer in recent years. Consequently, net imports represent around 10% of demand, which is relatively high compared with other VRE-heavy systems such as Denmark (10%), the United Kingdom (9%) and Germany (2%). Other countries that have high VRE proportions (e.g. the Netherlands and Spain) are net exporters. This means that Ireland's electricity security is at risk when an interconnector trips, especially during times when imports are covering a large share of electricity demand.

Responding to this vulnerability, a strategic pillar of Ireland's electricity security agenda is interconnection network expansion. Thus, the 700-MW Celtic Interconnector with France – its first direct link with continental Europe – is scheduled to start commercial operations in early 2028. Additionally, the proposed 750-MW MaresConnect project linking Ireland and Great Britain and the 700-MW LirIC interconnectors between Northern Ireland and Great Britain aim to further strengthen cross-border capacity.

Electricity trade reliance in selected countries, 2023



Source: IEA (2025), Electricity Information.

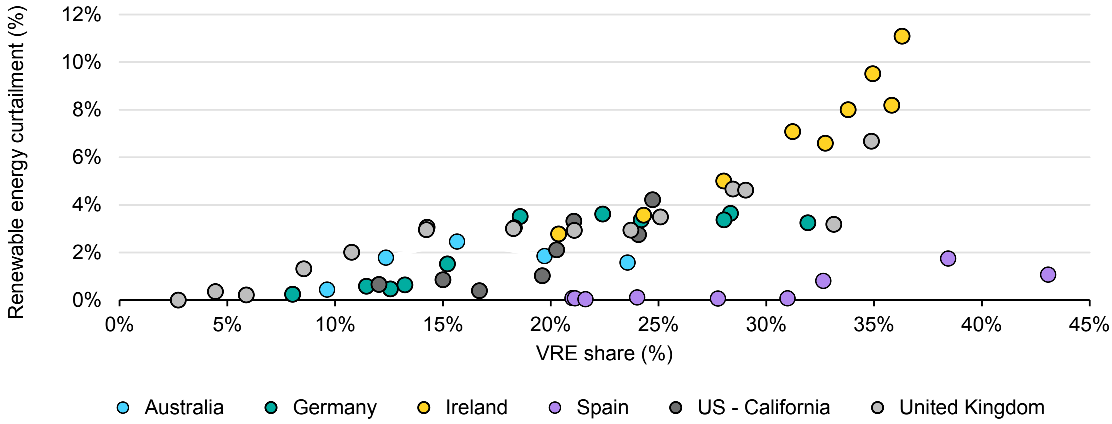
However, a possible challenge to interconnection expansion is interconnector delivery delays. Regulatory and permitting holdups have already impacted key infrastructure projects such as the Greenlink Interconnector, which was postponed from its original 2023 target to early 2025. Similarly, the proposed North-South Interconnector between Ireland and Northern Ireland has been delayed until 2031.

Grid congestion is leading to technical curtailment and connection queues, though alleviation measures are in place

Ireland's power system is under growing pressure because renewable energy is being generated far from where it is used. This geographic imbalance, combined with limited grid capacity and slow designing and delivery of grid reinforcement, is leading to more frequent technical curtailments.[5] Consequently, congestion management costs have increased significantly for the All-Island system, jumping from EUR 186 million in 2015 to EUR 592 million in 2025.[6] Correspondingly, wind curtailment levels within Ireland rose from about 2.4% in 2011 to a peak of 11.4% in 2020 and have since been fluctuating between 7% and 10%. In 2024, transmission congestion alone was responsible for almost half of all wind energy curtailments. Most of the remaining curtailments resulted from system security considerations (for instance to keep the minimum number of conventional generators operating) or happened during periods of high renewable energy generation and low demand. System non-synchronous penetration (SNSP), rate of change of frequency (ROCOF) and inertia requirements provoked only a marginal amount of technical curtailment.[7]

[5] Technical curtailment in this report refers to reducing generator output (referred to in Ireland as "dispatch down") in response to local network conditions ("constraints") or system-wide security issues ("curtailments").
[6] EirGrid derived its congestion cost estimates from power system modelling that incorporated projected dispatch balancing costs, including constraint costs, and EUR 158 million for potential Article 13 (EU Regulation 2019/943) payments. The forecast also adjusted for system outages, renewable energy integration impacts and a EUR 66.41 million reduction for over-recovery from prior years.
[7] System non-synchronous penetration (SNSP) measures the share of electricity from non-synchronous sources (e.g. wind, solar, batteries, HVDC imports) at a given time. Rate of change of frequency (ROCOF) reflects how quickly grid frequency shifts from its nominal value. Inertia requirements define the minimum spinning reserve needed to slow frequency changes and maintain system stability during disturbances.

Annual VRE shares in generation and technical curtailment in selected countries and regions, 2010-2024



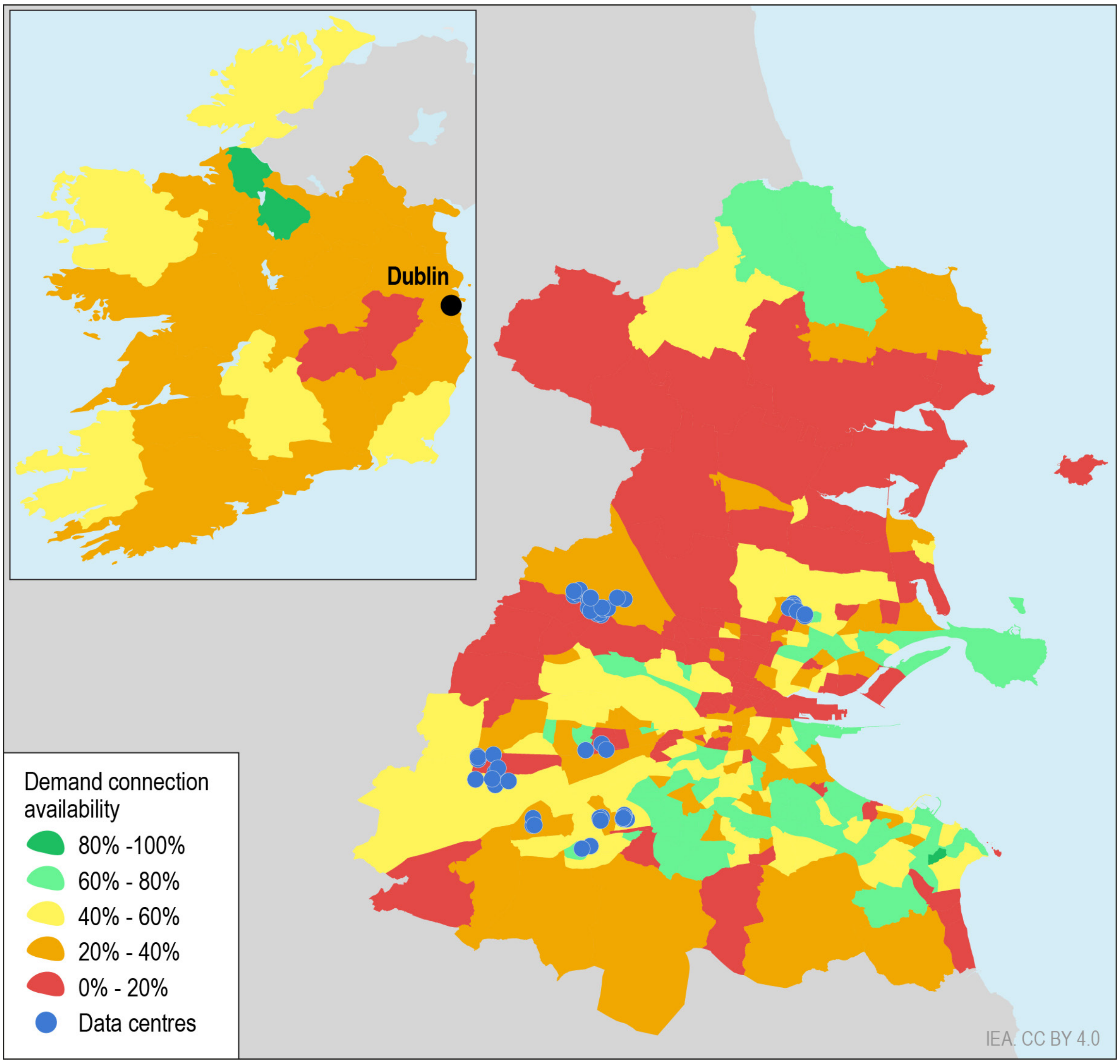
Notes: Each dot represents one year. Data points indicate officially reported curtailed or constrained energy generation and combine various schemes, depending on the country. VRE refers to solar PV and wind unless otherwise specified. The United Kingdom includes wind only. Technical curtailment is the dispatching-down of renewable energy generation for network or system reasons; generation that was dispatched-down due to economic or market conditions is not included. The graph covers 2010-2024, and the range varies among countries depending on data availability. Values for 2024, when included, are based on daily, monthly or quarterly data up to June.

Source: IEA (2024), Renewables 2024.

Continuous demand growth in the Greater Dublin area, driven primarily by data centres, has outpaced grid upgrades, leading to long connection queues. Nearly all the 2.2 GW of operating and contracted data centre demand in 2024 was concentrated in Dublin, where data centres now consume 50% of locally generated electricity. However, Dublin needs to be connected to generation assets across the island to meet this demand, creating transmission network congestion. As a result, around 1.9 GW of additional data centre capacity was awaiting grid connection in 2022, leading several operators to turn to onsite power generation. As of 2024, 7 of 82 data centres had connected to the gas network for onsite generation.

To address growing pressure on the power system, Ireland has taken targeted measures to manage large new loads. In 2021, the CRU advised a more restrictive approach to new data centre connections, and in 2025 it proposed a scheme requiring them to provide onsite power generation or storage equivalent to their demand capacity. Under the CRU's 2025 draft decision paper, data centre proposals are to be assessed case by case, evaluated based on grid capacity and security; whether they have onsite or nearby generation or storage; whether they provide demand-side flexibility; and their proximity to renewable energy sources.

Demand connection availability across Ireland (left) and in Dublin (right), 2024



Notes: Shading indicates the percentage of available transformer capacity for demand at all substations within the specified region. The Ireland map aggregates only high- and medium-voltage connections, while the Dublin map aggregates all connections. The blue dots in the Dublin map indicate the location of data centres.

Sources: ESB Networks (2024), Availability Capacity Heatmap; Data Center Map (2025), Dublin Data Centers; Tailte Éireann (2022), Electoral Divisions – National Statutory Boundaries – 2019

Generator outages and extreme weather have stress-tested the Irish power grid in recent years

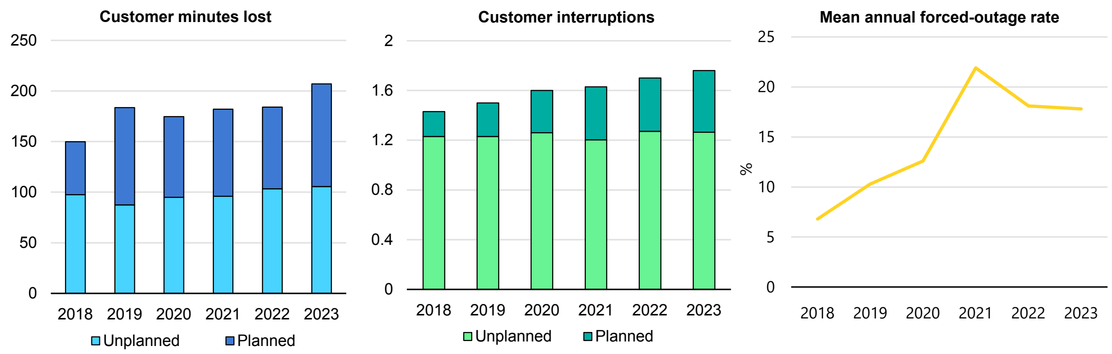
Ireland's power generation fleet has been experiencing more planned and unplanned outages recently, leading to reliability concerns. Consideration of these disruptions has been more acute since Ireland's 2021 reliability crisis, precipitated by several stress factors: insufficient new capacity; Covid-19 restrictions on planned maintenance; the retirement of ageing generators; the failure of two power plants; and increasing demand. In response, the CRU introduced several emergency policies that involved securing temporary emergency generation (TEG) capacity and extending the operational lifetime of older thermal units.

Key reliability indicators paint an improving – but still slightly risky – picture of the past several years. The loss of load expectation (LOLE) – a measure of the number of hours per period demand is expected to exceed available supply – has improved significantly since 2021/22. For the winter of 2022/23 it was expected to be 51 hours, falling to around 4 hours for the winter of 2024/25, largely owing to the implementation of out-of-market measures for flexible capacity such as temporary emergency generation. During this time, Ireland tightened its reliability standard to align with EU norms and enhance security of supply, reducing the permissible LOLE from eight to three hours per year. At 3.6 hours, the projected LOLE for the winter of 2024/25 remained above the reliability standard.

Other reliability indicators are worsening in recent years, pointing to growing system strain. There has been a rise in customer interruptions and customer minutes lost, mainly because of planned outages for system upgrades and maintenance. Importantly, storm data is excluded from trend analysis to avoid masking underlying reliability issues. The EU Agency for the Cooperation of Energy Regulators (ACER) has flagged the risk of high forced-outage rates for generators in Ireland, which could create challenges at times of high demand and low wind output. Industry sources attribute this largely to the ageing of thermal units and their increasing operational burden due to changes in the generation mix.

Since Ireland's power grid is susceptible to the effects of extreme weather, storms are the main cause of unplanned outages. The network's configuration and geography increase its vulnerability: for instance, Ireland has a high ratio of overhead to underground electricity lines – roughly 6:1, compared with 2:1 in other European systems – making it more prone to wind damage. Moreover, as high-level government officials have asserted, storms are becoming more frequent and severe as climate patterns shift, raising grid reliability and customer supply risks.

Customer minutes lost, interruptions and forced outages in Ireland, 2018-2023



Notes: Customer interruptions (CI) is the average number of power interruptions per customer greater than three minutes in a given year. Customer minutes lost (CML) is the average power outage duration per customer in a given year. To benchmark outage performance, storm days are excluded for CI and CML values. The forced-outage rate covers dispatchable generators only.

Sources: ESBN (2018), 2018 Annual Performance Report; ESBN (2019), Distribution Annual Performance Report 2019; ESBN (2020), Distribution Annual Performance Report 2020; ESBN (2021), Distribution Annual Performance Report 2021; ESB (2021), Empowering Low-Carbon Living; ESBN (2023), Distribution Annual Performance Report 2023; ESB (2022), Driven to Make a Difference: Sustainability Report 2022; EirGrid and SONI (2025), All-Island Resource Adequacy Assessment 2025-2034.

Chapter 2. Opportunities to enhance energy security through heat and road transport electrification

Electrifying its heat and road transport sectors could present Ireland with strategic opportunities to enhance its energy security while supporting climate, economic and development objectives. The country's currently heavy reliance on imported fossil fuels (for about 80% of its total energy supply) exposes it to external price shocks and supply disruptions.

Although the industry, residential and transport sectors account for approximately 85% of total fossil fuel use and around 60% of energy-related emissions, all these sectors have access to mature, commercially available electricity-based alternatives that are becoming increasingly cost-effective (e.g. heat pumps and electric vehicles). Scaling up their deployment can enhance energy security by reducing fossil fuel import dependency and can also support progress on Ireland's economy-wide decarbonisation, housing and economic growth goals.

Nevertheless, while electrification can reinforce energy security, it also introduces new power system challenges. For instance, as electrification accelerates, residential, industry and transport electricity demand will rise, and demand patterns will be reshaped. Electrifying residential and commercial space heating typically increases power demand during peak usage periods, especially in colder months, while industrial heat processes may require large loads depending on process needs. If not properly managed, these shifts could strain the electricity system and reinforce reliance on fossil-based generation.

However, solutions exist to enhance the flexibility potential of new electric loads and enable greater demand-response participation, if the right incentives are in place. Electrified heating, combined with thermal storage and smart electric vehicle (EV) charging, can shift demand to periods when renewable energy is abundant and prices are lower, easing peak-load pressure. This flexibility enhances energy security and maximises the value of available renewable generation.

This chapter analyses the potential energy security and decarbonisation benefits of achieving ambitious levels of heat and road transport electrification. It also highlights key barriers to unlocking this potential (e.g. high costs and slow grid infrastructure development) and discusses the importance of managing electrification growth to mitigate electricity security risks.

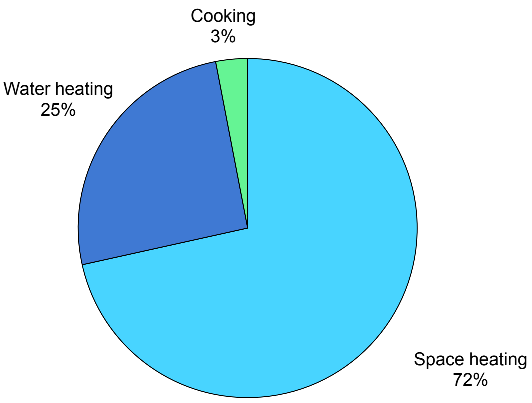
Heat and road transport electrification: Potential and benefits

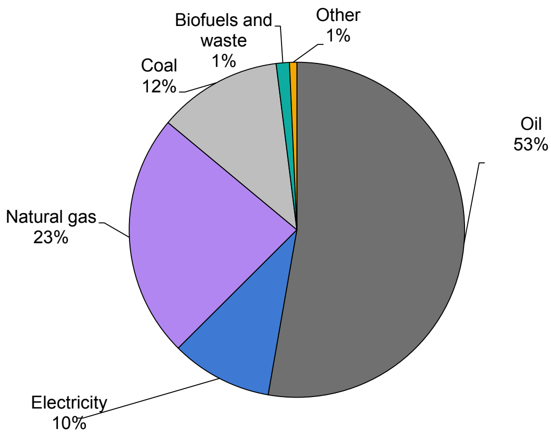
This section examines Ireland's opportunities and potential to enhance energy security by displacing imported fossil fuels for space and water heating in buildings; for industrial process heat; and for road transport. It also estimates electricity demand and associated direct CO_2 emissions reductions under ambitious electrification scenarios.

New policies encourage residential consumers to replace fossil-based technologies with heat pumps

In Ireland, residential heat is used mainly for space heating (72%) and water heating (25%). Half of this energy is supplied by oil and oil products (in which kerosene dominates at almost 70%), with natural gas contributing 27%. Although its building stock is relatively young, Ireland has the highest share of oil in space heating among IEA countries, partly because it has a dispersed population and a relatively high share of buildings in rural areas, many of which are not connected to the gas network.

Residential sector shares of end-use heat (left) and energy sources (right) in Ireland 2023





Source: Analysis based on IEA (2025), Energy End-uses and Efficiency Indicators.

Ireland introduced several regulations recently to accelerate the phaseout of fossil fuels in the residential sector. For example, it banned the installation of oil-fuelled boilers in new buildings from 2022 and gas boilers from 2025. Fossil fuel heating systems can be replaced by heat pumps, with Ireland's Climate Action Plan targeting 215 000 units by 2025 and 680 000 by 2030. Meeting these targets will require a significant increase in heat pump sales, given that Ireland's total heat pump stock was approximately 151 000 units in 2024, with roughly 37 000 units added that year.

In densely populated urban areas, low-emission heat (e.g. from waste, biomass and heat pumps) can also be distributed through district heating systems. Furthermore, solar PV-to-heat systems, such as PV modules connected directly to an electric resistance water heater, are another simple, reliable and cost-competitive option for water heating.

Regarding cost, buying a residential heat pump can be financially challenging for households because the upfront costs are relatively high compared with oil and gas boilers.[8] To tackle this barrier, the Sustainable Energy Authority of Ireland (SEAI) provides a range of grants to households, including several schemes for heat pump installation. In 2022, SEAI grant support for air-to-water heat pumps rose significantly, from EUR 3 500 to EUR 10 500 for homeowners upgrading to a heat pump as part of a deep retrofit project. Furthermore, the SEAI reported that its support for heat pumps across all schemes was 65% higher in 2023 than in 2022.

Potential benefits from residential heat electrification

In the residential sector, replacing all existing fossil fuel boilers with heat pumps has the technical potential to reduce annual fossil fuel use by 74 PJ (1 800 ktoe), saving Ireland an estimated EUR 1 billion per year in fuel import costs. From 2025 to 2035, considering the lifetime of existing heating systems and the cost of replacing end-of-life boilers with heat pumps, cumulative direct fossil fuel savings would total about 3 Mtoe.

Compared with fossil fuel-based options, a large-scale switch to heat pumps implies an additional investment of about EUR 400 million annually at the national level, but this expenditure would be fully or partially recompensed by future energy savings. In turn, assuming an average coefficient of performance (COP) of 3,[9] replacing all fossil fuel-fired boilers with heat pumps would create 4.3 TWh of new electricity demand (31% of Ireland's renewable electricity generation in 2023), concentrated around the winter months.

However, additional electricity demand for space and water heating is flexible thanks to the thermal inertia of buildings (especially well-insulated ones) and

[8] For 2023, the SEAI reported a median heat pump retrofit cost of EUR 14 868, which is about three times the cost of a fossil fuel-fired boiler.

[9] The COP is the ratio of useful energy delivered (i.e. heating or cooling output) to energy put in (generally electricity). The higher the COP, the more efficient the device is at transferring heat.

because air-to-water heat pumps can be used in combination with hot water tank storage to enable load shifting. Hot water tanks are affordable and widespread in Europe and are a common feature in almost every home in Ireland, but they might need to be better insulated to be more suitable for longer-term heat storage purposes.

The amount of thermal energy stored in 150 000 medium-sized hot water tanks exceeds 1 GWh,[10] allowing demand to be shifted by several hours. Hence, distributed thermal storage units with new water heating systems can enhance electricity security and facilitate variable renewable energy (VRE) integration. In some cases, however, direct electric heating might also be a cost-effective choice. Moreover, in densely populated areas, district heating networks can be used to distribute heat from large-scale heat pumps and other renewable energy sources and also integrate thermal energy storage solutions to enable operational flexibility, with the added benefit of economies of scale.

Low-temperature heat and steam play a key role in industrial energy demand

Natural gas and fuel oil are the Irish industry sector's primary energy sources, representing 74% of total industrial energy consumption, while electricity accounts for the remaining 26%. Ireland's only alumina production plant (Aughinish Alumina) is responsible for a considerable portion of the country's natural gas consumption. The plant runs predominately on a large natural gas-fired combined heat and power system with fuel oil-based backup, but the plan is to electrify part of its energy use with a 25-MW high-pressure electric boiler that will displace close to 10% of the site's current steam demand, avoiding 5% of the GHG emissions of a conventional alternative. Aughinish Alumina was granted EU financing through the Innovation Fund for this project.

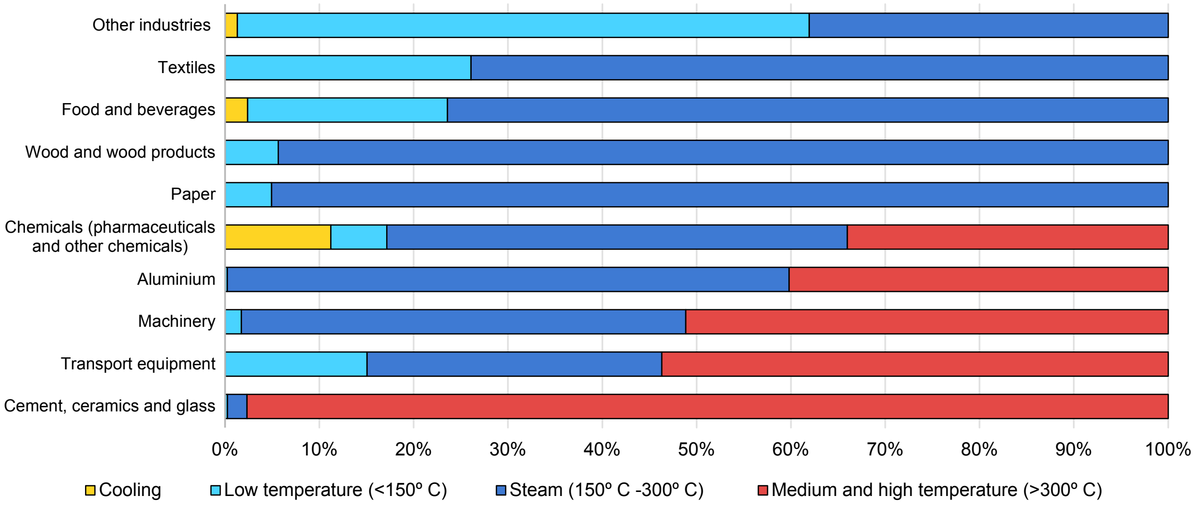
Natural gas use is spread widely across the rest of the industry sector to provide heat at various temperatures. Steam and low-temperature heat fully cover heating needs in five industries (food and beverages; wood and wood products; other industries; textiles; and paper) and at least half of the heating needs of four other subsectors (pharmaceuticals and other chemicals; aluminium; machinery; and transport equipment).

The production of heat of less than 300°C can generally be electrified, mostly through a combination of industrial-scale heat pumps (up to around 150°C, depending on the availability of waste heat) and electric boilers (e-boilers), a generally mature and commercially available technology. In fact, Ireland's Roadmap for the Decarbonisation of Industrial Heat has already recognised this

[10] Assuming an average tank capacity of 150 litres and an acceptable temperature decline of 10°C.

possibility and highlights the importance of electrifying industrial heat to displace fossil fuel use and meet national decarbonisation targets.

Industry sector fossil fuel use by temperature level in Ireland



Note: "Other industries" refers to construction, mining and quarrying, and others.
Source: IEA analysis based on data from European Commission (2024), JRC-IDEES-2021: The Integrated Database of the European Energy System.

Several other industries also have significant technical potential to electrify their low-temperature heat and steam use. Given their process temperature requirements, the entire heat demand of five subsectors (food and beverages; wood and wood products; other industries; textiles; and paper) can be electrified with commercially available technologies, potentially reducing their combined fossil fuel use by 36 PJ (equal to almost 51% of Ireland's current industry sector fossil fuel consumption). Plus, there is technical potential to electrify around 65% (3 PJ) of heat demand in the chemical subsector, 60% in the aluminium industry and 50% in machinery. Altogether, 70% (49 PJ) of the Irish industry sector's current heat demand could be electrified using commercially available technologies, leading to almost 8.5 TWh/yr of new electricity demand (1.1 TWh from heat pumps and 7.4 TWh from e-boilers).

Renewable energy options to decarbonise steam and low-temperature heat for industrial processes beyond electrification

In addition to electrifying industrial heat production, various other renewable energy solutions can be used to enhance energy security by decarbonising industrial energy use.

Solid bioenergy is by far the largest renewable heat source. Biomass combustion is a technically mature technology and its potential to deliver low- to medium-temperature industrial heat (up to around 200°C) is significant. It is used predominantly in forestry industries such as pulp and paper, where biomass is available onsite in the form of byproducts. For example, bark and sawdust generated during industrial processes could be directly combusted to produce process steam.

Biogases, both biogas and biomethane, can serve as drop-in replacements for natural gas or can be co-fired in existing boilers. **Biogas** originates from organic matter such as agricultural residues or biowaste and can be used directly by local industries to produce heat and/or power. **Biomethane,** which is biogas upgraded to nearly 100% methane by removing CO_2 and other impurities, is a drop-in substitute for natural gas. Since it could be injected into the gas grid for industrial use, no substantial modifications to existing equipment are required.

Today, biogases make up just a small part of the global energy mix – around 3% of total modern bioenergy production, equivalent to 1% of natural gas demand. However, biogases hold growing potential as competitive energy resources, especially for industries that produce significant agricultural byproducts and waste streams (e.g. food processing, paper manufacturing and distillation).

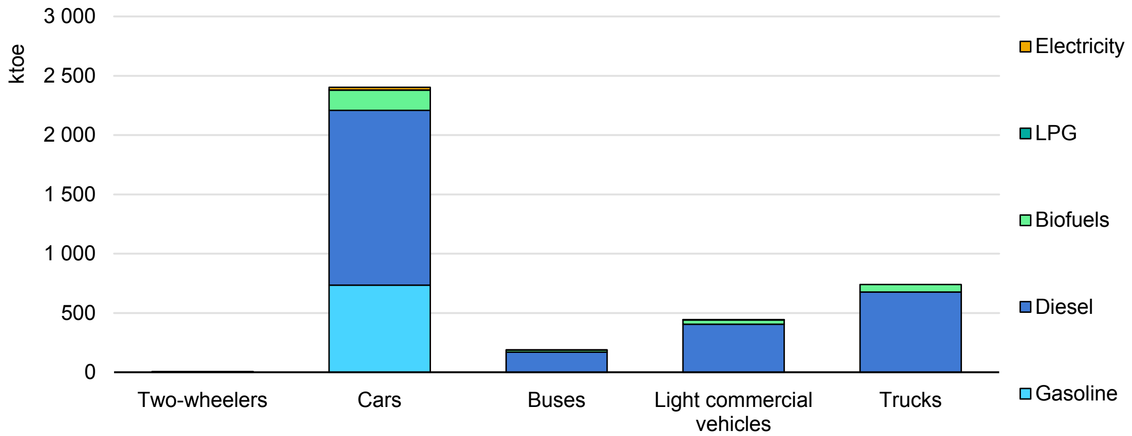
Geothermal energy can offer a stable, continuous supply of heat for industries. Conventional geothermal technology can supply both heat and electricity and is especially effective in regions with favourable geological conditions. Although geothermal energy is currently underutilised in industry due to its high upfront cost, it can technically provide low- and medium-temperature heat (generally below 200°C) with heat pumps. Meanwhile, next-generation technologies are being developed to overcome geological constraints with advanced engineering.

In regions with abundant solar energy resources, **solar thermal** is the best option for direct heat generation for heat-intensive operations, particularly in industries that use batch processing (e.g. food and beverages; textiles; and chemicals). For industrial sites with large systems (e.g. breweries), concentrating collectors have been the technology of choice. However, the use of solar heat for industrial processes (SHIP) has grown significantly the world over in recent years. In 2024, 315 SHIP systems were in operation worldwide, with a total capacity of 1 071 MW_{th} over more than 1.6 million square metres of collector area. Solar thermal technologies can deliver process heat of up to 400ºC by adapting the collector design to the targeted temperature.

Ambitious road transport electrification could slash fossil fuel use

Within the transport sector, the greatest opportunity to enhance energy security through electrification is in road transport, as it accounts for 96% of the sector's energy consumption. Petroleum fuels supplied 92% of total road transport energy used in Ireland in 2023, with cars consuming about 6% and trucks about 20%. Electricity accounted for just 1% of road transport energy consumption in 2023, although EV sales are climbing (they made up 25% of new sales in 2024). Currently, EVs – including battery electric and plug-in hybrid electric vehicles – account for 7% of the total vehicle stock (approximately 173 000 vehicles), significantly less than the 2030 target of 945 000.

Energy mix by road transport mode in Ireland, 2023



Notes: LPG = liquified petroleum gas. Two-wheelers' energy use includes only gasoline and biofuels. "Biofuels" indicates biodiesel and bioethanol. "Trucks" means heavy-goods vehicles.
Source: IEA analysis based on EC (2021), JRC-IDEES-2021: The Integrated Database of the European Energy System and SEAI (2023), Transport.

Large-scale road transport electrification can strongly reduce demand for fossil fuel imports in Ireland. In EirGrid's Self-Sustaining scenario, which achieves net zero emissions by 2040, transport electricity demand grows to 7.3 TWh by 2035. This would displace about 1 600 ktoe of direct oil derivatives,[11] or about 45% of road transport fossil fuel use in 2023, reducing direct (tank-to-wheel) CO_2 emissions by up to 5 $MtCO_2$ (45% of road transport emissions in 2023).

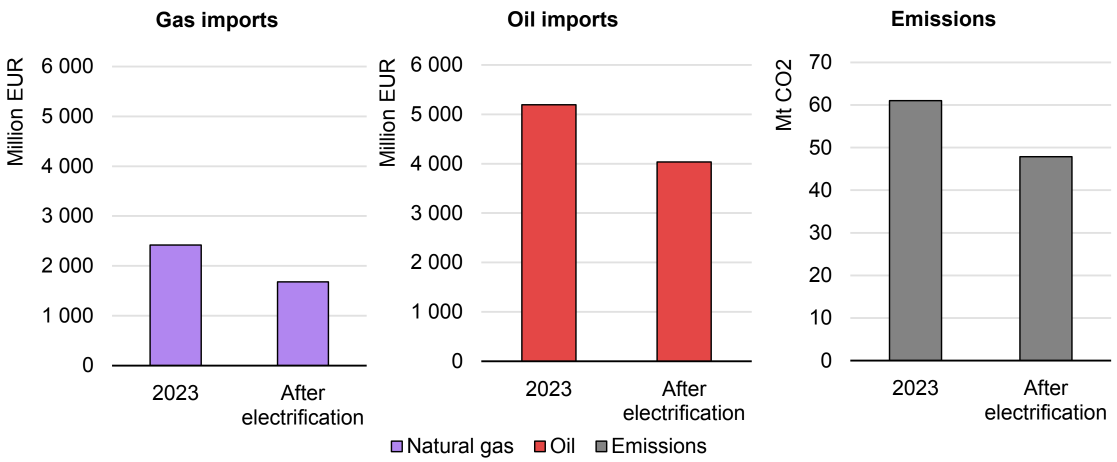
[11] Assuming that the battery electric vehicles included in this demand are replacing internal combustion vehicles; and based on average mileage in Ireland in 2023 and on fuel economy assumptions for similar European countries in 2035.

Heat and road transport electrification can greatly contribute to energy security and decarbonisation

Clearly, if integrated securely into the power system, heat and road transport electrification could reduce Ireland's reliance on fossil fuels significantly, offering the obvious associated energy security and climate benefits. The electrification described above could reduce natural gas demand by 46 PJ/yr, and that of oil and oil derivatives by 144 PJ/yr. Assuming that the resulting electricity demand would be met largely by new renewable generation sources, greenhouse gas emissions could decline by 8 $MtCO_2$/yr from the industry and residential sectors, and by 5 $MtCO_2$/yr from road transport.

At 2023 prices, savings from reduced imports would amount to around EUR 740 million annually for natural gas and around EUR 1 billion for oil imports. However, electrification is still largely more expensive than continued reliance on fossil fuels, so cost is a significant barrier to accelerated deployment.

Potential fossil fuel import and emissions reductions associated with heat and road transport electrification in Ireland



Notes: Savings estimates are based on 2023 LNG price of USD 15/GJ and an oil price of USD 80/barrel, at a currency conversion rate of USD 1 = EUR 0.9248 (2023 average).
Sources: IEA analysis; ECB (2025), Euro reference exchange rates.

Cost-competitiveness of electrification

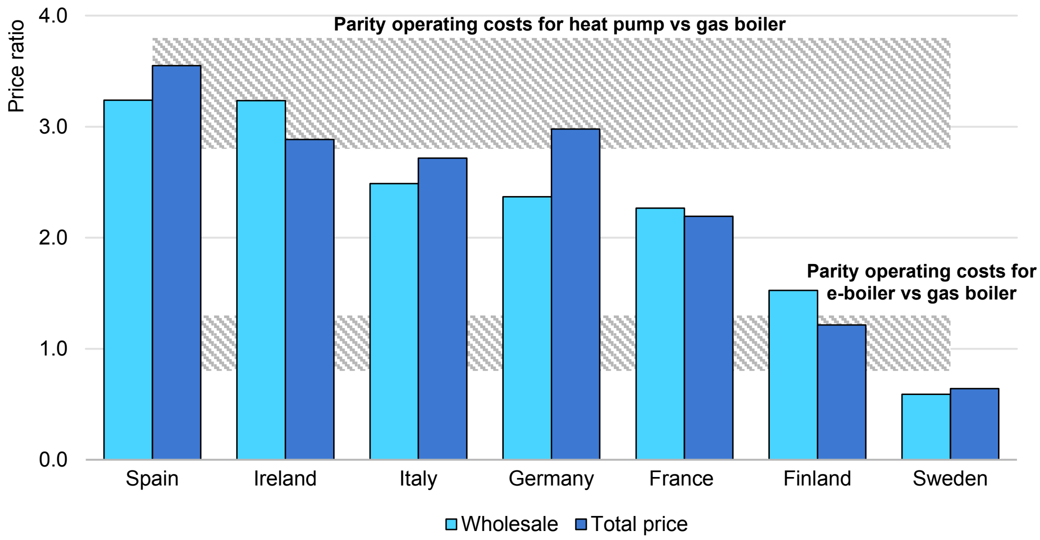
The cost-competitiveness of electric options for heat and transport remains a critical factor in their widescale adoption. Upfront costs for electric heating devices (especially heat pumps) and EVs are typically higher than for fossil fuel-fired boilers and internal combustion engine (ICE) vehicles, but their lower operating costs could offset the difference. While the cost of installing industrial heat pumps for low-temperature processes is high, operating costs are low. However, it is more difficult for high-temperature processes to switch from natural gas given current energy prices, taxes and grid fees, even though thermal energy storage can improve the business case for electric options and enhance system flexibility.

For road transport, purchasing a representative EV model is currently slightly more expensive than a comparable diesel version, but the costs of EVs are expected to fall below those of new ICE vehicles by 2030. Imported used vehicles may be even more affordable for consumers than new models, if buying used is preferable. Beyond costs, non-economic barriers may still hinder faster EV adoption.

The attractiveness of industrial heat pumps depends on a favourable electricity to gas price ratio

The cost of producing heat at industrial scale is generally governed by fuel-related operating expenses, meaning that the attractiveness of industrial heat pumps is largely measured by the electricity-to-fossil-fuel price ratio. In Europe, industrial heat boilers typically burn natural gas, and the figure below shows the price ratios for industrial consumers in selected EU countries in 2024. As a rule of thumb, the electricity to gas price ratio would need to be close to one to make electric boilers attractive against gas boilers. For heat pumps – thanks to their high coefficient of performance – operating costs can break even with a ratio as high as three.

Electricity to natural gas price ratios for industrial users in selected EU countries, 2024



Source: Eurostat (2025), Prices of natural gas and electricity.

In 2024, the wholesale electricity to gas price ratio in Ireland was 3.2, one of the highest in Europe. If distribution costs and taxes are included,[12] the ratio improves slightly to 2.9, but still remains significantly high. One way to make electric heating technology options more attractive is to reduce the ratio between electricity and gas prices, as has been done by other EU countries such as Sweden, to boost industrial decarbonisation.

Heat pumps have significantly higher upfront costs than fossil fuel boilers, partly because of integration expenses, which can represent half of the total investment.[13] The cost-competitiveness of heat pumps therefore depends on whether efficiency gains are sufficiently large to justify the higher investment. Grid connection costs are project-specific, depending on, for example, the extent of work required to connect the site and its distance from the nearest substation. They can be especially high if the connection is large enough to require a transformer upgrade.

Thermal energy storage can lower costs while enhancing system flexibility

While annual average electricity prices are an important indicator of the overall attractiveness of heat electrification, actual electricity prices for industrial consumers can differ significantly depending on contractual arrangements (such as long-term renewable energy power purchase agreements) or time of use. For a consumer exposed to wholesale electricity prices, which fluctuate every hour, the timing of electricity demand has a significant impact on the business case for process heat electrification.

Some industrial processes have inherent operational flexibility (for instance, batch production that can be done when electricity prices are lowest) that allows managers to minimise electricity costs. For inflexible continuous processes, electricity demand can be made flexible either by using an existing gas boiler as a backup energy source during periods of high electricity prices, or by buffering heat supply with affordable thermal energy storage. Thermal energy storage technologies are available in several forms, but storage solutions based on sensible heat storage (such as hot water tanks) are generally characterised by a simple construction and inexpensive materials such as steel and sand/bricks. The storage cost associated with a hot water tank is roughly EUR 10/kWh – an order of magnitude lower than large-scale battery energy storage.

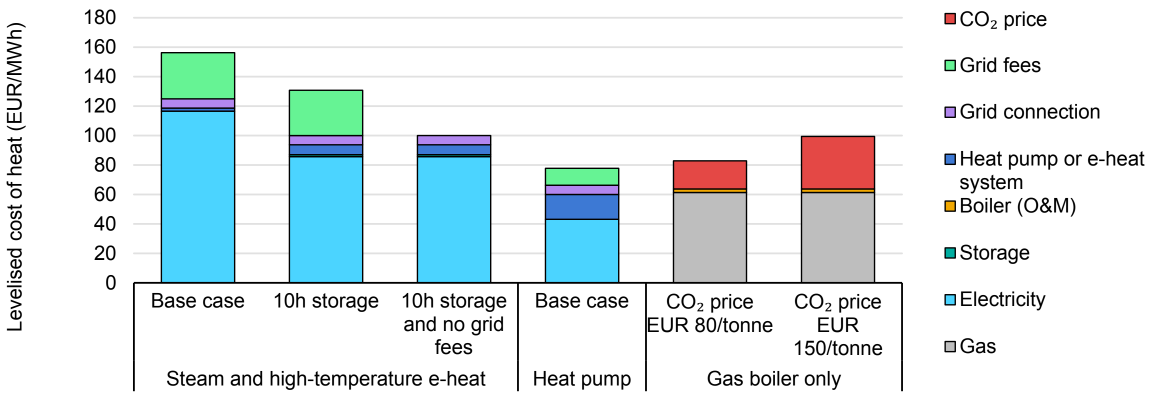
[12] Adding to wholesale prices are network costs, taxes and levies. In 2024 the wholesale price represented 67% (EUR 227/MWh) of the total price, while network costs made up 23% (EUR 79/MWh) and taxes 9% (EUR 31/MWh).
[13] Connection fees can also raise the investment bill, depending on the site's proximity to a high-voltage line, but they generally make up just a small share of total ownership costs under the current tariff scheme.

Based on 2024 hourly electricity prices, the levelised cost of heat (LCOH) of an electrothermal system producing steam could be nearly 12% lower when coupled with five hours of storage, compared to without storage. Extending storage to 10 hours can reduce the LCOH by 16% – beyond which economic gains from additional storage become limited.

Network costs, taxes and levies (and their allocation to end users) affect the economic attractiveness of heat electrification considerably. In 2024, network costs represented 23% (EUR 79/MWh) and taxes 9% (EUR 31/MWh) of the total average electricity price for industrial consumers in Ireland. At 2024 prices, grid costs, taxes and levies on electricity together represent three-quarters of the cost gap between an existing gas-fired boiler and a new electrothermal steam system with storage.

Closing this cost gap in the current price environment would require tripling the current tax rate on gas or introducing a CO_2 price of EUR 150/tonne. However, still considering 2024 wholesale electricity and gas prices, industrial heat pumps can be cost-competitive with gas boilers for low-temperature processes.

Levelised cost of heat from electricity and natural gas under various assumptions in Ireland, 2024



Notes: O&M = operations and maintenance. Assumptions used for this exercise are: process heat demand = 3 MW; electric boiler investment cost = EUR 150 /kW; heat pump investment cost = EUR 1 500/kW; thermal energy storage investment cost = EUR 10/kW; coefficient of performance of the heat pump = 2.7; gas boiler efficiency = 85%; storage losses per hour = 0.08%; maximum storage charge rate = 6 MW; initial grid connection cost = EUR 2.1 million; annual capacity grid fee = EUR 1902/MW; annual consumption grid fee = EUR 31/MWh; annual O&M costs of electric boiler, heat pump and storage = 5% of initial investment cost; annual O&M costs for gas boiler = EUR 2/MWh of heat output; gas price (excl. taxes and levies) = EUR 56.7/MWh (consumption band I3); tax rate on gas (incl. VAT and recoverable taxes and levies) = 20.6%; tax rate on electricity (incl. VAT and recoverable taxes and levies) = 7% (consumption band IE); discount rate = 5%; system lifetime = 20 years. For systems with storage, the model simulates the case of a consumer optimising storage operation and consumption, based on hourly electricity costs, known each day at 2 pm for the following 34-hour period (until the end of the next day).

Sources: EirGrid (2024), Statement of Charges 2024-2025; Eurostat (2025), Natural Gas Price Statistics; ENTSO-E (2025), Transparency Platform; Eurostat (2025), Electricity Price Statistics.

High purchase cost is the main economic barrier to electric vehicle adoption

While the attractiveness of switching from gasoline and diesel vehicles to electric alternatives can be influenced by the extensiveness of supporting infrastructure and customer beliefs, it is largely governed by the cost of EVs. Cost-competitiveness is usually based on the total cost of ownership (TCO), a metric that estimates the total cost of owning a vehicle over a certain period (or per kilometre driven) and can detail separate costs for vehicle purchasing, financing, energy consumption and maintenance, among other expenses. While energy-related expenditures are lower for EVs owing to their superior efficiency, particularly when average trip distance is great, the higher upfront cost (mostly resulting from the cost of the battery) is the key economic obstacle in road transport electrification.

This section analyses the economic attractiveness of passenger car and truck electrification in Ireland. These two segments, which account for the largest shares of energy use in road transport, can make the greatest contribution to energy security because of their high reliance on imported fossil fuels.

Passenger cars

Irish consumers tend to prioritise purchase price, with upfront costs accounting for about 50% or more of the TCO across electric and non-electric models. Other TCO components such as taxes, insurance and financing costs are often calculated relative to the vehicle's purchase price, further impacting the cost-competitiveness of battery electric vehicles (BEVs).

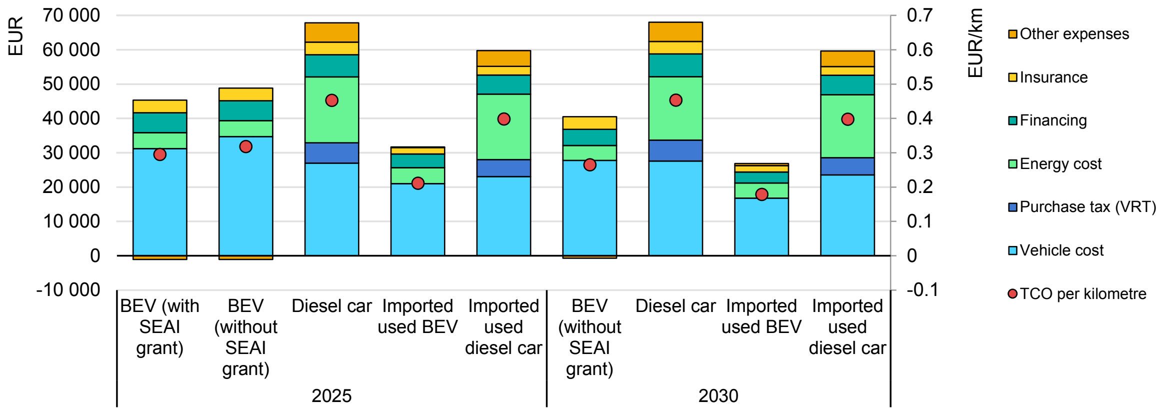
In Ireland, policy is playing a key role in closing the gap in vehicle purchasing costs. For example, in the SUV segment, which accounted for 55% of new car sales in Ireland in 2024, the upfront cost of a representative small battery electric SUV model is around EUR 31 000 after VAT exemptions (equivalent to 23% of the vehicle's purchase cost) and SEAI grants of EUR 3 500. A comparable diesel model has an upfront cost of around EUR 33 000, including purchase taxes.

Without SEAI grants, the BEV price would exceed the comparable diesel vehicle's combined vehicle and purchase tax cost, demonstrating that without grants, non-electric vehicles would have a significant upfront cost advantage. Thus, some government support is clearly needed to encourage continued BEV adoption.

However, even without purchase subsidies, BEVs are set to become more cost-competitive towards 2030 as battery costs fall, while diesel vehicle prices may remain much the same. The cost of a representative battery electric SUV model sold in Ireland today is projected to decline to EUR 27 000, while the representative diesel model's cost rises to EUR 34 000. Similar trends are anticipated in Ireland's considerable imported used car market, which accounted for 35% of newly registered vehicles in 2024.

Lower operating costs, particularly for fuel and maintenance, further improve the TCO competitiveness of BEVs over diesel vehicles. Depending on the period and market segment (new cars or imported used ones), BEVs are shown to have a lower TCO than diesel vehicles – 55% lower for new cars and 33% less for used imported ones.

Representative total 10-year cost of ownership of a battery electric vs diesel car, 2025 and 2030



Notes: BEV = battery electric vehicle. TCO = total cost of ownership. TCO estimates are based on the C-segment (small-sized) SUV category commonly used in Ireland. The Volkswagen ID.4 (BEV) was selected for both new and imported used vehicles, while the Hyundai Tucson and Volkswagen Tiguan represent diesel vehicles, reflecting data availability. Vehicle costs include the vehicle price minus SEAI grants for newly registered BEVs (unless otherwise stated). Purchase taxes refer to vehicle registration taxes (VRT), calculated based on the vehicle's CO_2 emission level. All input data, including vehicle costs, fuel prices and fuel economy, are based on 2025 conditions. Annual average mileage = 15 000 km; EV tariff (day) = EUR 0.22/kWh with a 10% share of day charging; EV tariff (night) = EUR 0.07/kWh with a 70% share of night charging; EV tariff (public, fast) = EUR 0.57/kWh with a 20% of share of public charging; diesel fuel cost = EUR 1.65/L. Insurance and maintenance cost assumptions are based on the IEA Global EV Outlook 2024.

Sources: IEA (2024), Global EV Outlook 2024; Irish Revenue (2025), Calculating Vehicle Registration Tax (VRT); Switcher.ie (2025), Electric Car Charging in Ireland; SEAI (2025), A Year Driving Electric; AA Ireland (2025), Irish Fuel Prices; Society of the Irish Motor Industry (2025), Motor Statistics.

Nevertheless, several barriers continue to limit BEV adoption. Recent surveys indicate that many consumers focus on upfront cost, without perhaps taking full account of the SEAI grants and VRT exemptions in their decision-making. This may contribute to the continued perception that EVs are expensive, despite their potential long-term cost advantages and the incentives currently available. Access to the used car market also influences customer decisions: while used diesel vehicles are widely available across a broad range of models and price points, making them more affordable, used EV options are limited.

Additionally, charging infrastructure requirements (discussed at the end of this chapter) can make consumers hesitant to purchase BEVs (for instance in rural communities), even when the vehicles are affordable. Survey respondents also indicated that range anxiety remains a barrier. This can particularly impact buyers who lack access to home charging or frequently undertake long-distance trips.

Addressing these obstacles through stable policy support for BEVs will therefore be vital to fully realise the potential of their adoption in Ireland's passenger car market.

Trucks

Unlike passenger cars, for which citizens may often prioritise upfront costs, TCO is the primary driver of electric truck adoption. Thanks to their high annual mileage and efficiency advantages, battery electric trucks, which are about 55% more efficient than diesel models, offer potential cost savings depending on energy prices, truck and infrastructure costs, and other factors such as maintenance and taxation.

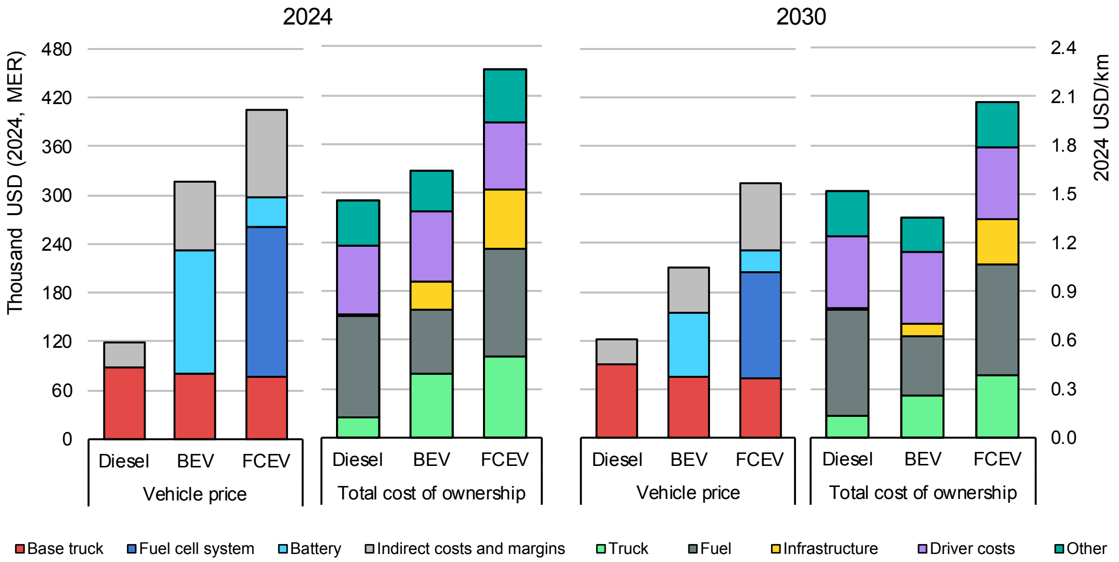
Ireland's geography also plays a role, with over 90% of haulage journeys taking place within the island. Its size – about 600 km north to south – generally implies shorter routes and enables much charging to be done overnight at depots, minimising reliance on public infrastructure and reducing costs. Over 600 km of range can be added with just a 100-kW charger.[14]

Battery electric trucks are expected to break even on a TCO basis in the European Union without subsidies between 2024 and 2030 for daily distances of up to 500 km, creating a strong financial impetus for hauliers to transition to electric fleets. This commercial viability could significantly accelerate sales among hauliers and improve access to financing, which tends to be more readily available for commercial fleets than for households. However, half of Irish haulage businesses operate fleets of fewer than 10 trucks, making the investment costs more difficult to absorb. Targeted policy support will be crucial to facilitate fleet electrification among smaller operators who may struggle with upfront financial barriers.

As energy costs are estimated to have accounted for around 25% of the TCO in the European Union in 2024, the cost-competitiveness of electric trucks is highly sensitive to electricity prices (even more than electric passenger cars). Potential drops in energy costs, as well as incentives that reduce financing or vehicle purchase costs, could encourage businesses to choose electric truck alternatives.

[14] Assuming 10 hours overnight, and electricity consumption of 160 kWh per 100 km.

Estimated vehicle price, and total cost of ownership of diesel, battery electric and hydrogen fuel cell heavy-duty trucks in the European Union, 2024 and 2030



Notes: BEV = battery electric vehicle. FCEV = fuel cell electric vehicle. MER = market exchange rate. Please see the IEA Global EV Outlook 2025 annexes for a complete list of assumptions.
Source: IEA (2025), Global EV Outlook 2025.

The importance of grid infrastructure

Delivering the energy security benefits of electrification will depend not only on the availability of low-emission electricity supplies and end-use technologies, but also on the capacity and reliability of the electricity grid to accommodate increasing power demand from electrification, new housing developments, industry and services. As heating and road transport transition away from direct fossil fuel use, electricity demand is set to rise significantly, both in total volume and in geographic and temporal concentration.

Without timely and targeted grid infrastructure expansion, this new demand could strain existing assets, hinder electrification progress and introduce new system vulnerability risks. Strengthening the transmission and distribution networks is therefore a strategic investment in national energy security, ensuring the system can reliably deliver affordable clean energy where and when it is needed.

A modern, flexible grid will also be needed to integrate higher shares of VRE, which can displace imported fossil fuels and reduce Ireland's exposure to international fuel market volatility. While electrifying heat and road transport can make it possible to align demand with variable renewable generation, this will require grid infrastructure that can accommodate both the decentralised nature of new loads – such as residential heat pumps and EV chargers – and the dynamic balancing needs of a more electrified energy system.

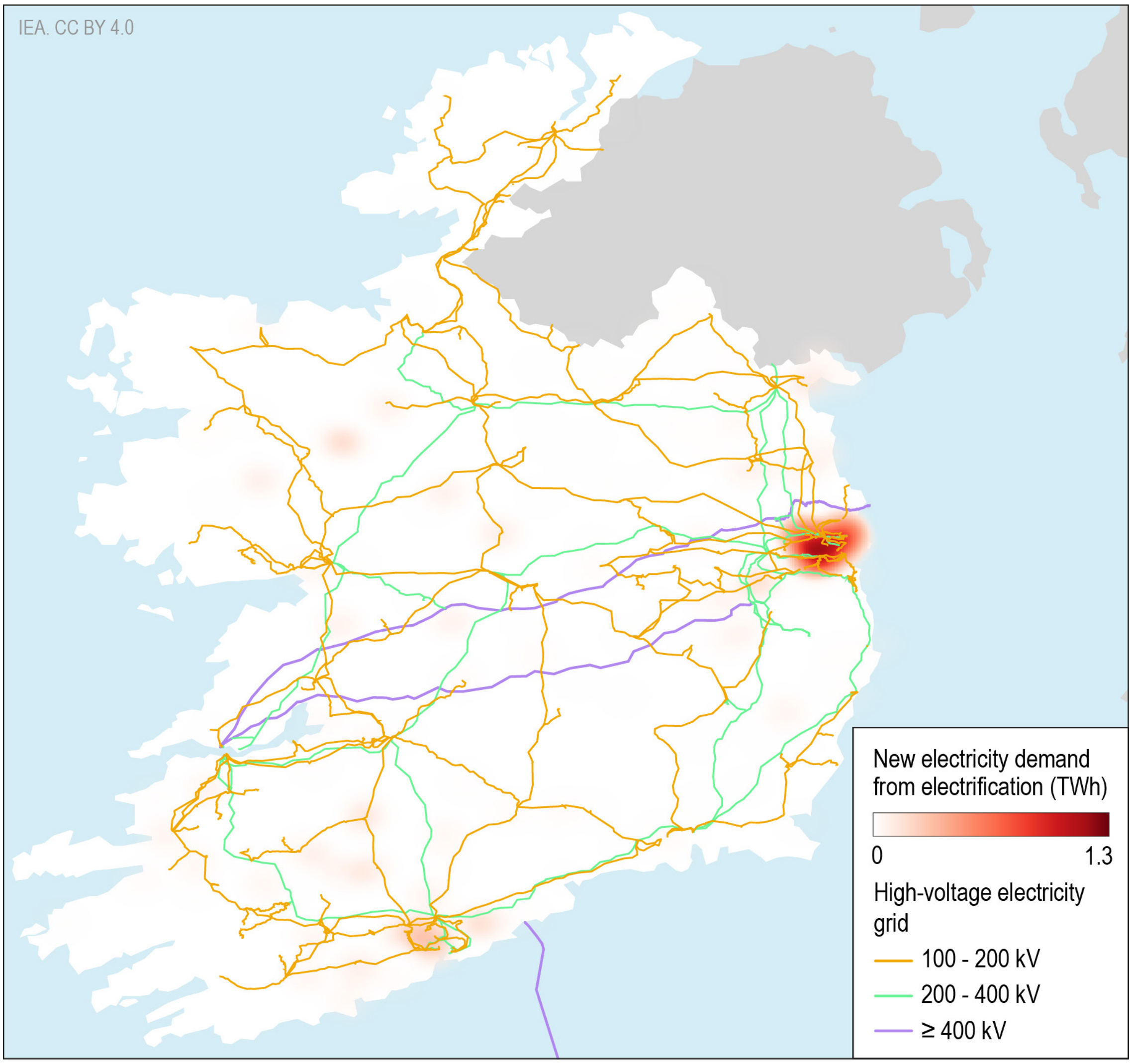
A robust power grid is therefore critical to enable electrification, as grid constraints can lead to longer delays and higher costs. Proactively assessing where new electricity demand from heat and transport is likely to emerge can help authorities prioritise grid planning. The next section's geospatial analysis can serve to inform these priorities and reduce the risk of grid constraints creating bottlenecks.

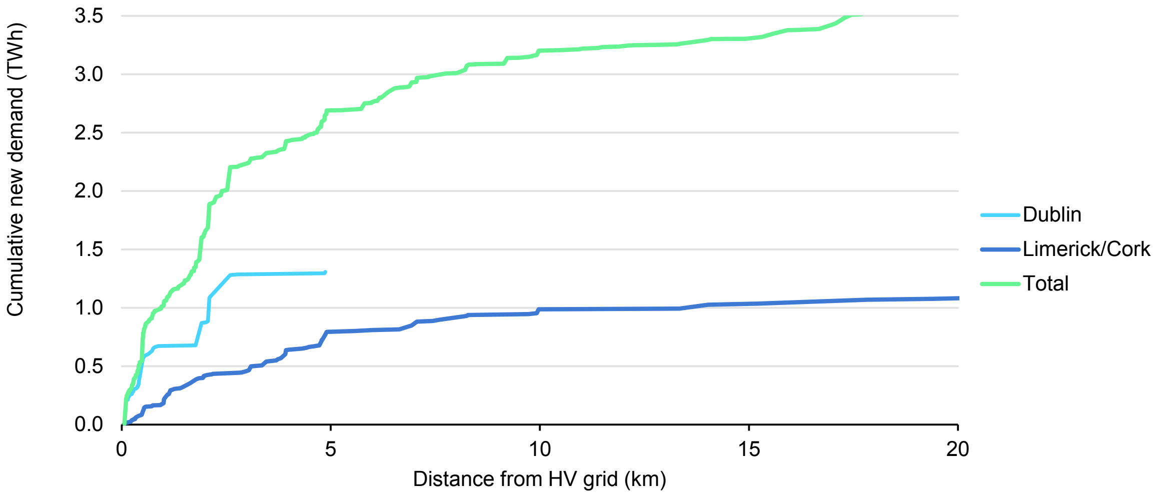
Mapping heat and road transport electrification is key to identify necessary grid infrastructure upgrades

Additional power demand from industrial heat electrification is expected to emerge from the locations where most light industries are concentrated, around Dublin and in the Cork-Limerick area in the South-West. New electricity demand in the Dublin area would be very concentrated, with 70% of new consumption less than 5 km away from the existing high-voltage grid.

In the South-West, however, new electricity demand would be more dispersed. Plus, many small plants could connect at the distribution level, where grid access is widely available. However, grid expansion would still be needed to accommodate this new, inflexible electricity demand to avoid congestion. This is the case for Cork, Ireland's fastest-growing city: its population increased more than 6% between 2016 and 2022, and it is targeting 60% growth by 2050. While the area's additional power demand would strain the existing 220-kV lines serving the city, industries in the region are well positioned to take advantage of the 700-MW Celtic Interconnector planned to begin operations in 2027.

Concentrations of potential new electricity demand from light industry (top) and proximity to existing high-voltage power grid (bottom) in Ireland



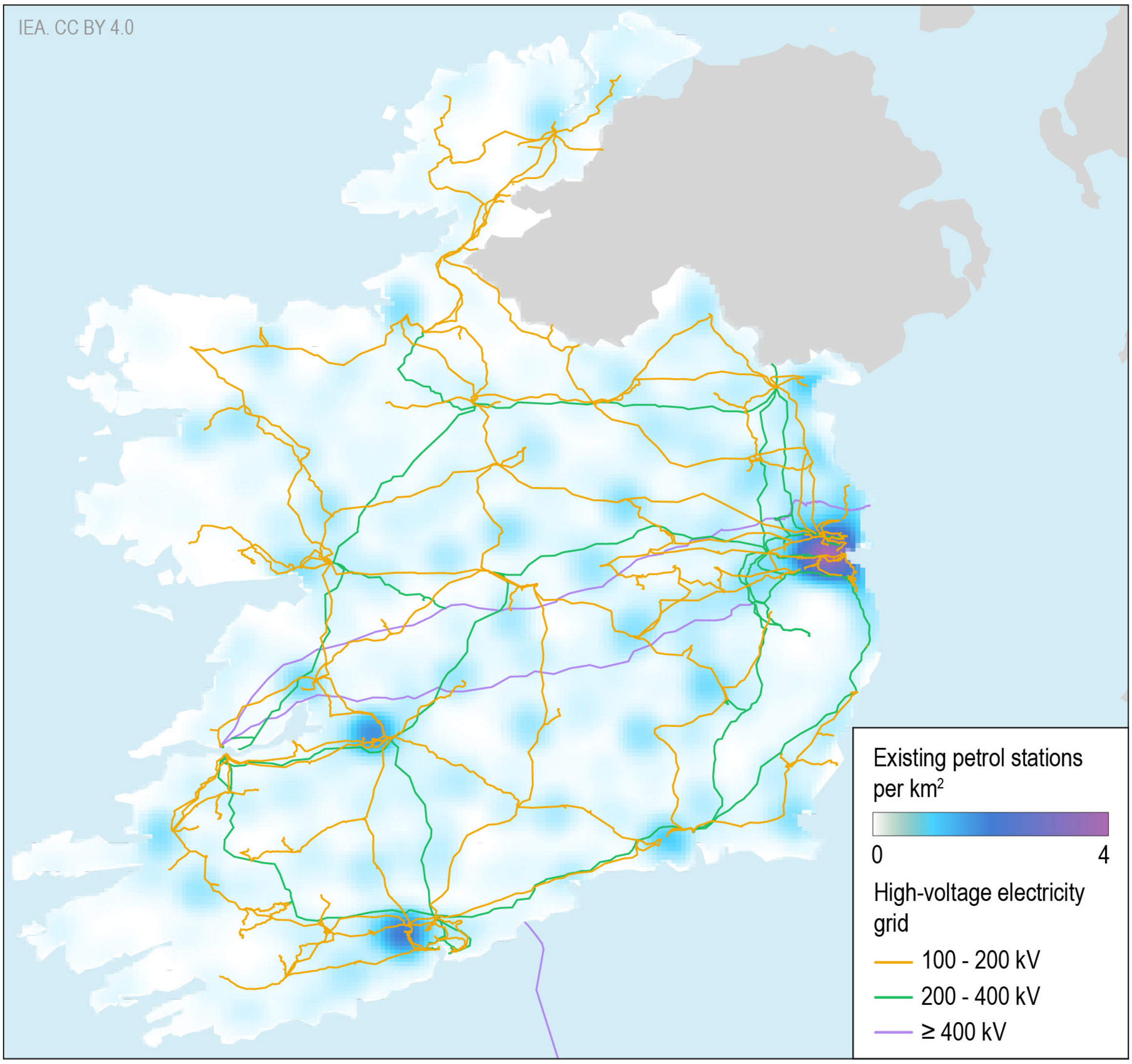


Note: Light industry refers to food and beverages; wood and wood products, textiles; paper; transport equipment; chemicals; and machinery.
Source: IEA analysis using data from Open Street Map.

Other sources of new demand associated with EVs are more widespread than for light industry, so inadequate grid infrastructure could weaken both electricity security and progress on electrification. In a recent survey, just 20% of non-EV-owning respondents cited no/limited access to home charging as a reason for not buying an EV, which suggests overall high levels of access to home charging in Ireland. One-third of potential EV buyers indicated that lower-cost overnight charging was a factor in their decision. Together, these responses imply that a substantial share of private EV charging will be done at home at night, creating both opportunities and challenges for the grid.

These challenges can be particularly acute in rural areas with weak grids, where it will be complicated to ensure that grid capacity expansion/renovation does not create significant bottlenecks that interfere with the deployment of EV charging infrastructure, requiring the strongest co-ordination efforts. This is particularly important because charging infrastructure can be connected at a variety of segments of the power grid, ranging from low-voltage distribution for private home chargers to medium- and high-voltage lines for fast-charging stations, especially if they are expected to meet demand from electric trucks.

Concentration of petrol stations relative to high-voltage power grids in Ireland, 2025

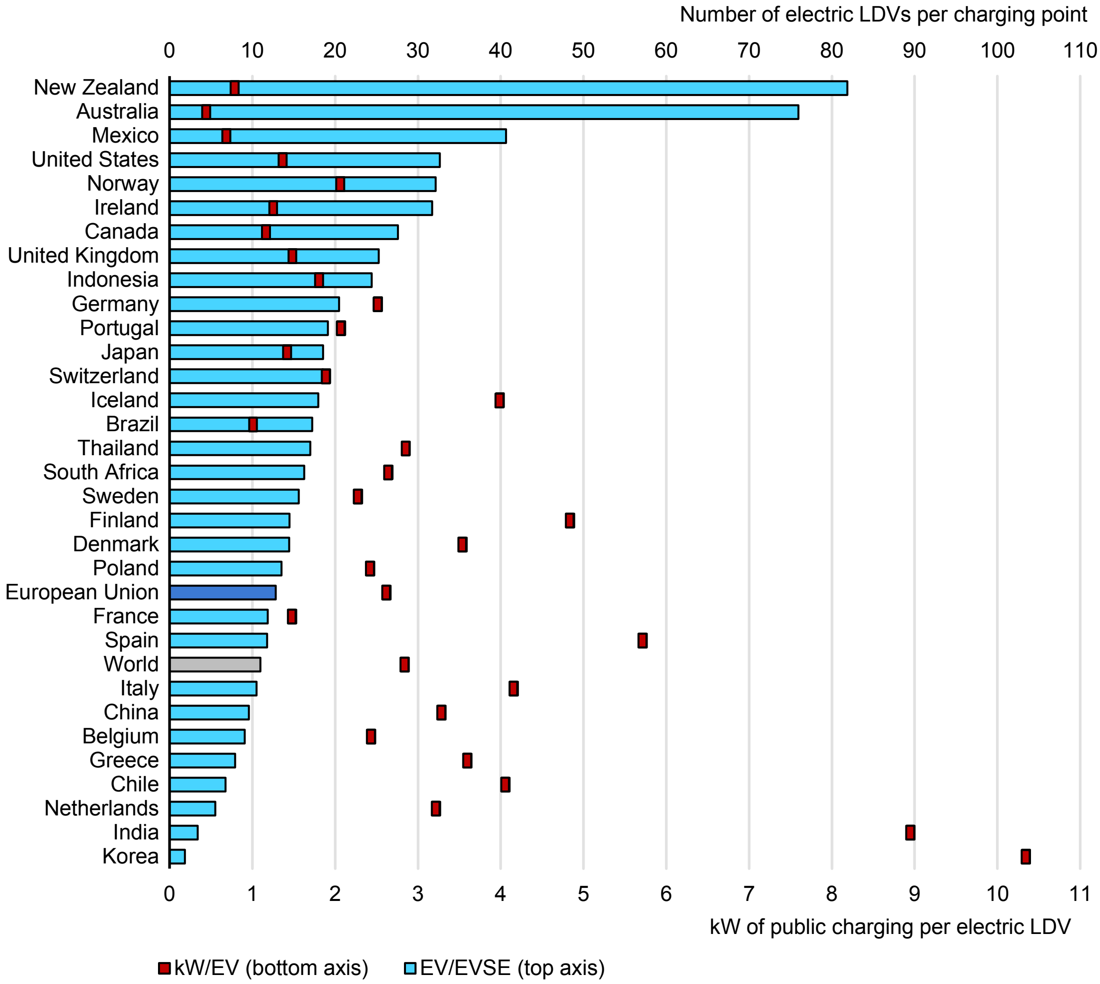


Source: IEA analysis using data from Open Street Map.

In co-ordination with grid development, it is critical to ensure sufficient availability of EV charging infrastructure. As indicated by over 20% of survey respondents, expanding public EV charging infrastructure will be vital to encourage uptake, especially initially. To meet Ireland's transport electrification targets, charging infrastructure needs to be expanded significantly. In 2024, the country had 1.2 kW of public charging capacity for every light-duty electric vehicle (slightly below the target laid out in the Alternative Fuels Infrastructure Regulation).

Based on Ireland's Climate Action Plan and the Alternative Fuels Infrastructure Regulation, ESB Networks expects public charging capacity to increase from about 50 MW in 2023 to 800 MW in 2030, and to nearly 1 700 MW in 2040. One of the measures ESB Networks is implementing to enable this growth is to increase voltage in the medium-voltage power grid from 10 kV to 20 kV to reduce losses and quadruple capacity in that grid.

Electric light-duty vehicles per public charging point, and kilowatts per vehicle, 2024



Notes: EV = electric vehicle. EVSE = electric vehicle supply equipment. LDV = light-duty vehicle. Kilowatts per EV are estimated assuming 15 kW for slow chargers, 50 kW for fast and 150 kW for ultra-fast. For countries in Europe, average power per EVSE was used for each power group (slow: lower than 22 kW; fast: 22-150 kW; ultra-fast: higher than 150 kW) and multiplied by the reported charger stock. Official national statistics, which rely on more granular data, might differ from these values.

Source: IEA (2025), Global EV Outlook 2025 based on BNEF, EV Volumes, European Alternative Fuels Observatory and Eco Movement, US Alternative Fuels Data Center.

Meanwhile, the Irish government has released policy-level plans to deliver necessary charging infrastructure for all vehicle segments, including the National Road Network EV Charging Plan 2024-2030 and the EV Infrastructure Strategy 2022-2025. These policies address the need to expand charging infrastructure to enable higher EV uptake.

Impact of Ireland's expected housing buildout on electricity demand and infrastructure needs

Ireland's housing stock is set to expand significantly in upcoming years, in line with government aims to address the current home shortage. The Programme for Government 2025 - Securing Ireland's Future introduces a new national housing plan to ramp up construction capacity, with the goal of building over 300 000 new homes by the end of 2030 to meet the current and future demand specified in the revised housing targets.

Adding to new demand from heat and transport electrification, the buildout of new homes will lead to a corresponding rise in power use, in terms of both total consumption and peak load. In particular, the transition from fossil fuel heating systems to electric heat pumps – now mandated in new builds – and rising EV uptake mean that average electricity demand per household will be notably higher than in the past.

These growth expectations put additional pressure on electricity networks, especially in urban and suburban areas. Accommodating a large number of new connections – while also supporting higher per-customer loads – will require the country to expand its substation capacity, reinforce medium- and low-voltage lines, integrate more smart grid functionalities, and improve local network resilience. It is therefore planning to construct 27 new critical 110-Kv substations to strengthen power network resilience, capacity and flexibility while enabling wider electrification and renewable energy integration.

Given the cumulative effects of new housing combined with heating and transport electrification, it will be challenging for Ireland to plan and deliver timely grid infrastructure upgrades. This underscores the importance of aligning housing development strategies with energy system planning to ensure that electricity infrastructure evolves in step with national security, decarbonisation and housing delivery goals.

Chapter 3. Meeting growing electricity demand to 2035

This chapter investigates the power system implications of energy system transformation in Ireland to 2035 as the country's electrification potential intersects with its decarbonisation targets and fundamental changes to electricity generation. Model-based analysis examines the risks and opportunities of this transformation, using 2030 and 2035 as reference years. It characterises the 2030s as a period of medium-term uncertainty between the current, well-defined policy landscape and the less-detailed long-term target framework after 2040. Our cross-sectoral analysis for the 2030s is designed to help authorities establish a route to achieve Ireland's long-term policy priorities.

This chapter presents the IEA Adapted Transition Pathway scenario, adapted from EirGrid's existing scenarios in the All-Island Adequacy Assessment and Tomorrow's Energy Scenarios. The latter aims to achieve most of Ireland's emissions and renewable capacity targets, using a power system model with economic dispatch and unit commitment. This chapter explains the methodology and reasoning behind the scenario assumptions, describes the main trends and discusses its energy security implications.

Furthermore, to highlight risks and vulnerabilities, this chapter examines Ireland's future power system from the perspectives of resource adequacy (the ability of available supply to meet demand) and flexibility, investigating the electricity security implications of these uncertainties in 2030 and 2035 through a range of sensitivity analyses. However, it does not seek to replicate or replace national and European resource adequacy studies. It avoids analysing detailed outage patterns, focusing instead on the broader energy security implications of supply and demand uncertainties.

Model-based analysis explores Irish power system evolution to 2035 and associated security risks

The Government of Ireland has confirmed it will focus on implementing existing energy system targets, balancing them with broader policy goals such as affordability and industrial strategy. To investigate the country's power sector transformation, the Adapted Transition Pathway scenario, developed in collaboration with EirGrid, provides a pathway for power system evolution to 2035. It combines credible projections of capacity development to 2030 with the achievement of longer-term electrification and renewable energy targets in 2035.

It also explores security risks that fall beyond the horizon of existing near-term studies but are still near enough to warrant more detail than longer-term studies provide.

While Ireland's energy and climate policy framework to 2030 is well defined, guiding capacity targets and sectoral emission ceilings have yet to be determined for 2035. The Adapted Transition Pathway capacity and demand assumptions for 2030 are therefore based on the All-Island Resource Adequacy Assessment, and assumptions for 2035 are drawn from the Self-Sustaining scenario of Tomorrow's Energy Scenarios. These scenario assumptions are not prescriptive forecasts but instead reflect greater confidence regarding 2030 outcomes and the potential for policy choices to accelerate delivery to 2035.

The IEA developed a power system model with hourly unit commitment and economic dispatch to explore Ireland's energy security challenges and opportunities in implementing its plans in the coming decade. Sensitivity analyses tested how key uncertainties and risks could affect the Irish power system in 2030 and 2035. The model replicates the Single Electricity Market (SEM), simulating power plant dispatch optimised for least cost while including expected system operating constraints, with interconnections to Great Britain and France.

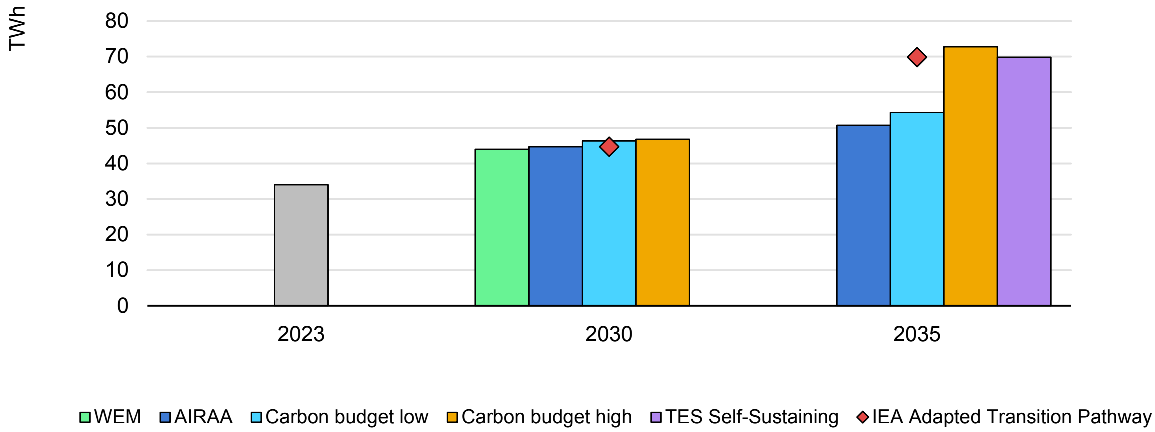
Results are for Ireland only, excluding Northern Ireland unless otherwise specified. The model accounts for flows from Great Britain and France to third countries but does not include them in its optimisation, while out-of-market capacity (such as temporary emergency generation) is assumed to be phased out. Production cost models replicate market fundamentals but do not always capture the full effects of unpredictable generator behaviour during scarcity events. The modelling annex provides a detailed description of the model and its assumptions.

Demand growth

Rapid demand growth is a defining characteristic of Ireland's electricity sector in the next decade. Projections show that electricity demand grows similarly across sources to 2030 but diverges towards 2035, indicating uncertainties regarding pace and extent, and associated system planning and security challenges.

How much of this potential growth is realised – and how quickly – depends on the complex interplay of economic growth, population growth, policy and price signals for electrification – and the power system's ability to absorb new electricity demand. These competing factors influence decisions by both individual consumers and businesses and will determine the flexibility of new demand. Stronger uncertainty for 2035 means greater opportunities to steer outcomes with policy action in the intervening period.

Total annual electricity demand in Ireland from various sources, 2023, 2030 and 2035



Notes: WEM = With Existing Measures (from SEAI National Energy Projections 2024 scenarios). AIRAA = All-Island Resource Adequacy Assessment (2035 AIRAA value extrapolated from 2034 data). TES = Tomorrow's Energy Scenarios. Carbon budget low is the 350 Mt-LED scenario. Carbon budget high is the 300 Mt-WEM scenario.

Sources: SEAI (2024), National Energy Projections 2024; EirGrid and SONI (2025), All-Island Resource Adequacy Assessment 2025-2034; EirGrid (2023), Tomorrow's Energy Scenarios 2023.

Data centres drive demand growth to 2035 in the Adapted Transition Pathway

Electricity demand from data centres has grown strongly in recent years and they are widely expected to propel power consumption growth in Ireland over the next decade. From 6.9 TWh in 2024, their absolute demand is projected to double by 2035 in the Adapted Transition Pathway, as total demand also doubles from 2023 to 2035, reaching more than 65 TWh.

Contracted data centre capacity is anticipated to consume at least 30% of the country's power supply in 2030, and by 2035 it is the sector with the highest electricity consumption in the Adapted Transition Pathway. Efficiency improvements in cooling, hardware and configuration are expected to reduce data centre electricity consumption intensity, but the effects remain uncertain. This accelerated growth poses system planning and security challenges.

Although data centres are a key contributor to economic growth in Ireland, rapidly rising power demand must be accommodated in a manner that serves – rather than complicates – both system security and wider societal and economic needs. Requests for new data centre connections have to be submitted a few years in advance, giving some indication of likely electricity demand growth from large data centres to 2030.

However, even this length of notice can make long-term network planning difficult for system operators whose network development plans are regulated in multiannual price review periods. Beyond 2030, commercial decisions to build new data centres are driven by industrial policy, the evolving economic environment and global technology trends, leaving a significant margin of uncertainty around the magnitude of electricity growth in this subsector to 2035.

Recognising the challenges of rapid data centre demand growth, the CRU has proposed that new large energy users build generation and/or storage capacity equivalent to their site's peak demand as a binding precondition for grid connection. According to the CRU, its goal is to ensure that dispatchable capacity keeps pace with demand growth (assuaging adequacy concerns) and to limit the exposure of Irish consumers to the high cost of new generation capacity. This proposal reflects the broader policy challenges involved in managing electricity demand growth while balancing digitalisation, economic development and security objectives.

The residential and transport demand growth trajectory is uncertain in the medium term

As discussed in Chapter 1, the government's intention to accelerate housing construction is a strong power demand growth driver to 2030. While such policies as the planned EU-wide moratorium on new internal combustion engine vehicles give some insight into long-term power demand growth from transport electrification, the trajectory to 2035 is more uncertain than for data centres.

New data centre loads entail fewer, more centralised, more commercially driven decisions and are signposted by public planning approvals and grid connection requests, allowing authorities and market participants to plan proactively. In contrast, a similar demand increase from switching to electric transport and heat (particularly residential) rests on a larger number of decisions by individuals, involving less predictable personal preferences.

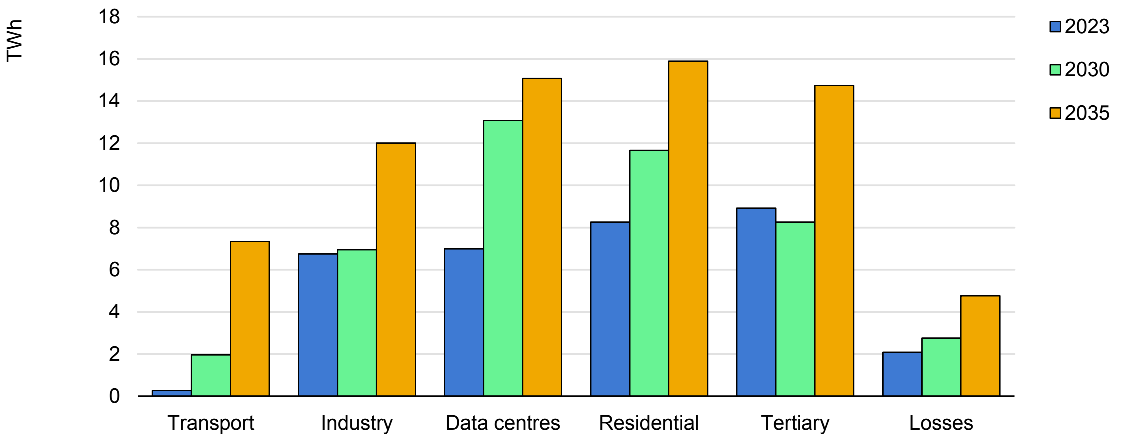
Ireland's high retail electricity prices demonstrate that economic signals for electrification through consumer choice remain weak. Low current electrification levels in residential heat and transport make it difficult to gauge the real-world effects of each additional unit on Ireland's electricity system, even if some of the underlying dynamics of heat pumps and EV demand are known. How, when and where supporting infrastructure is delivered is a greater determinant of electricity demand growth in these sectors.

Demand growth in these sectors will become clearer towards 2035 as additional efforts are made to achieve the country's ambitious heat pump and EV deployment targets. In the meantime, however, uncertainty about load growth entails risks of over- or under-investment in capacity and makes electricity system planning more difficult.

For industrial electrification, streamlined and predictable connection processes for industrial consumers can reduce the barriers of high cost and lengthy grid connection upgrades. Redoubling efforts to establish a reasonable and reliable pathway to meet heat and transport electrification targets will benefit power system planning, wider infrastructure deployment and investment certainty.

In the Adapted Transition Pathway, power demand from heat pumps and EV adoption is projected to increase from less than 5% of annual electricity demand in 2023 to around 20% in 2035, while industrial demand increases only modestly to 2030 because electrification measures take hold in the 2030s.

Annual electricity demand by sector in Ireland in the IEA Adapted Transition Pathway, 2023, 2030 and 2035



Notes: EVs are included in transport; heat pumps are included in industry and residential. Values for 2030 and 2035 are based on the Adapted Transition Pathway.

Supply outlook

Renewable energy is set to dominate Ireland's electricity generation mix in 2030-2035

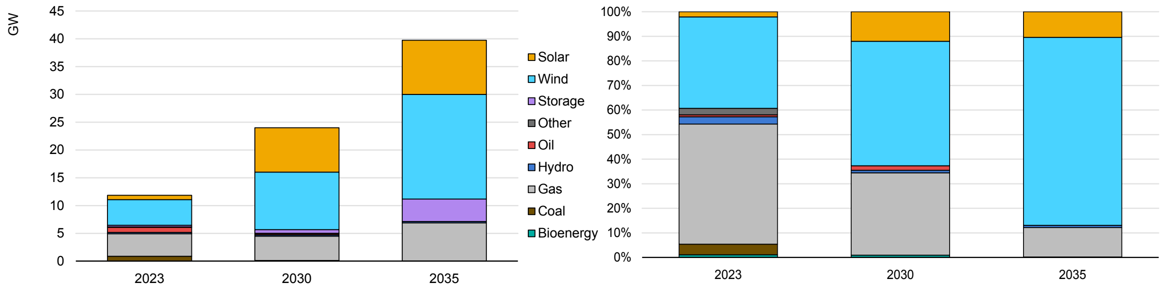
By 2035, renewable energy sources are projected to supply most of Ireland's electricity, with wind providing over 70%, reaching 88% renewable energy sources-based electricity (RES-E) in the Adapted Transition Pathway. The country would accomplish this by building on its successful onshore wind deployment, expanding it from 5 GW to approximately 9 GW by 2030 in the Adapted Transition Pathway.

Reflecting best-case deployment, this expansion would exceed the IEA 2024 Accelerated Case forecast for Ireland by 900 MW. Offshore wind capacity grows from 25 MW in 2025 to 1.3 GW in 2030, as the targeted 5 GW of offshore wind under construction proves challenging to achieve by 2030. Solar PV increases from under 1 GW in 2023 to meet the 8 GW deployment target by 2030, with a strong business case for both utility-scale and rooftop deployment overcoming concerns about Ireland's modest solar yields. This ambitious deployment would result in 18.3 GW of wind and solar capacity – 3.7 GW short of the combined target for 2030.

The 2035 supply mix is based on Tomorrow's Energy Scenarios' Self-Sustaining scenario, with sustained capacity deployment reaching 10.8 GW of onshore wind in 2035 and 8 GW of offshore wind. While delayed offshore wind expansion before 2030 makes it harder to meet the 2035 capacity, the ten-year margin allows more time to effectuate positive 2035 outcomes.

Although generation from natural gas falls to around 10% of total electricity generated in 2035, it still is an important provider of spinning reserves and production during low renewable energy periods. The ambitious 2035 scenario assumes that 1 GW of capacity from low-carbon fuels provides dispatchable low-carbon energy. Unproven technologies such as hydrogen or CCS would require revenue support mechanisms to deploy at scale. As it is unclear how costs will decline for technologies at low readiness levels and to what extent certain technologies, fuels and materials will be available, this report does not recommend a single capacity pathway or particular balance of low-carbon thermal and other forms of energy storage.

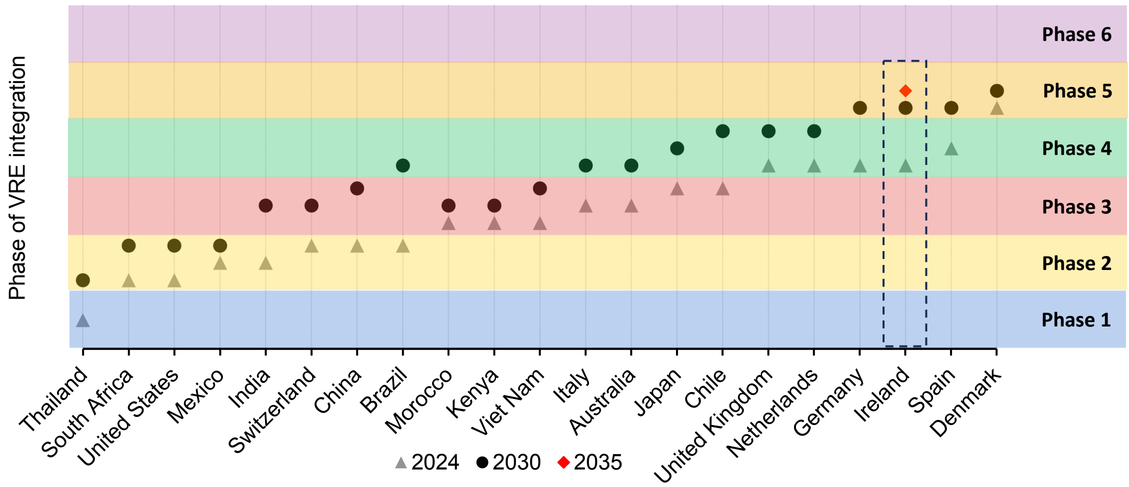
Installed generation capacity by source (left) and proportions of total annual generation (right) in Ireland, 2023 (historical), and IEA Adapted Transition Pathway, 2030-2035



Notes: Coal includes peat. Gas includes low-carbon fuels in 2035. Generation capacity is a model input assumption and generation is a model output.

The scenario modelling shows that realising its variable renewable energy (VRE) capacity ambitions in 2035 places Ireland in Phase 5 of the IEA Phases of VRE Integration Framework. In Phase 5, advanced VRE integration challenges become more prevalent, for example managing electricity supply almost exclusively from VRE, securing longer-duration flexibility and maintaining system stability.

Phases of variable renewable energy integration in selected countries, 2024, 2030, and 2035



Offshore wind deployment is not on track to meet the 2030 capacity target

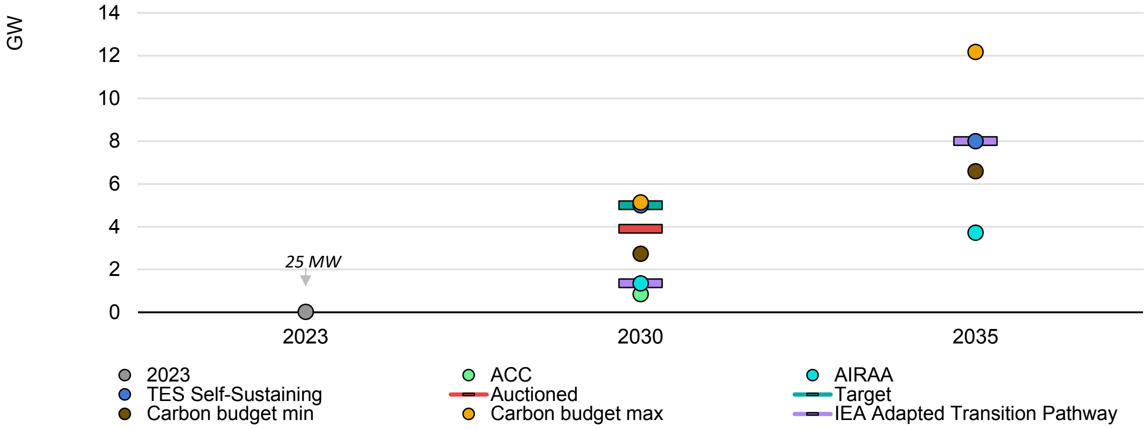
In contrast to the successful growth of onshore wind, the offshore wind trajectory to Ireland's 2030 target of at least 5 GW of installed capacity is steep, with the Adapted Transition Pathway reaching 1.3 GW.

Offshore wind is more exposed to macroeconomic risks than onshore wind or solar PV because it is more capital-intensive and entails longer lead times. Furthermore, the energy crisis, inflation, higher interest rates and an uncertain global trade outlook have made the global environment more challenging for offshore wind deployment. Developers have adapted, however, and continue to bid into subsidy auctions around the world, demonstrating that these issues are not insurmountable.

Ireland is also taking steps to improve conditions for offshore wind deployment. For instance, it is advancing its plan-led system to accelerate the designation of maritime areas for offshore renewable energy and is derisking investment by undertaking geophysical data surveys on the proposed zones. The IEA previously identified Ireland's unpredictable and lengthy planning and consenting processes as hurdles to offshore wind development. Making these processes shorter and more certain can send a strong signal for a robust deployment pipeline in the 2030s, helping the country advance towards its 2040 ambition of 20 GW of offshore wind capacity. While recent legislative changes and progress in spatial planning are welcome developments, their effectiveness in driving renewable energy development – particularly by reducing lengthy judicial reviews and planning appeals – remains to be seen.

Starting from an installed capacity base of 25 MW, Ireland's successful first auction awarded 3 GW of capacity in 2023, with a further 900 MW scheduled for auction in 2025. However, it is uncertain how much of this capacity will come online by 2030, as 450 MW of contracted capacity has dropped out. Not meeting the ambitious 2035 capacity assumptions (which would require rapidly accelerated and sustained buildout to achieve) would delay reductions in Ireland's gas-fired power generation and emissions. This would prolong its exposure to the energy supply security, affordability and decarbonisation risks of greater gas dependence.

Offshore wind capacity assumptions by source in Ireland, 2023 (historical), 2030 and 2035 (various projections)



Notes: ACC = Accelerated Case (from IEA Renewables 2024 forecasts). AIRAA = All-Island Resource Adequacy Assessment (2025). TES = Tomorrow's Energy Scenarios. "Auctioned" is the total allocated in Renewable Electricity Support Scheme auctions up to 2024. "Target" is Ireland's 2030 target for offshore wind capacity. "Carbon budget max" and "min" are the highest and lowest offshore wind capacity assumptions in the 2024 carbon budget modelling by the Energy Policy and Modelling Group.

Gas consumption for electricity generation falls as gas becomes a complement to VRE sources

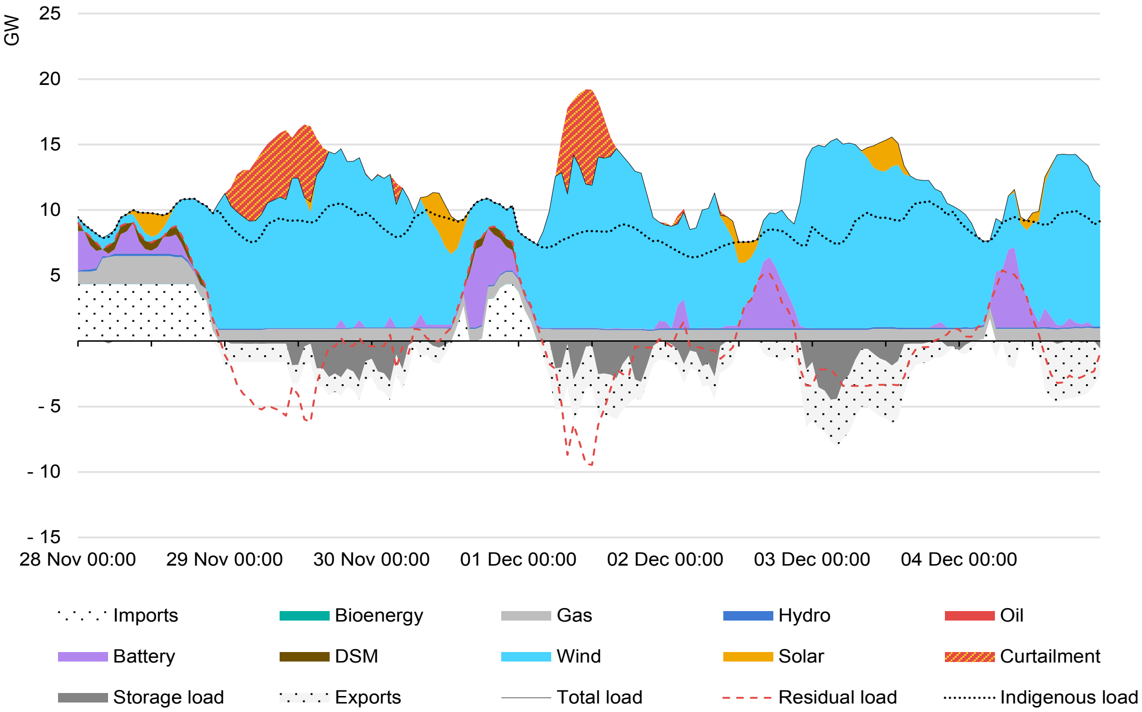
In the Adapted Transition Pathway results, the share of fossil-based generation falls from almost 50% in 2023 to around 30% in 2030 and less than 10% in 2035 as VRE capacity, storage capabilities and interconnections expand. Thus, although it is necessary to retain some gas-fired capacity while low-carbon dispatchable technology (such as long-duration storage) reaches maturity, investing in fossil-fuel-fired generation capacity to enhance energy security could result in stranded assets, lock-in of emissions and exposure to natural gas price volatility.

Indeed, low-marginal-cost VRE generation and storage displace a significant amount of gas-fired generation during 2035. The overall capacity factor of unabated gas-fired plants falls to around 10% despite demand increases, compared to around 46% in 2023, as gas generation still provides reserves and system services in 2035. Although technologies such as batteries contribute to reserves today, significant hurdles must be overcome to realise the Climate Action Plan 2023's ambition of 100% reserves from low-carbon sources.

While grid-forming inverters and batteries can provide essential system services, their deployment at scale remains limited. This challenge extends beyond the services themselves, as control systems must also be adapted to ensure reliable and effective delivery. Today's power systems still rely heavily on synchronous machines – not only for physical inertia but for other critical services such as system restoration capability, system synchronisation signals, voltage control and overall stability. Chapter 4 discusses these aspects – particularly stability and voltage control – in more detail.

Under Adapted Transition Pathway assumptions, one further round of low-carbon inertia procurement delivers a total of 20 gigawatt-seconds (GWs) in 2035, below the minimum inertia level of 23 GWs. Detailed technical evaluation and real-world trials are required to verify that low-carbon sources alone can satisfy all requirements, with no guarantee that assets would be sited to provide the necessary locational balance of reactive power. Given these uncertainties and the security focus of this report, thermal generation still plays a minor role in reserve and system services in 2035.

Hourly generation during the week of median residual load in Ireland in the IEA Adapted Transition Pathway, 2035



Notes: DSM = demand-side management. Residual load is the total load minus solar and wind generation. Median is the middle value (not the mean) of all hourly residual load values in the year. Indigenous load is the load in Ireland, excluding exports to other jurisdictions.

In 2030, unabated gas generation clearly helps meet evening peak load together with imports as solar generation ramps down and demand increases. Nevertheless, extensive progress can still be made in reducing both emissions and imported fossil fuel use while some conventional gas capacity is retained to complement VRE generation.

While natural gas can remain in Ireland's generation mix to assure energy security, using less gas for power generation would improve the country's broader energy security by reducing its imports. In the Adapted Transition Pathway, total gas use for power generation decreases from 27 TWh_{th} in 2023 to 24 TWh_{th} in 2030 and 21 TWh_{th} in 2035, effectively reducing reliance on fossil fuel imports. Although gas consumption for power generation reduces as capacity factors decrease, higher total gas capacity and less-efficient peaking plants have a stronger effect towards 2035, dampening the reduction in fuel consumption despite the overall decline.

Maintaining capacity adequacy involves trade-offs across security, affordability and decarbonisation

Renewables, imports and storage suffice to meet Ireland's energy needs for most of the year in 2035 in the Adapted Transition Pathway. However, different conditions affect the system during periods of high system stress, such as at peak residual load. Annual peak residual load is projected to increase from 4.7 GW in 2023 to 6.3 GW in 2030 and 10.2 GW in 2035 in the Adapted Transition Pathway results, raising the question of how best to meet this growing demand.

Along with 6.9 GW of dispatchable generation in 2035, the Adapted Transition Pathway model meets demand in periods of system stress using available imports, storage and flexibility, with storage capacity growing significantly from around 1 GW today to 6 GW in 2035. While the system is able to meet demand reliably in the model, Ireland's strategy must consider a more detailed analysis to formulate an acceptable combination of thermal generation, storage, interconnectors and demand-side flexibility under an ambitious decarbonisation pathway, as each resource has its own distinct delivery, availability and operational risks.

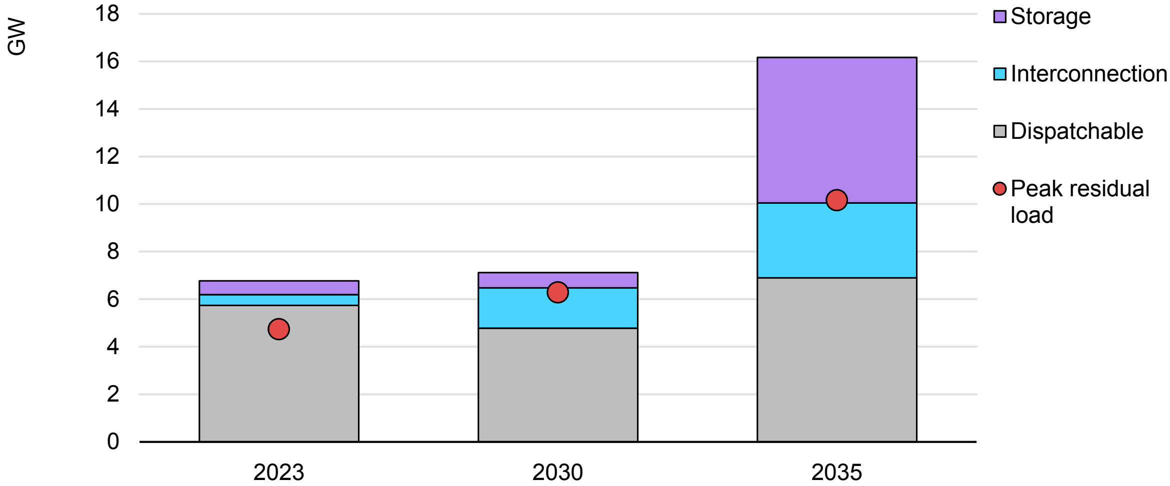
Expanding interconnector and storage capacity can improve Ireland's security position by diversifying its sources of supply beyond thermal generation. However, the contribution of interconnectors depends on timely construction as well as both physical asset and energy availability in the interconnected countries (France and Great Britain), which have different correlations with Ireland of demand and generation availability.

Meanwhile, achieving significant storage capacity growth depends on expanding market and dispatch arrangements (e.g. negative Physical Notifications to accurately report charging behaviour) to exploit its full potential. Unlocking the full value of storage to the system is essential to shore up the business case for the additional 5 GW of capacity assumed in the Adapted Transition Pathway by 2035, while the higher risk profile of long-duration storage may necessitate targeted support, as discussed in a later section.

Likewise, thermal capacity is not without delivery risks, as supply chain conditions for components such as gas turbines are tightening. Furthermore, increasing the prominence of gas in the capacity mix yields a less diverse supply mix and greater reliance on fossil fuel imports.

Firm capacity procured through Ireland's Capacity Remuneration Mechanism can eliminate the need for urgent short-term measures such as temporary emergency generation. However, procuring close to the expected peak residual load in thermal capacity – particularly in gas-fired generation – is likely to come at high cost if subsidies must cover most of the cost of the additional capacity, given that gas plants demonstrated low capacity factors in the 2030 and 2035 model results.

Installed generation capacity by category and peak residual load in Ireland, 2023 (historical), 2030 and 2035 (IEA Adapted Transition Pathway)



Notes: Peak residual load is the highest hourly value of total load minus wind and solar generation. Values for 2030 and 2035 are based on the Adapted Transition Pathway.

Such an approach risks delivering immediate electricity supply security by reinforcing imported gas dependence and locking in long-term costs, effectively replacing capacity adequacy concerns with gas supply, volatility and affordability concerns. Locking gas into a greater role in the power system would also increase the risk of payments for non-compliance with Ireland's emission commitments, neglecting end-consumer affordability concerns. Clearly, balancing the trade-offs involved in achieving energy security, affordability and decarbonisation while respecting Ireland's risk appetite is a key political challenge.

The power sector struggles to meet the 2030 emission target despite the emission intensity of generation falling considerably

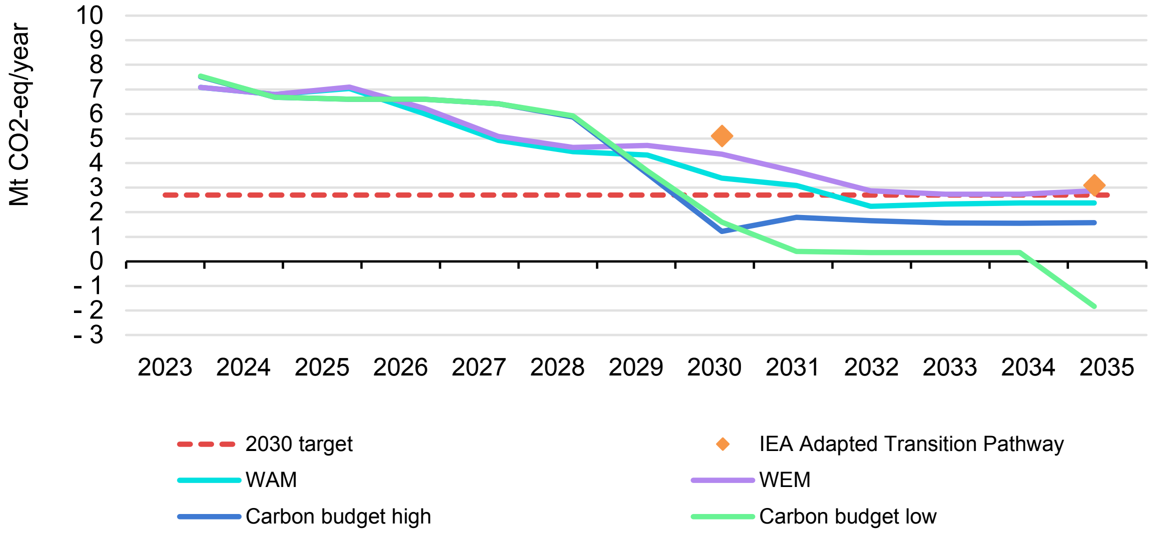
In the Adapted Transition Pathway results, Ireland's electricity sector emissions of 5.1 Mt in 2030 exceed its average 2026-2030 sectoral emission ceiling of 4 Mt per year[15] (a ~75% reduction from 2018). The model enforces operational constraints such as minimum inertia to provide results closer to operational reality, which may yield higher emissions than other models not imposing these constraints.

However, emissions drop to 3.1 Mt in 2035, less than one-third the 2018 level. By 2035, unabated gas withdraws to a backup role without being displaced entirely,

[15] The total sectoral emission ceiling for power in 2026-2030 is 20 Mt, i.e. 4 Mt per year. As 2026 emissions are likely to be higher, 2030 emissions would likely need to be below the average to meet the overall budget. In 2022, the government was aiming for 2030 electricity sector emissions of 3 Mt.

as low-carbon fuels such as hydrogen and technology types such as CCS are not expected to reach cost parity with unabated gas by 2035.

Total annual power sector emissions in Ireland by scenario, 2023-2035



Notes: WAM = With Added Measures (from SEAI National Energy Projections 2024 scenarios). WEM = With Existing Measures (from SEAI National Energy Projections 2024 scenarios). High-emissions and low-emissions scenarios are taken from the carbon budgets.

Sources: EPA (2025), Ireland's Greenhouse Gas Emissions Projections 2024-2055; MaREI-EPMG (2024), Carbon Budget Scenarios for the Climate Change Advisory Council Carbon Budget Working Group 2024.

Achieving this reduction in 2035 requires that Ireland meet its ambitious capacity deployment targets, which may require additional action. Renewable power capacity growth and the ability of the network to deliver VRE generation to consumers must outpace rapidly growing demand to keep the country on a downward emission trajectory in absolute terms.

The electricity sector's role in achieving Ireland's overall aims is multifaceted. Attaining electricity sector emission targets on time and in full would allow the country to transfer some emission reductions from electricity generation and other EU ETS sectors, to supplement its non-ETS reductions. Ireland currently plans to use the maximum non-ETS reduction transfer available under the EU Effort-Sharing Regulation. However, delaying electrification in other sectors such as transport and heat to achieve its 2030 power sector emission target prolongs fossil fuel use in those sectors, delaying Ireland's long-term national decarbonisation trajectory.

System and flexibility needs

Domestic and cross-border grid expansion are key to enable secure demand growth and VRE integration

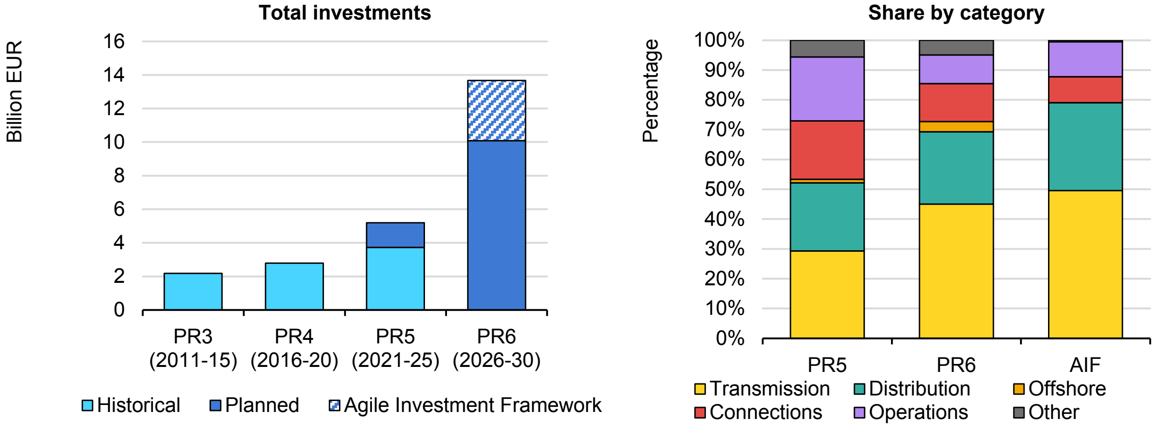
Expanding Ireland's transmission and distribution grids is critical to integrating new renewable electricity generation and meeting rising electricity demand. Transmission upgrades are needed to connect wind farms and new capacity to cities, industry and data centres, while distribution networks supply smaller industrial sites, smaller-scale renewable generation, businesses and households, and play a key role in electrifying heat and road transport. Across both networks, ageing infrastructure requires repair or replacement, and capacity can be enhanced through digitalisation and grid-enhancing technologies. These developments demand significant investments.

Responding to this growing need, ESBN and EirGrid have ambitious investment plans in place. In the Price Review Three regulatory framework covering 2011-2015, ESBN invested EUR 2.2 billion, and in the forthcoming Price Review Six (PR6) for 2026-2030, grid operators are collectively investing at least EUR 10 billion – an almost a fivefold increase. Further, PR6 contains an Agile Investment Framework (AIF), a flexible funding mechanism that allows for additional investment as system needs evolve. This means investments could rise to almost EUR 14 billion, with around 50% of AIF funding allocated to transmission infrastructure.

This approach aligns with the ESBN Build Once for 2040 strategy, which aims to reduce inefficiencies by anticipating long-term grid needs (it should be noted, however, that PR6 is still under consultation and the exact figures could change as the CRU finalises it). In addition to grid operator investments, private sector investment in grid infrastructure would be allowed under certain conditions if the government's Private Wires policy proposal is implemented.

EirGrid, designated as transmission asset owner for offshore infrastructure in 2021, is set to play a growing role in grid development. It is currently working on the Powering Up Offshore South Coast project to build infrastructure to connect 900 MW of offshore wind, and it aims to invest around EUR 350 million during PR6. It is also poised to take over the assets built under phase 1 of Ireland's offshore programme, which required grid infrastructure to be built by developers themselves. Depending on how many transfers take place, capital expenditures could range from EUR 335 million to EUR 3.8 billion under PR6, subject to regulatory approval. Additionally, EirGrid has committed over EUR 1 billion to operations and maintenance facilities for offshore renewables and grid infrastructure.

Grid infrastructure investments by ESB Networks and EirGrid, 2011-2030



Notes: PR = Price Review. AIF = Agile Investment Framework. Values include all capital expenditures by ESBN and EirGrid but exclude asset transfers of offshore infrastructure. The AIF column in the right-side chart corresponds to only amounts under the AIF (Agile Investment Framework) in PR6. "Connections" includes both customer and generation connections. "Other" covers IT infrastructure, the vehicle fleet and real estate.

Sources: IEA analysis based on S&P Global Market Intelligence; CRU (2025), Price Review Six Summary Paper; ESB Networks (2024), Price Review 6 Business Plan.

Because Ireland's distribution grid is relatively old (built between 1950 and 1980), many assets need to be reinforced and modernised. In 2024, 32% of its high-voltage distribution stations were already more than 60 years old, and 57% are expected to be this age by 2040. Overhead lines, transformers and underground cables are of a similar age, and they all typically have a lifespan of 30-60 years. Upgrading and expanding the distribution grid is thus essential to enable secure demand growth.

ESBN is also planning to undertake several operational measures. In its business plan for PR6, it allocated over EUR 1 billion to enhance distribution markets and system operation; improve grid monitoring and control systems; and develop flexibility markets. Additional investments support large-scale digitalisation, cybersecurity and telecom infrastructure upgrades, ensuring the grid is fit for a more dynamic and decentralised energy future.

In addition to expanding and modernising its grid, Ireland is deploying grid-enhancing technologies such as dynamic line rating (DLR), power flow controllers and topology optimisation to boost efficiency and defer costly upgrades. A 2022 DLR installation on the Lisheen-Thurles line enabled a new wind farm to connect without uprating the line. Building on this success, ESBN and EirGrid are developing a DLR policy document to further expand rollout.

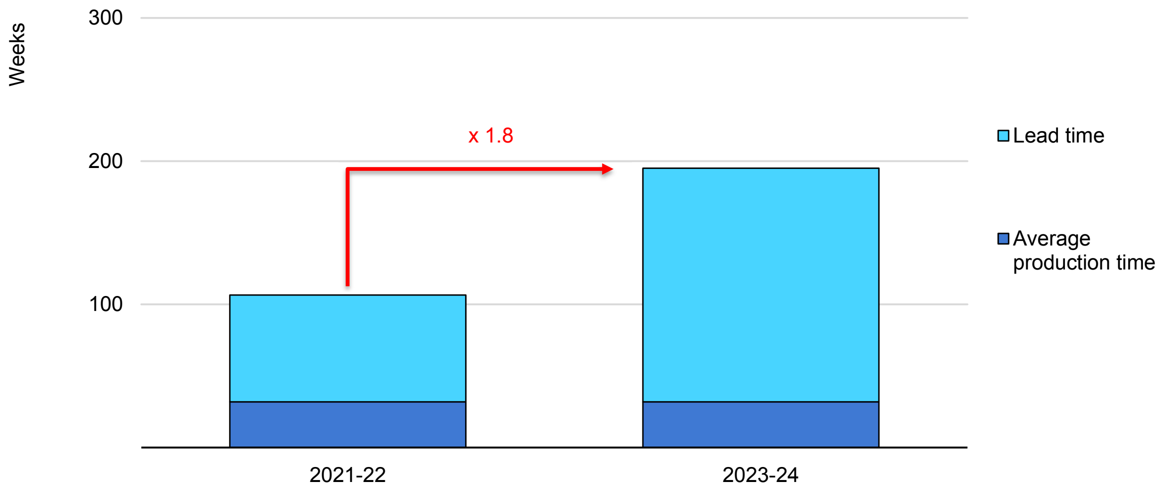
Supply chain risks can threaten the timely delivery of critical power system infrastructure

Delivering grid and generation infrastructure on time is critical to enable secure generation and demand growth. Global supply chain constraints can hinder the connection of new demand and renewable energy projects, and they can threaten system reliability if essential grid upgrades or generation and storage projects are delayed. These risks are compounded by high geographical supply chain concentration for key technologies and ongoing geopolitical tensions.

The global push for grid expansion, modernisation and renovation is putting considerable strain on the supply chains for essential network components such as transformers, switchgear and high-voltage cables. This could create risks for Ireland if it needs additional components beyond those already procured. As a result of higher demand, limited manufacturing capacity and shortages of critical materials such as electrical steel and copper, lead times for transformers have tripled since 2021 and now exceed three years in some cases. Consequently, the price of transformers has risen 75% since 2019 while cable prices have doubled.

Similarly, longer lead times and supply chain constraints are affecting the timely deployment of generation infrastructure. Deliveries of gas turbines for new gas-fired power plants are now subject to lead times of several years, potentially delaying commissioning to beyond 2029 or 2030. The rollout of battery, wind and solar technologies is increasingly at risk due to tightening critical mineral supply chains, especially for copper and lithium.[16] Rising export restrictions and supply concentration intensify these pressures, while offshore wind projects also face delays due to high demand for installation vessels and the need to upgrade port infrastructure to install offshore wind turbines.

Average lead time for large power transformers, 2021-2024



Source: IEA (2025), Building the Future Transmission Grid.

[16] Copper shortfalls could reach 30% by 2035, while a lithium deficit is expected in the 2030s amid surging demand.

Supply chain tightening might also affect Ireland's grid-buildout plans. For ESBN's PR6 portion, the delivery of over 500 capital resource projects is required, including more than 3 GW of new transformer capacity across various voltage levels; major upgrades to over 30 substations; and the replacement or conversion of tens of thousands of poles and kilometres of conductor lines. Many of the supply chains for these components are already constrained, and delayed component delivery could prevent key grid infrastructure from coming into operation on time.

However, to ease potential supply chain restrictions for grid expansion, ESBN has already undertaken a range of actions. In 2023, it set up a Transmission 2030 team to develop transmission-capital projects and manage supply chain risks, working closely with suppliers to ensure production aligns with needs. It has established frameworks for advance orders, including production slots for 25 high-voltage transformers and EUR 200 million of SF6 switchgear. Additionally, ESBN is standardising its equipment and optimising stock levels and lifecycles to streamline procurement and facilitate replacement and maintenance.

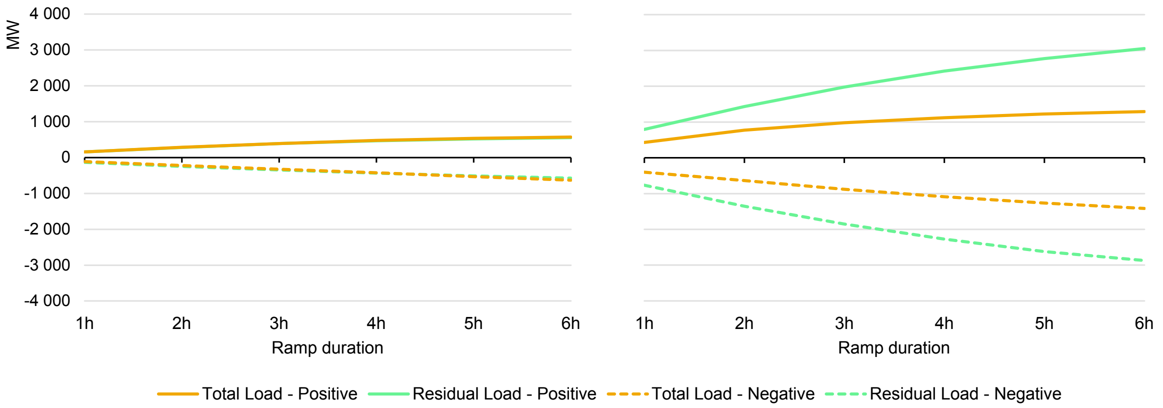
Flexibility needs increase substantially as variable energy sources play a greater role

VRE capacity expansion requires Ireland's power system to become more flexible. Although electrifying sectors such as heat and transport enlarges the pool of flexible resources, new power demand must be integrated in a system-friendly way. While larger commercial consumers respond to price signals more rationally, the effective participation of smaller consumers depends on an appropriate amount of consumer choice. The National Energy Demand Strategy therefore seeks to facilitate demand-side flexibility, including through new types of licences for aggregation and demand response providers to maximise the available capacity of flexible assets. Irish stakeholders can examine flexibility needs in further detail in the upcoming Flexibility Needs Assessment.

As well as helping the system manage periods of high demand, flexibility supports the investment case for VRE by providing renewable energy with a route to market in times of excess generation and network constraints. Batteries are technically well suited to balancing supply surpluses and deficits, but Ireland's market arrangements for battery storage (e.g. network charges) must be further developed to leverage the full value of storage to the system.

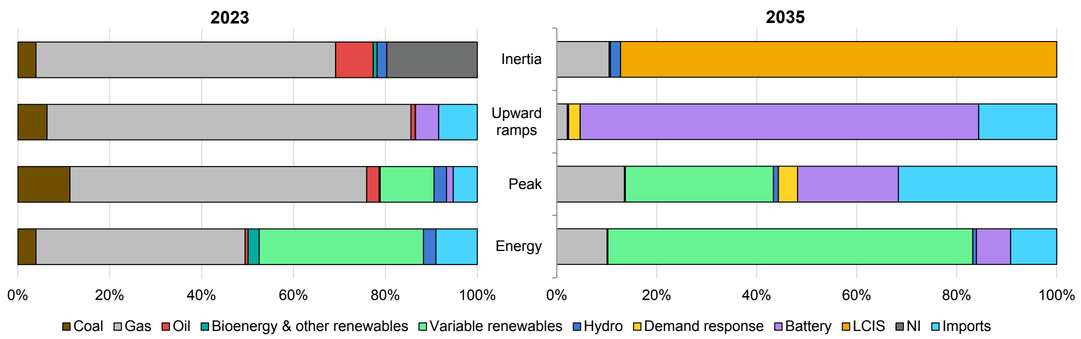
Solar and wind generation variations affect ramping requirements the most in 2035, whereas changes in underlying demand had the greatest effect in 2023. Ramping requirements triggered by underlying demand changes alone increase more than demand growth in the Adapted Transition Pathway (demand doubles while demand ramping requirements increase by a factor of 2.6). Solar and wind ramping requirements across durations increase by an average factor of five between 2023 and 2035, illustrating the need for flexibility to integrate these sources into the grid. Solar generation profiles require flexibility within each day, well suited to short-term assets, while wind generation profiles are flatter and better match seasonal demand in Ireland, generating more energy in winter than summer.

Mean positive and negative ramps by duration in Ireland in the IEA Adapted Transition Pathway, 2023 (left) and 2035 (right)



Notes: Ramps are calculated as the mean of the sum of changes. Values for 2035 are based on the Adapted Transition Pathway.

Contribution to energy, flexibility and adequacy services by technology in Ireland in the IEA Adapted Transition Pathway, 2023 (left) and 2035 (right)



Notes: LCIS = low-carbon inertia services (inertia provided by non-energy units procured through the Low Carbon Inertia Services programme). NI = Northern Ireland (inertia provided by plants in Northern Ireland in 2023 to meet the All-Island inertia floor). "Inertia" includes both Ireland and Northern Ireland, while other categories cover Ireland alone. Inertia is calculated as the requirement to meet the 23-gigawatt-secod (GWs) inertia floor, i.e. the first 23 GWs in merit order in each hour of the year. The "upward ramps" category is calculated as ramping energy provided during the year's 100 largest upward residual load ramps. "Peak" is energy provided during the year's 100 highest peaks. "Energy" is the total energy provided over the year. Values for 2035 are based on the Adapted Transition Pathway.

Key electricity security challenges in 2030

As demand projections are more certain for 2030 than for 2035, supply risks are a dominant aspect of security challenges in 2030. These supply risks affect both the provision of capacity to meet demand and the country's ability to ensure sufficient flexibility and energy efficiency. As the brief period from now to 2030 leaves little time for course-correction, it is not feasible to deploy additional high-voltage networks beyond those already committed or to make large increases in offshore wind capacity, which limits their influence in mitigating potential energy security risks.

Capacity procurement and delivery timelines are likewise tight to 2030. Two auctions remain to procure additional conventional capacity for 2030 through the Capacity Remuneration Mechanism. The first, scheduled for early 2026, is the only auction left for delivery before 2030, while the subsequent auction would procure further capacity in time for winter 2030/31.

Renewable power capacity procured in the remaining five years to 2030 may also struggle to come online by that year – particularly larger projects and offshore wind installations subject to more complex planning, permitting and capital intensity requirements. Delivery by 2035 remains within reach but concerted action is needed to align capacity delivery with the 2035 target pathway.

Ireland risks missing its 80% renewable electricity target in 2030, reaching 67% in the Adapted Transition Pathway

The Adapted Transition Pathway results show that the country may not meet its target of 80% renewable electricity[17] in 2030. Instead, sustained momentum in onshore wind and solar deployment combines with increased imports from interconnection to increase Ireland's share of renewable electricity to 67% in 2030. Onshore wind generates the majority of this, with offshore wind contributing 6%. Minimising curtailment due to network constraints and lack of flexibility in times of surplus will be decisive in reaching this target.

If Ireland does not meet its renewable capacity deployment targets, it risks missing its overall renewable electricity and decarbonisation targets. Lower offshore wind generation would leave the country with less diversified supply sources and more exposure to supply security vulnerabilities. Meanwhile, solar PV has shorter lead times than wind, requires fewer parts and has simpler installation and lower upfront capital costs, reducing cost-of-capital risks. Deploying additional solar

[17] For the purposes of Ireland's 80% by 2030 target, "renewable electricity" is as defined in the EU Renewable Energy Directive 2018/2001, as well as imports.

capacity by 2030 is therefore realistic and a dual wind-solar focus could improve Ireland's position in relation to its targets.

Below-target offshore wind capacity increases Ireland's reliance on electricity imports to meet peaks in 2030

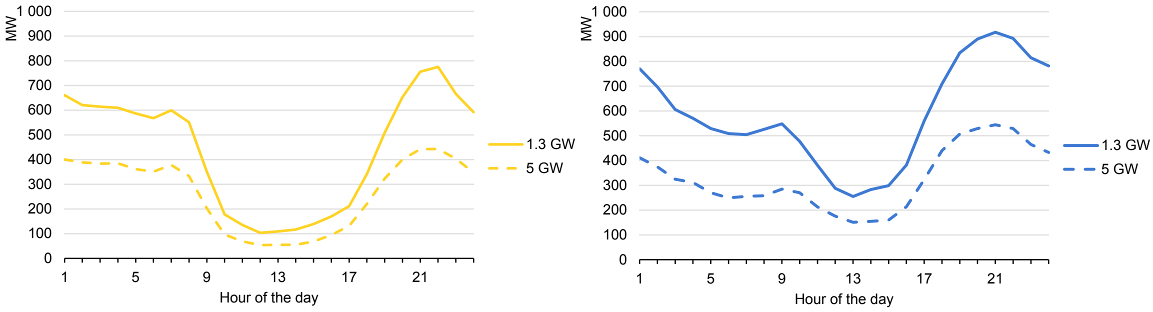
In the Adapted Transition Pathway, Ireland imports more electricity in 2030 to make up for the shortfall in targeted offshore wind capacity, notably towards the end of the day during the typical winter evening peak. Although increased demand flexibility is expected to smooth the demand curve slightly in the 2030s, supplying enough power for early-evening consumption is likely to remain a key operational challenge as residual load ramps up while demand rises and solar production ramps down.

While regularly serving baseload or ramping power requirements with interconnector imports is not necessarily undesirable, structural reliance on interconnectors to meet daily capacity needs introduces system operation risks and depends on Ireland's strategic prioritisation of different risks. Interconnector flows are less predictable than dispatchable generator availability because they broadly follow interconnected countries' price spreads, which can swing up to the day of delivery.

Ireland benefits from implicit interconnector coupling with Great Britain and will recouple with continental Europe once the Celtic Interconnector is operational. Since the withdrawal of the United Kingdom from the European Union, there has been no day-ahead trading over the existing interconnectors between Ireland's SEM and Great Britain, with their positions determined in two coupled intraday auctions. This intraday coupling reduces the complexity of managing interconnector flows for the system operators and is more efficient than the explicit coupling between Great Britain and other EU countries, under which transfer capacity and energy are traded in separate auctions.

Without day-ahead price signals, interconnector positions are not known to system operators until the morning of each day, leaving them less opportunity to prepare units with long start times if a shortfall is expected during the evening peak. Limiting the permissible ramp rate of interconnectors to 5 MW per minute per interconnector is one way system operators in the SEM manage interconnectors effectively.

Mean gross hourly electricity imports by installed offshore wind capacity in Ireland in the IEA Adapted Transition Pathway, summer (left) and winter (right), 2030



Note: GW capacity in the legend indicates installed offshore wind capacity for each sensitivity analysis. Ireland has 2.9 GW total import capacity in 2030 in the Adapted Transition Pathway.

Higher electricity demand from housing further increases import reliance in 2030

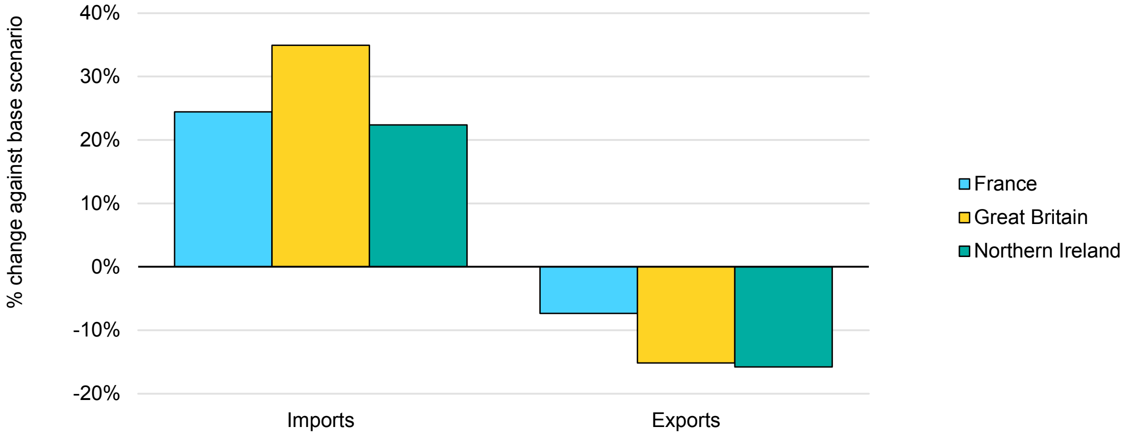
Along with the electrification of existing fuel demand, the construction rate of new buildings will influence power demand growth. Following a population increase of 8% between 2016 and 2022, the Housing Commission identified a deficit of over 200 000 homes in 2022. Consensus exists around the need for new housing in Ireland but forecasts range from 35 000 to 53 000 new homes per annum, with recent forecasts tending high. The government target of 300 000 new homes by 2030 is a strong signal but the electricity system is sensitive to the timing, number and location of new buildings.

The recent increase in forecasts of new housing needs raises the risk that electricity system planning underestimates demand growth from this sector. To test this risk, Adapted Transition Pathway modelling used recent ESBN data to evaluate the effects of higher-than-forecast electricity demand, should Ireland succeed in building over 50 000 houses per year to 2030. Meeting this target raised peak residual load from 6.9 GW to 7.2 GW in the model results, placing an additional burden on both generators and the network.

In the sensitivity exercise, the electricity system responded to higher residential demand by relying on increased imports to support domestic generation. Power demand from residential heat reached 5 TWh by 2030 – 87% higher than in the baseline scenario for that subsector. The import-export balance of the system shifted to serve this additional demand, increasing exposure to interconnector availability risks.

As noted in Chapter 2, managing additional residential connections requires supply-side action and co-ordination across the supply domain, from generation to low-voltage distribution circuits. Synchronised planning of network capacity and deployment is required for the additional substations that are planned for the interface of transmission and distribution grids, an instructive example of how different policy objectives must be considered in energy system planning. Measures to improve the energy efficiency of existing and new housing stock have the dual benefits of reducing energy costs for consumers and smoothing residential demand profiles.

Changes in gross electricity transfer to and from Ireland under higher residential and commercial demand by interconnected jurisdiction in the IEA Adapted Transition Pathway, 2030



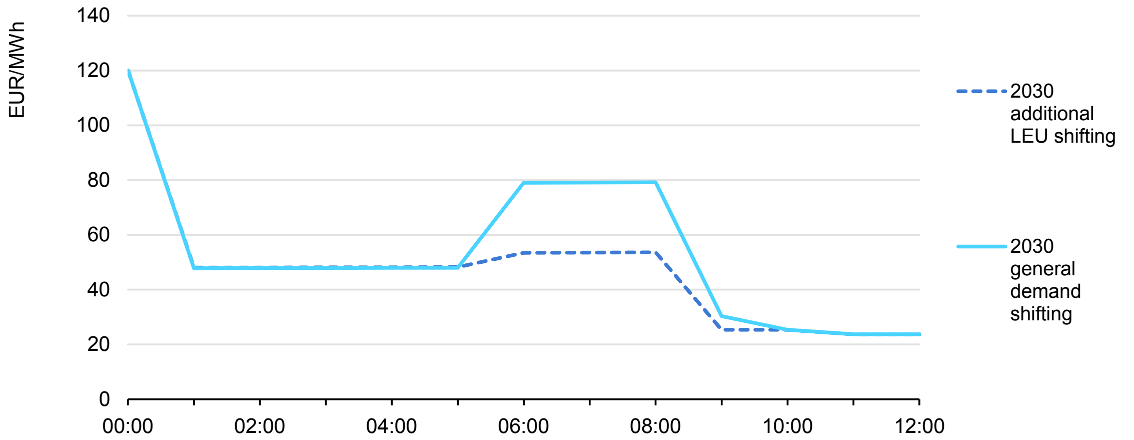
Note: Ireland and Northern Ireland form a single bidding zone (the Single Electricity Market).

Higher data centre demand flexibility can reduce system stress

In the Adapted Transition Pathway, data centres are the most important driver of electricity demand growth in Ireland to 2030. How flexibly this additional demand operates is an important component of unlocking demand flexibility equivalent to 20-30% of peak demand in 2030. Currently, data centres show less responsiveness to wholesale price signals than other large energy users, having a more uniform hourly demand profile across the day. Wholesale market price signals alone may not suffice to unlock the desired flexibility from data centre demand, particularly as a flat demand profile lends itself to rigid baseload power purchase agreements.

In Ireland, large energy users can register as Demand-Side Units to earn revenue by reducing their consumption when instructed to by the system operator. Similarly, by introducing a new balancing-unit class (Dispatchable Consumption Units), the system operator hopes to encourage large energy users to increase their demand in times of renewable electricity surplus. However, it is uncertain whether data centres are technically able and economically willing to shift certain operations away from high-demand periods and/or towards supply peaks. Given their historical price elasticity of demand, they may not be well suited to providing regular "dispatch-down" services, instead acting as peak-shaving capacity for a smaller number of hours each year.

Hourly wholesale prices during large energy user demand-response activation in Ireland in the IEA Adapted Transition Pathway, 2030



Note: LEU = large energy user.

Additionally, the CRU draft decision on large energy users would require data centres to build their own generation capacity and make it available to the wholesale market, limiting opportunities for them to reduce grid demand by ramping up onsite generation instead. Initial investigations into shifting the time and location of data centre operations remain in early stages, with the technical and economic viability of widespread shifting as yet unknown.

During low-VRE periods in 2030, interconnectors and gas dominate while batteries and demand response cover peaks

Systems with higher shares of weather-dependent VRE capacity must be able to operate securely in periods of low VRE availability. As VRE covers 62% of generation in the Adapted Transition Pathway in 2030, a sensitivity study investigated how the power system might meet demand during the two-week weather period with lowest VRE availability in the last 20 years.[18]

In the scenario results, electricity imported via interconnectors makes a sustained contribution to meeting baseload demand over the low-VRE period in 2030, with the Celtic Interconnector connection with France adding another dimension to Ireland's electricity supply security. Despite periodic unplanned outages of its large nuclear fleet, the French market's lower exposure to gas price volatility and weather-dependent generation shields it from some of the most significant risks facing the Irish electricity sector, making it a valuable complement to domestic generation. However, interconnectors can make operational planning more complex, as the scheduled day-ahead and real-time position and direction of each interconnector for a given delivery period can change significantly across the various auctions, particularly in times of market scarcity and high prices.

As interconnectors can also export excess VRE generation, demand from interconnected countries may compete with indigenous daily flexibility requirements (e.g. for demand shifting and short-duration storage) during periods of regionwide stress. As the system develops, regular reviews of operational tools and of agreements with interconnected countries' system operators (e.g. concerning Emergency Assistance and Emergency Instructions) will ensure transparent, co-operative and effective decision-making in times of scarcity.

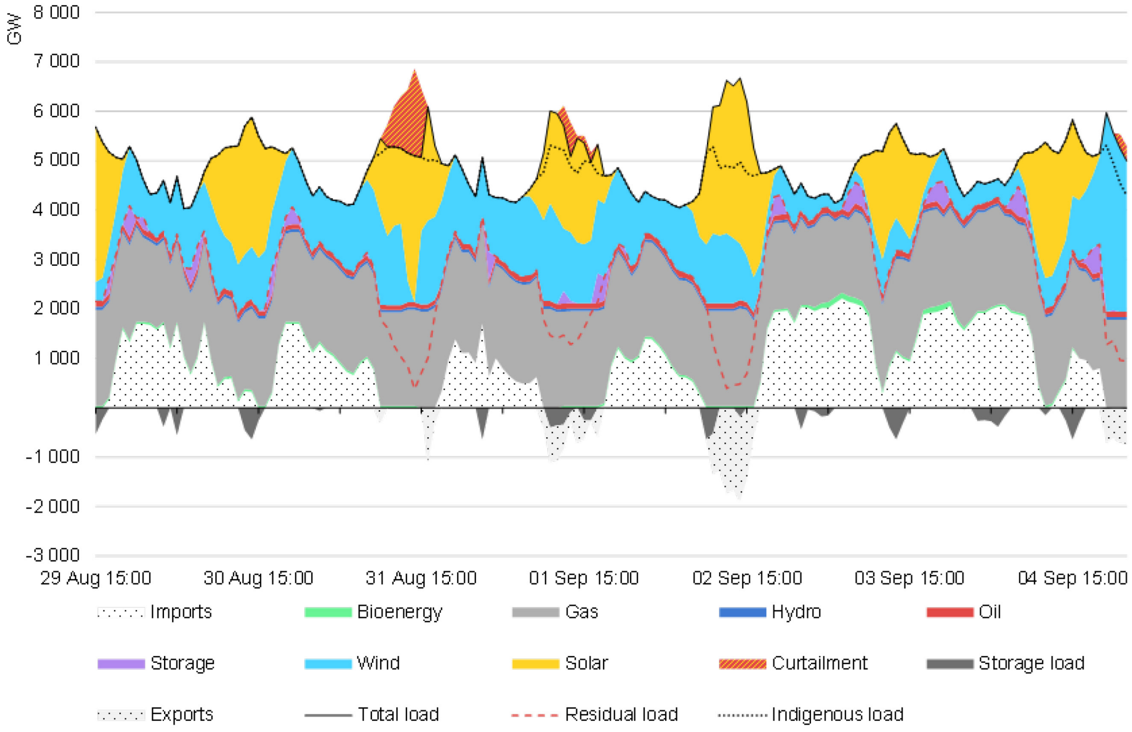
In contrast to their diminished use over the rest of the year, gas-fired units continue to be vital in low-VRE periods in 2030, generating substantial baseload power and flexibility to accommodate residual load ramps. While lower-marginal-cost VRE displaces fossil-based generation when available, by 2035 the role of gas during this two-week period must be fulfilled by technology types such as long-duration

[18] The modelling annex explains the methodology in more detail.

energy storage and responsibly sourced biomass. Hydro and biomass resources currently provide only limited low-carbon baseload electricity due to their limited capacity.

Battery storage also helps meet demand peaks in 2030 while providing valuable daily flexibility, shifting generation from periods of low to high residual load, discharging during morning and evening ramps, and contributing to system reserves.

Hourly electricity generation by source during a low-VRE period in Ireland in the IEA Adapted Transition Pathway, 2030



Note: Based on an August-September 2021 weather period that had the lowest two-week rolling average capacity factor for solar and wind generation potential of the previous 20 years. Indigenous load is the load in Ireland, excluding exports to other jurisdictions.

Source: IEA analysis based on European Centre for Medium-Range Weather Forecasts 2025 data; ECMWF (2025), Reanalysis v5.

Resolving the interdependent challenges in 2030 requires co-ordinated policy action. Deployment delays for capacity such as offshore wind and long-duration storage affect demand-side decisions and raise the need for other capacity. However, policy measures for large energy users can steer the integration of additional demand into the system, better preparing it for uncertainties and evolving risks in 2030. Many of the concerns present in 2030 persist to 2035, but greater exposure to risks such as weather-related hazards in a high-VRE system are also accompanied by more opportunities for mitigation with prompt and decisive policy choices.

Key electricity security challenges in 2035

In contrast to the 2030 horizon, the 10-year period to 2035 allows more time for policy action and plan implementation to affect outcomes and address generation capacity delivery. Although the extent of demand growth remains uncertain, policies can determine how new demand is integrated into the electricity system, establishing appropriate frameworks for energy efficiency, the flexible operation of new loads and grid reinforcement to meet additional needs.

If the country succeeds in meeting its VRE deployment targets, natural gas use in the electricity sector will be increasingly limited to providing system security, mitigating Ireland's current vulnerabilities stemming from reliance on gas-fired generation. To enable this change, both operational actions (to enable high VRE penetration) and market and regulatory measures (to allow gas-fired generators to remain in the market and be used when needed) are vital.

Compared to 2030, higher end-use electrification and VRE generation further increase the need for system flexibility across all time frames in 2035. Low-wind-resource events could exert greater strain on the grid than in 2030, making access to a diverse pool of resources even more essential.

This 10-year time frame also creates grid development opportunities for projects already in the pipeline. Interconnection is assumed to expand to 4.4 GW (including links with Northern Ireland) in the model – 1.5 GW more than by 2030 and nearly 3 GW above the 2023 level. Additionally, ESBN has laid out plans to develop the onshore grid infrastructure capacity required to accommodate Ireland's electrification ambitions.

This section assesses the electricity security implications of different demand pathways linked to various electrification outcomes and different flexibility needs stemming from higher weather-dependent supply and demand. While energy conservation efforts are also essential for energy security, determining their impacts requires further end-use-sector modelling, which is outside the scope of this report.

VRE can cover most energy needs in 2035 if capacity is built

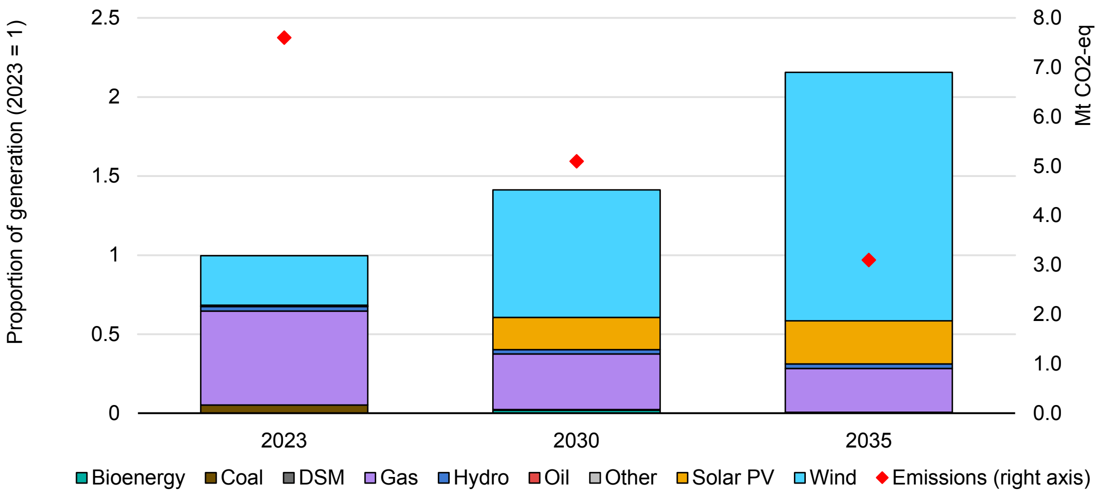
Sustained VRE capacity deployment in the 2030s enables renewable electricity to supply 88% of Ireland's electricity in the ambitious 2035 scenario results, demonstrating the significant role VRE can play in Ireland's generation mix. VRE generation growth outpaces demand growth in 2035, succeeding in both displacing thermal generation and serving new demand.

Achieving this trajectory would, however, require continuous capacity deployment to 2035, without which Ireland's dependence on gas generation and imported fossil fuels would be prolonged. Siting new power consumers close to VRE installations could further raise VRE capacity use by minimising network constraints and related curtailment.

With VRE generation growth outpacing demand increases, average power generation emission intensity falls along with total power sector emissions. As the average emission intensity of generation decreases while demand grows, this pathway is likely to still reduce economy-wide emissions thanks to wider electrification, even if total power sector emissions do not meet the targets.

However, Ireland still risks not realising its national and European commitments, in which case it may have to pay non-compliance penalties for missing climate and energy targets agreed upon with its EU partners. If the country is to reduce its absolute power sector emissions to zero by the end of the 2030s, it must respond to the dual challenge of meeting new demand with low-carbon electricity while decarbonising existing supply sources.

Annual generation by source as a proportion of total 2023 generation (left axis) and annual power sector emissions (right axis) in Ireland in the IEA Adapted Transition Pathway, 2023, 2030 and 2035



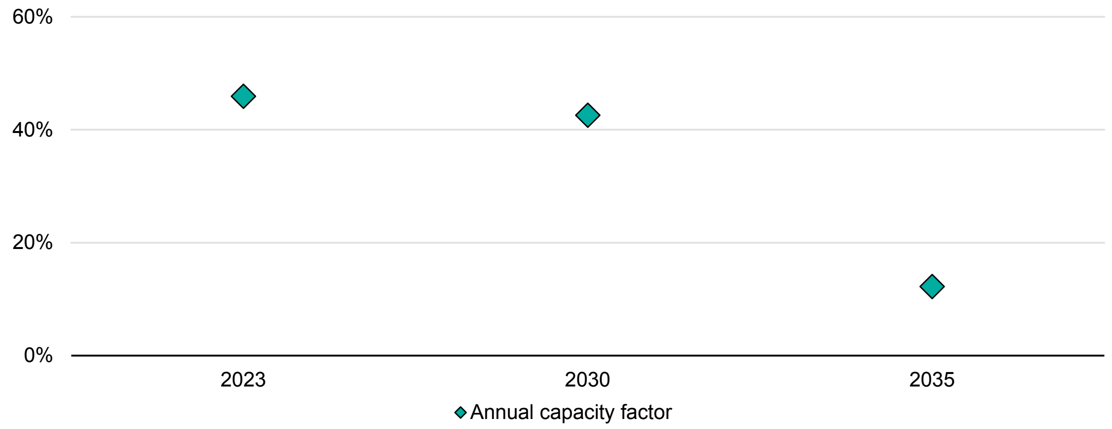
Notes: DSM = demand-side management. Values for 2030 and 2035 are from the Adapted Transition Pathway results.

Gas-fired plants operate close to minimum in 2035 as capacity factors decline, presenting economic and mechanical risks

Conventional generation continues to provide some system services and spinning reserve in the Adapted Transition Pathway results in 2035. As conventional plants provide constant inertia regardless of operating level when dispatched, running at minimum provides both a plant's full inertia potential and upward spinning reserve capability.

With renewable generation covering most electricity demand in 2035, large gas-fired plants generate at a capacity factor of around 12% in 2035, down from 46% in 2023. Operating at a lower capacity factor benefits Ireland's strategic position by reducing emissions and fossil fuel consumption but it introduces other concerns. For instance, running conventional plants close to their minimum stable levels increases mechanical wear, potentially necessitating more frequent planned maintenance and triggering plant trips.

Capacity factors of large gas-fired plants in Ireland in the IEA Adapted Transition Pathway, 2023, 2030 and 2035



Notes: Capacity factors are calculated using medium-size and large plants (>120 MW). Values for 2030 and 2035 are from the Adapted Transition Pathway results.

Similarly, investing in new conventional plants is considerably less attractive at low capacity factors. Capacity markets designed to provide partial revenue support on a per-capacity basis will not automatically account for the decreasing revenue outlook of lower capacity factors. Ireland's Capacity Remuneration Mechanism may therefore need to evolve to account for lower utilisation of conventional plants to ensure that they remain online for as long as needed.

In Great Britain, half of the capacity of a large combined-cycle gas project with a 15-year capacity market contract was recently cancelled, reflecting uncertainty over the long-term economics of gas generation in the region. Although some low-carbon fuels are included in the 2035 scenario, they are not expected to displace unabated gas in the market on a purely economic basis in 2035, even considering carbon costs. They are therefore dispatched as peaking capacity and as backup to unabated gas and will face similar challenges as conventional gas capacity.

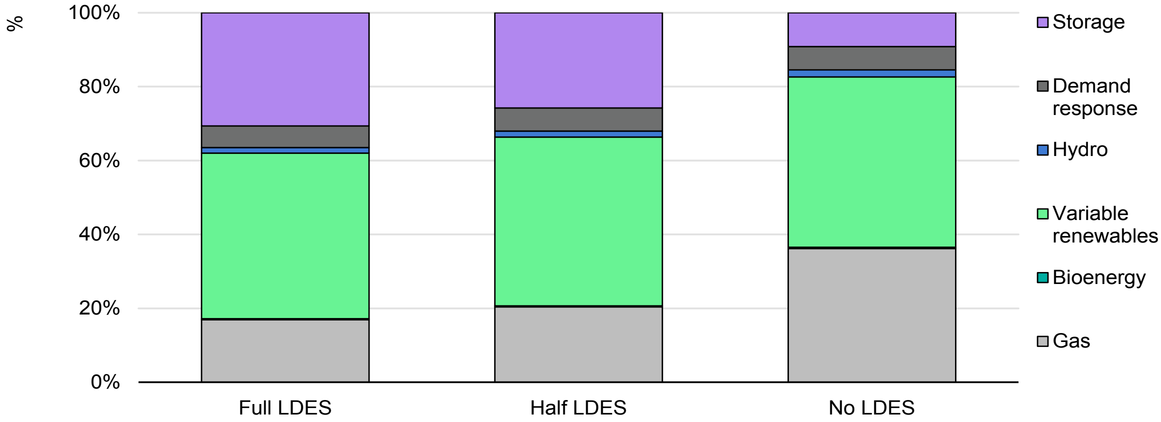
As declining gas use and consumers across the economy mean that network charges have to be borne by a smaller number of gas users, raising the cost, initiatives such as shorter depreciation periods and front-loaded asset value recovery are being investigated. Even if decommissioning sections of the network remains a distant prospect, discussions can begin now on appropriate mechanisms and thresholds to maintain gas supply effectively and fairly for a diminishing user base.

A lack of long-duration storage increases Ireland's emissions and exposure to gas-reliance risks in 2035

Long-duration electricity storage can reduce the need for dispatchable generation in a high-VRE system. Ireland's longest-duration operational storage is currently the Turlough Hill pumped-storage hydro plant, at around six hours. However, the ambitious scenario for 2035 defines long-duration electricity storage as more than 6 hours (beyond what is operational in Ireland today) and includes some 8- and 100-hour storage facilities, which would likely not be adopted without the incentives of a long-duration-storage policy.

In sensitivities in which longer-duration storage is only partially deployed or not built at all, shorter-duration storage is unable to compensate for the gap, and gas-fired generation increases. Higher gas-fired generation weakens Ireland's ability to meet its targets and exacerbates gas dependence – demonstrating the need for longer-duration storage in its future power system.

Proportion of generation during peak periods by source in Ireland in the IEA Adapted Transition Pathway, 2035



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Notes: LDES = long-duration energy storage, with 1.8 GW installed capacity in the base scenario. Peak periods include the 100 highest residual load periods.

Globally, commercially viable short-duration storage systems such as batteries have focused on the lowest-risk market segments, for instance intraday arbitrage and frequency response services. Capital expenditures for long-duration storage are higher than for short-duration and these costs are recovered from revenues earnt during scarcity periods, which are longer and more severe but less frequent.

Since relying on a small number of extreme periods to recover costs entails a higher investment risk than for short-duration storage, Ireland has formulated policy actions to establish a route to market for storage of four hours or longer. Nevertheless, more detailed implementation timelines for these actions would stimulate market confidence, especially as other jurisdictions are currently developing investment support mechanisms to incentivise long-duration storage projects (e.g. Great Britain's cap and floor scheme).

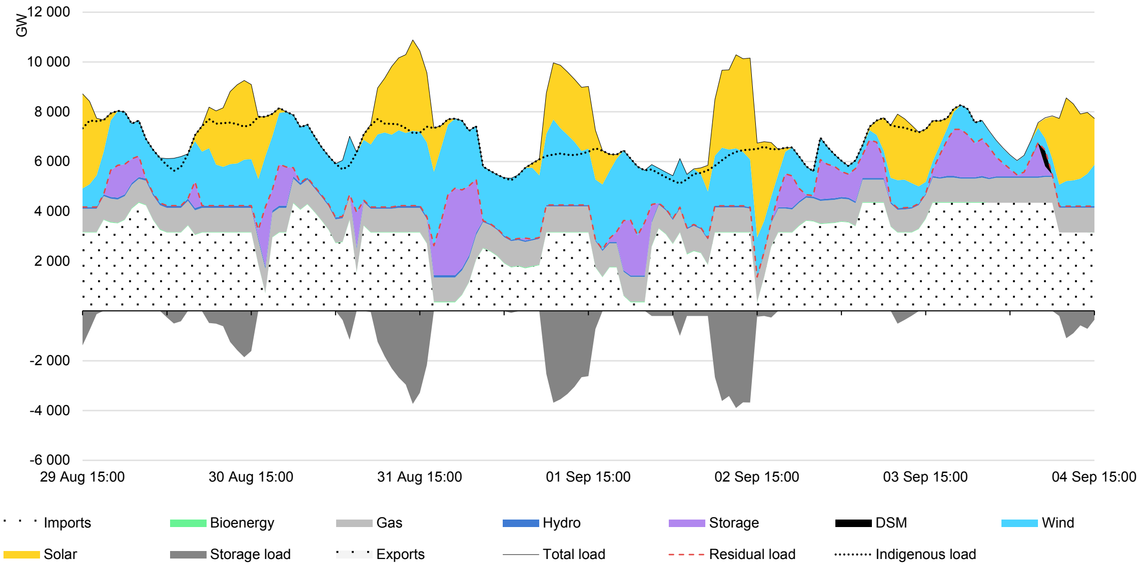
The regulator has more involvement in "cap and floor" instruments than other measures such as contracts for difference, allowing it to exercise greater oversight over costs before committing to the support. Similar instruments have also proven successful in delivering other capital-intensive infrastructure in Great Britain, such as new interconnectors.

Low-VRE periods in 2035 cause heavier reliance on imports and storage

As in 2030, Ireland's 2035 power system relies heavily on imports, storage and gas capacity to meet demand. Storage capacity provides a more significant contribution than in 2030, shifting larger amounts of energy from solar resources and imports from the middle of the day to the evening peak period. This makes the best use of available VRE generation, maximising system efficiency by preventing curtailment while stabilising generator revenues. Ireland does not export at all during this period as storage capacity is sufficient to absorb all excess VRE generation.

This operating pattern reduces system stress during evening demand peaks, when conventional plant and interconnector trips are most likely as units ramp up. It also reduces structural reliance on the availability of electricity over interconnectors at the time of day when electricity is scarcest, reducing exposure to import unavailability during periods of regionwide system stress. Overall, however, Ireland continues to rely heavily on imported electricity during low-VRE periods, despite the mitigating effects of storage resources.

Electricity generation during a low-VRE event in Ireland in the IEA Adapted Transition Pathway, 2035



Notes: "Gas" includes low-carbon fuels. "Indigenous load" is the load in Ireland, excluding exports to other jurisdictions.

Greater reliance on interconnection increases exposure to unplanned outages and multi-region extreme events

Expanding its interconnection capacity diversifies Ireland's supply portfolio, particularly as it establishes connections with multiple markets. Interconnectors smooth market extremes in isolated systems and can provide an export route for surplus renewable generation that would otherwise be curtailed.

As with all electrical assets, relying more strongly on interconnection brings risks as well as benefits. By smoothing market extremes, they also dampen price arbitrage signals for storage. Furthermore, accidental interference with subsea interconnectors from ships is a common occurrence, from small fishing vessels trawling nets to large tankers dragging anchor. Ireland's interconnectors with Great Britain cross the Irish Sea, a shipping lane between the islands of Ireland and Great Britain, while the Celtic Interconnector to France will cross busy shipping routes linking the Atlantic Ocean with North Sea and Baltic Sea ports. Intentional sabotage of subsea infrastructure is also becoming more common, though incidents remain rare overall, while interference with onshore infrastructure remains a concern.

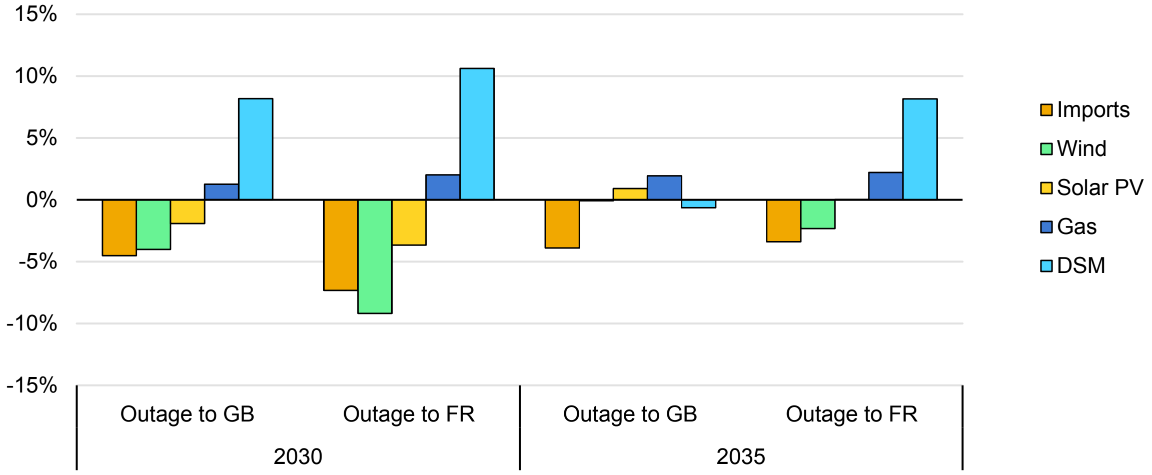
Similar to generators, interconnectors can suffer unplanned outages from a variety of causes (e.g. substation fires), presenting risks of both instantaneous large infeed loss and longer-term capacity unavailability. Recent events such as the simultaneous tripping of the Moyle and East-West interconnectors in May 2024 demonstrated the effects of interconnector trips on the Irish system.

Beyond physical hazards, greater reliance on interconnection introduces market risks. Concurrent market coupling with continental Europe and Great Britain may complicate generation and interconnection planning and management across various timescales. In times of regional system stress (e.g. winter 2022/23), high prices across northwestern Europe may cause extreme market outcomes and volatile interconnector flows.

Sensitivity studies explored the potential effects of interconnector capacity unavailability over the year in Ireland in 2030 and 2035. In most cases, demand response and gas-fired generation increase to cover the shortfall in imports. In 2030, wind-based generation also falls because the ability of interconnected markets to absorb surplus availability in Ireland is limited. This demonstrates how interconnections can serve as positive-balancing sources in Ireland's electricity system.

In 2035, the results for Great Britain and France diverge, as both Great Britain and Ireland have heavily wind-based systems, limiting the balancing effects of interconnections, while France retains its strong nuclear base. All interconnector sensitivities show that relying on increased gas generation and demand response to compensate for interconnector unavailability puts stress on the system.

Energy provision changes by technology under interconnector outage sensitivities against the baseline in Ireland in the IEA Adapted Transition Pathway, 2030 and 2035



Notes: GB = Great Britain. FR = France. DSM = demand-side management. "Outage to GB" is a reduction of 500 MW of interconnection capacity between Ireland and GB. "Outage to FR" is a reduction of 700 MW of interconnection capacity between Ireland and France, representative of the outage of a single interconnector for the whole year.

Chapter 4. Future challenges to operational security and resilience

Ireland's power system is undergoing profound transformation to meet ambitious decarbonisation targets – 80% renewable electricity supply by 2030 and an even greater portion by 2035. While the energy transition is a key driver of change, growing electrification across sectors and the emergence of new electricity demand sources, such as data centres, are also placing increasing strain on the system. These developments, alongside geopolitical pressures and extreme weather events, present unique challenges for maintaining power system reliability.

This chapter investigates these hurdles through the distinct yet interconnected concepts of operational security and resilience. The IEA defines operational security as an electricity system's ability to retain or quickly return to its normal state after any type of event. It reflects the system's stability, ability to respond to equipment failures and its capacity to maintain supply-demand balance.

Meanwhile, resilience refers to the ability of the system and its component parts to absorb, accommodate and recover from both short-term shocks and long-term changes that might not be covered in standard operational security assessments.

For example, when a large generator unexpectedly trips offline, operational security mechanisms deploy operating reserves to quickly restore the supply-demand balance and return the system to normal operating conditions – typically within seconds to a few minutes. However, when a major storm, flood or other event damages physical grid assets such as electricity poles, resilience capabilities determine the system's ability to absorb the initial impact, maintain critical services and undertake recovery efforts.

As Ireland works to achieve its 2035 energy goals, interconnected challenges will test its operational security and resilience. First, managing operational security will become increasingly complex as converter-connected renewable energy sources displace conventional generation, requiring new approaches to stability management, large-load integration and system service provision. Then, physical resilience trials will intensify as ageing infrastructure is subjected to extreme weather events. These challenges will merge as operational security measures are called upon to reinforce resilience, while resilience planning must take account of the operational realities of a high-renewables electricity mix.

Our analysis is based on the Chapter 3 reference scenario, the Adapted Transition Pathway, and examines how Ireland can navigate operational security and resilience challenges while maintaining its position as a global frontrunner in renewable energy integration. This chapter's insights inform our Chapter 5 policy recommendations.

Operational security: Managing stability risks

The All-Island power system of Ireland and Northern Ireland is small relative to the world's major power systems. Thus, as a small, island-based synchronous system, it faces greater challenges in managing stability – largely due to its size, lower system inertia, restricted interconnection capacity and limited benefits of scale when responding to disturbances. Larger and more meshed systems – such as those of central Europe and parts of North America – can often manage comparable disturbances more easily, as the effects can be distributed across a broader network. However, large systems are not immune to stability problems either, particularly when subjected to major, wide-ranging events.

Ireland's power system stability will be put to the test as conventional generators with inherent stabilising characteristics are replaced by converter-connected resources with different technical properties. Importantly, stability management extends beyond frequency control and inertia. As the power system evolves, the mechanisms that provide reactive power control, voltage regulation and other functions must also adapt to ensure secure operations.

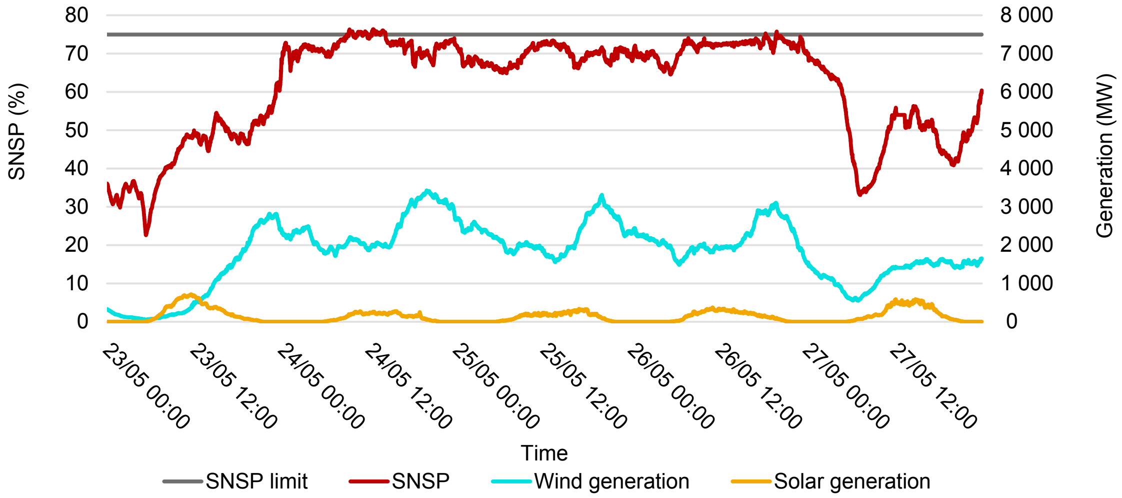
Meanwhile, operational security depends on a wide range of factors: power flow management; dispatch operations; and transmission limit settings. This section focuses specifically on stability-related risks in Ireland's evolving power system to 2035. It examines how high shares of converter-connected resources are changing the nature of stability challenges, then explores emerging risks from large, concentrated loads such as data centres. Finally, it discusses the need to define and adapt system services to effectively manage these risks.

Operational practices need to be proactively adapted to integrate considerable converter-connected resources while preserving system stability

Ireland has made remarkable progress in integrating renewable energy while maintaining system stability. It now regularly operates at system non-synchronous penetration (SNSP) levels approaching 75%, as demonstrated during the week of 23-27 May 2025 when wind and solar resources provided most of the electricity supply for extended periods.

This achievement is a global milestone, but it also highlights the fundamental challenge ahead: as converter-connected renewable power sources displace conventional synchronous generators, the power system will lose many of the inherent physical properties that have traditionally provided inertial response and helped maintain system stability. Maintaining secure system operations while transitioning to renewable energy will therefore require new approaches to system stability, innovative service procurement and adaptive operational practices. Management measures in three focus areas will be necessary to ensure system stability: inertia and frequency; voltage; and system oscillations.

Power system operations at high system non-synchronous penetration in Ireland, 23-27 May 2025



Note: SNSP = system non-synchronous penetration.
Source: EirGrid, as modified by the IEA.

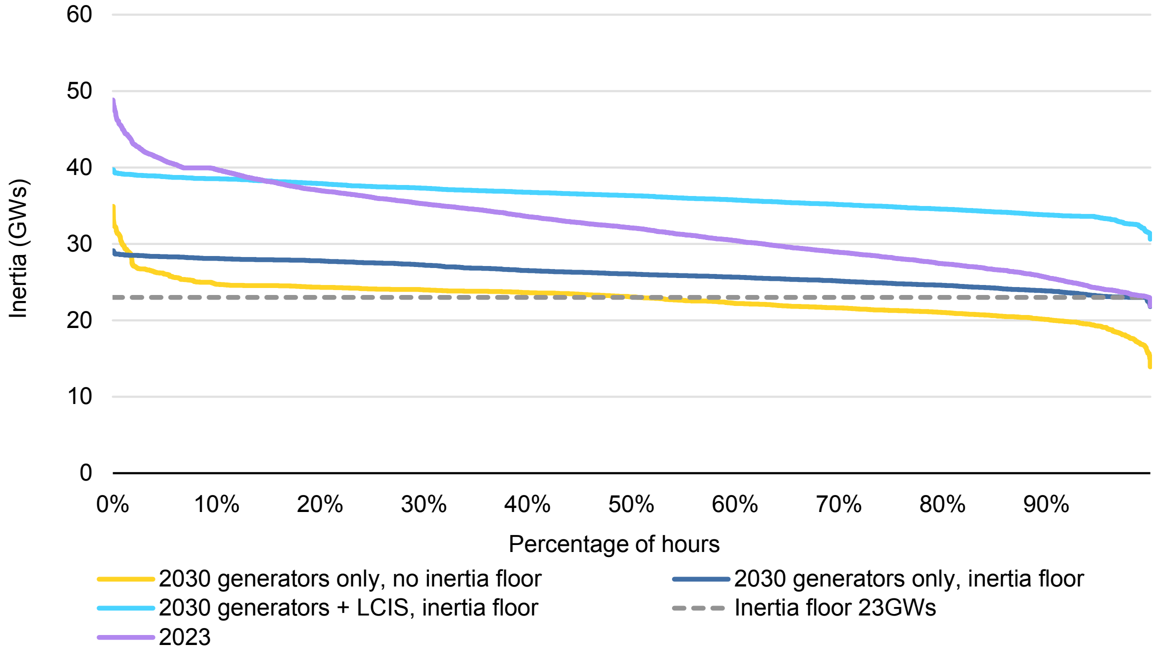
Inertia and frequency management

Traditional synchronous generators inherently possess inertia due to the kinetic energy stored in their spinning rotors, as well as in magnetic fields during the energy conversion process. This inertia enables them to naturally resist system frequency changes during supply-demand imbalances. However, as converter-connected variable renewable energy (VRE) sources displace synchronous machines, their inherent physical inertia is being lost to the system.

Unless new sources of inertia are introduced, the system's ability to resist rapid frequency changes diminishes. Lower inertia means that frequency will vary more rapidly and widely following disturbances such as the loss of a large generator, potentially leading to equipment damage and widespread outages if not properly managed.

In Ireland's synchronous area, this challenge can be particularly acute. Our analysis under the IEA Adapted Transition Pathway indicates that, if operating constraints are not enforced, the system would operate with inertia below the minimum requirement for roughly half of 2030. This demonstrates the need to carefully determine operating limits to avoid unacceptable frequency volatility.

Inertia duration curve with and without low-carbon inertia services in Ireland, and inertia floor, 2023 and 2030



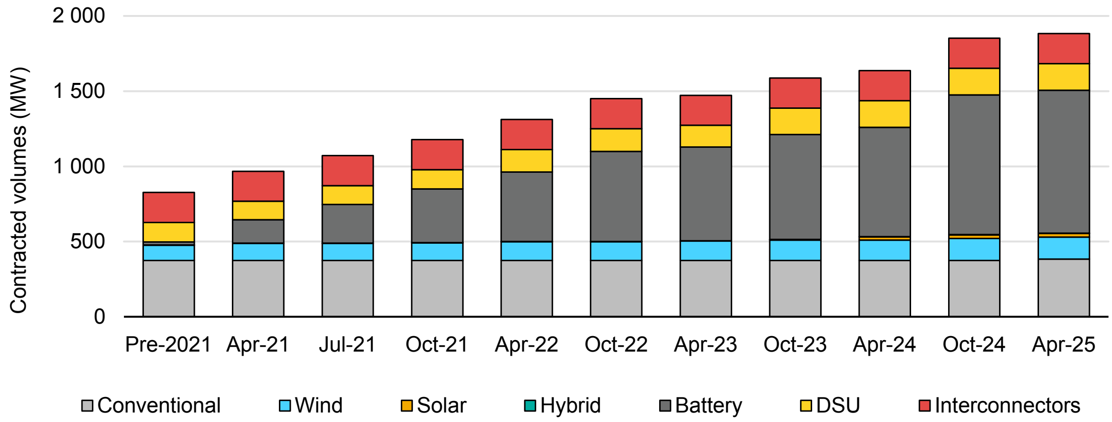
Notes: GWs = gigawatt-seconds. LCIS = low-carbon inertia services. The inertia shown is rotating inertia from synchronous machines, generators and contracted low-carbon inertia services (primarily synchronous condensers). The current All-Island minimum inertia requirement is 23 gigawatt-seconds. Values for 2030 are based on the IEA Adapted Transition Pathway scenario.

Ireland has implemented several strategies to manage a system exposed to higher frequency volatility:

- **Fast frequency response (FFR):** Ireland has enhanced its FFR service by reducing the full activation time requirement from 2 seconds to 1 second, with delivery incentivised in as short a time as 150 milliseconds. This allows assets to respond rapidly (within seconds) to frequency deviations, reducing the need for high inertia levels.
- **Low-carbon inertia services (LCIS)**: the All-Island power system has successfully procured the first phase of LCIS, contracting approximately 11 gigawatt-seconds (GWs) of inertia capacity – 6.9 GWs in Ireland and 4 GWs in Northern Ireland – through synchronous condensers. This covers close to 45% of the All-Island power system's minimum grid inertia needs to 2030, reducing the likelihood of renewable energy being curtailed to enable system services from

conventional fossil-based generation. The tender included a locational element to incentivise bidders to situate themselves in areas most in need of location-based services such as reactive power provision for voltage support. Work on the second phase of LCIS procurement (LCIS 2) has now begun. Subject to a regulatory decision by the SEM Committee, EirGrid expects to launch the process in [Ireland in January 2026](#).

Fast frequency response service provision by technology in Ireland, 2021-2025



Notes: DSU = demand-side unit.
Source: EirGrid, as modified by the IEA.

- **Grid-forming (GFM) controls:** Looking ahead, GFM converters offer promising frequency control potential, allowing VRE generators, battery storage systems, static synchronous compensators (STATCOMS) and HVDC interconnectors to behave more like voltage sources, providing reference signals to the grid and contributing to system stability through self-synchronisation capabilities. Ireland is therefore developing a strategy and roadmap to accommodate GFM capabilities while maintaining safety and reliability.

Voltage management

As illustrated by the Iberian Peninsula blackout of April 2025, maintaining stable voltage is essential for system security. A recent Spanish government report states that voltage instability appears to be the cause of the cascading outages.

However, converter-dominated systems present distinct voltage management challenges. Historically, large thermal and hydro plants have acted as voltage sources, supplying reactive power and maintaining stiff voltage waveforms that were largely unaffected by current variations across the network. Although converter-connected VRE sources can provide voltage support, it is different in nature and extent from that of conventional generation. Without appropriate measures, such as targeted incentives and updated regulatory requirements, voltage support capabilities may be reduced in areas with high renewable power penetration.

Voltage issues tend to be localised, particularly affecting regions with high wind penetration and limited local support from synchronous generation. The government has identified specific concerns in Dublin and parts of southern and northwest Ireland during high-SNSP scenarios. Synchronous condensers procured through the LCIS programme will provide both inertia and reactive power support, helping maintain voltage stability in critical regions.

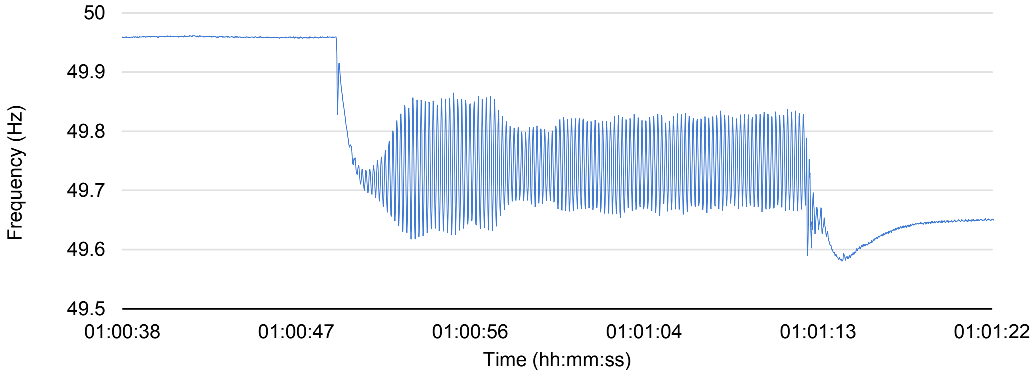
Ireland is also considering the use of GFM converters, flexible AC transmission systems and other solutions for voltage management in areas where traditional methods may be insufficient. To support voltage management, a voltage trajectory tool (VTT) has been introduced in control rooms to optimise the dispatch of devices and systems used to manage voltage and reactive power in the power system.

System oscillations

Oscillations – power fluctuations that can affect system stability – have long been a feature of power systems, even those dominated by traditional synchronous generators. However, in systems with a high share of converter-connected generation, these oscillations can emerge in new ways, for instance from complex interactions between converted-connected resources and traditional synchronous generators. The global relevance of this challenge has been made clear through widespread incidents associated with rapid growth in converter-connected resources, including the South Australia blackout (September 2016), the Great Britain power disruption (August 2019) and grid disturbances in Texas (June 2022).

Ireland has already experienced instances of oscillatory phenomena. For example, an oscillation event in the Irish power system in May 2024 was successfully identified thanks to high-resolution real-time data from phasor measurement units (PMUs) and addressed before it evolved into a serious incident. As these complex interactions might not be detected through traditional simulation tools, system operators need to co-operate with equipment manufacturers and software developers to deploy cutting-edge monitoring and modelling capabilities to predict and prevent such instabilities. These advanced techniques are still emerging, with only a handful of transmission system operators worldwide beginning to invest in such capabilities, and industry standards have yet to be established for their implementation.

Ireland power system oscillation event, 14 May 2024



Note: In the 5-Hz oscillation event that occurred in the Ireland and Northern Ireland power system in May 2024, an initial large-HVDC interconnector infeed loss (530 MW of imports) resulted in an oscillation lasting 20 seconds and involving battery energy storage system (BESS) units. This in turn led to the further loss of infeed (380 MW of imports) from a second HVDC interconnector. The oscillation stopped when the system frequency breached the under-frequency power limiter of the BESS units. System operators were able to identify the oscillations thanks to high-resolution real-time data from phasor measurement units (PMUs) and took remedial action following the event to prevent a reoccurrence.

Source: EirGrid, as modified by the IEA.

The 28 April 2025 Iberian Peninsula Blackout: Lessons and action areas

On 28 April 2025, a total blackout struck the Iberian power system, affecting Spain, Portugal and, briefly, southern France. While restoration was swift thanks to interconnections, black start hydro resources and co-ordinated TSO action, the incident caused significant economic and social disruptions and exposed vulnerabilities relevant to all modern power systems. The blackout offers critical lessons for Ireland, given the similarities between these systems – all are modern, relatively isolated networks increasingly reliant on converter-connected generation.

Official preliminary investigations point to voltage instability as the main cause, despite early speculations that low inertia was to blame. The event began with voltage oscillations, likely linked to a power plant malfunction. The failure of several generators to supply the required voltage support – exacerbated by thermal generation unavailability and outdated grid codes that prevented VRE from providing voltage support – resulted in voltage excursions that triggered cascading generator disconnections. Over 500 MW of distributed generation disconnected without operator visibility, while limited monitoring and data availability hindered the response.

While Ireland's grid characteristics share similarities with the Iberian system, drawing specific lessons would require a dedicated assessment of Ireland's voltage stability and reactive power needs. However, the Iberian experience suggests several areas that warrant investigation for Ireland:

- Grid code modernisation: ensuring that system services can be procured from all assets capable of providing them, including VRE
- System observability: improving monitoring and data availability, particularly for distributed and embedded resources and key substations
- Technologies for voltage stability: evaluating the potential role of technologies such as synchronous condensers and grid-scale batteries to enhance voltage stability and dynamic response capabilities
- Compliance enforcement: assessing voltage support requirements for all grid-connected assets on both the supply and demand sides, considering the significance of large loads in Ireland's system.

This event underscores that voltage stability – not just frequency control and inertia – becomes increasingly critical as renewable energy penetration increases. Ireland's progressive grid codes under the Delivering a Secure Sustainable Electricity System (DS3) and Future Arrangement for System Services (FASS) programmes already enable renewable voltage support, providing a potential advantage. However, the Iberian experience highlights the importance of conducting a comprehensive assessment of Ireland's specific voltage stability and reactive power requirements. Such an assessment would enable targeted solutions and inform the deployment of appropriate monitoring equipment to increase visibility and evaluate the effectiveness of any implemented measures.

Disturbances stemming from large-load behaviour can create significant stability risks

Data centres represent a significant portion of electricity demand in Ireland: over 80 facilities with a cumulative capacity of approximately 2.2 GW accounted for 22% of total electricity consumption in 2024. These facilities are particularly sensitive to voltage disturbances, and their response to grid events can create cascading stability issues. As a relatively small grid with a high number of large energy users (LEUs) geographically clustered in the Greater Dublin area, Ireland is particularly vulnerable to large-load losses arising from voltage disturbances.

International experience highlights these risks. In a July 2024 incident in the US Eastern Interconnection, a transmission line fault led to the simultaneous loss of about 1 500 MW of voltage-sensitive load from data centres. For Ireland, where peak load is about 6 000 MW, such an event could trigger systemwide instability due to the relative size of the disturbance. This could result in faster and deeper deviations in frequency and voltage, reducing the time available for corrective action.

International recognition of large-load stability challenges

The operational impacts of data centres on power systems are being increasingly recognised internationally. A survey by the Electric Power Research Institute found that utilities, primarily in North America, are experiencing various operational challenges from existing data centres, with fault ride-through issues reported by 9% of the 23 respondents, along with other concerns such as ramp rate issues (26%), thermal violations (22%) and voltage violations (17%).

The reliability risks associated with the voltage ride-through characteristics of data centre loads are now acknowledged as critical concerns that extend beyond data centres to other large loads. However, comprehensive-fault ride-through requirements specifically tailored to large-demand facilities are still emerging as standards internationally, with Ireland positioning itself as a frontrunner in establishing the technical requirements for data centres and similar power consumers.

Ireland's response to large-load stability risks

Similar to other jurisdictions, EirGrid has proposed technical standards that require high-demand facilities, including data centres and electrolysers, to ride through faults – similar to requirements already established for generation facilities. These standards, which complement other system-level solutions such as procurement of inertia and fast-acting reserves, aim to prevent the automatic disconnections that can trigger systemwide frequency deviations and stability issues.

Dynamic data centre behaviour during system faults

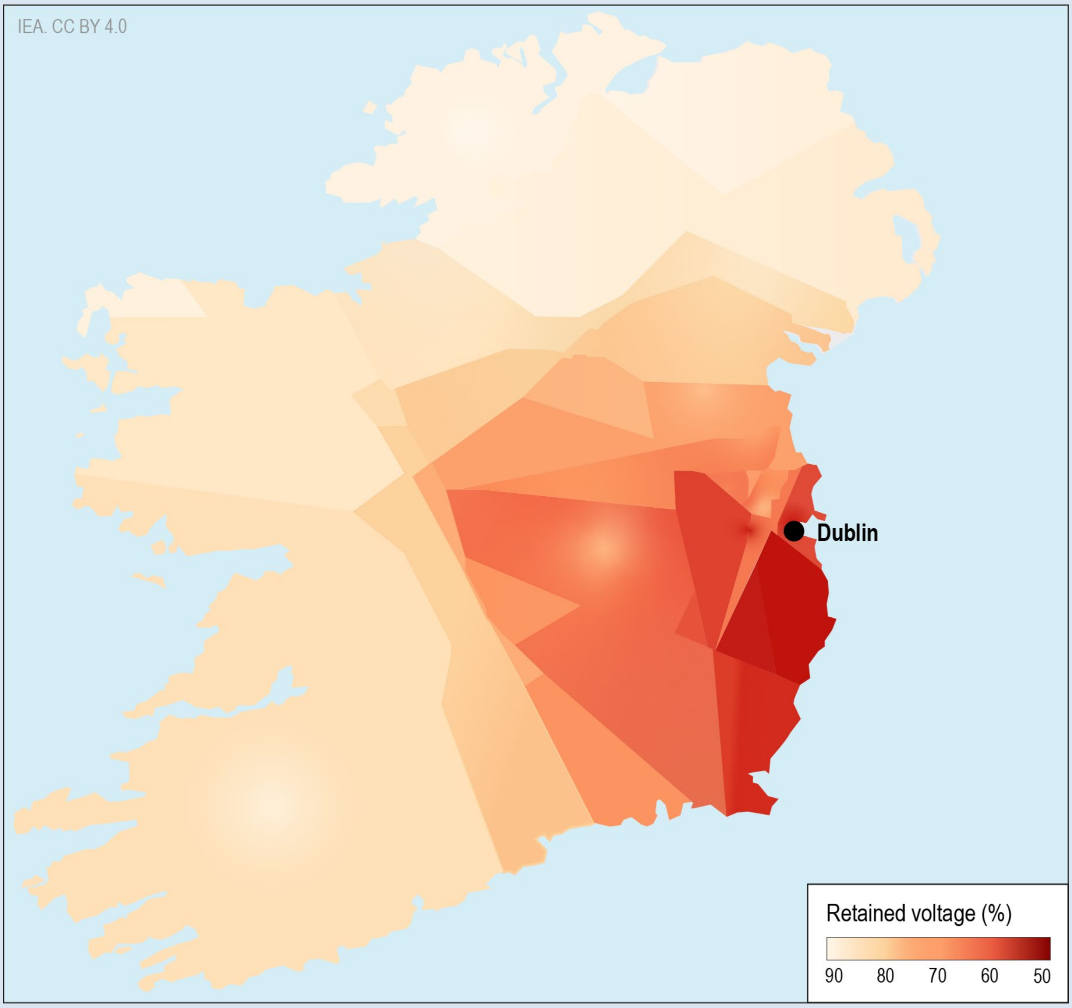
Transmission equipment faults can result in severe voltage dips that propagate across wide areas of the power system. These faults are normally isolated extremely quickly by high-speed transmission protection equipment, allowing voltage to recover to normal operating range within tens of milliseconds. Most power system users have the capability to ride through (i.e. not trip off) during these transient events.

However, many data centres behave differently by design. During faults, some data centre loads automatically disconnect from grid supply and switch to internal backup battery systems as part of built-in protection settings designed to safeguard sensitive IT equipment. This results in demand reduction that can persist for tens of seconds until the data centre's system deems the grid stable.

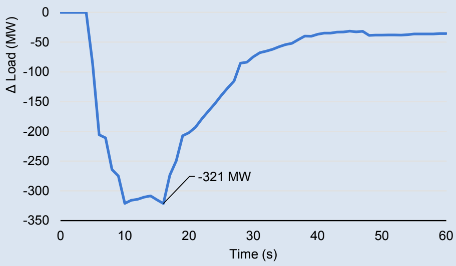
This creates a demand-supply imbalance that can lead to significant systemwide frequency deviation. An example of this occurred on 26 January 2025, when a fault in Dublin triggered a collective data centre response, demonstrating how voltage disturbances can cascade into frequency stability issues.

System frequency/RoCoF and collective data centre response to 220-kV fault in Dublin, 26 January 2025

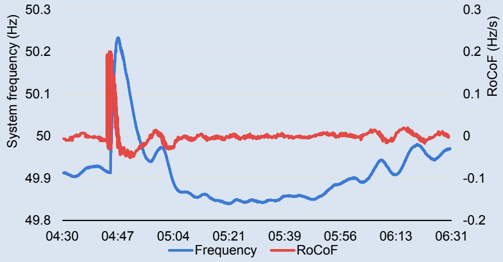
Voltage disturbance propagation



Collective data centre power response



Frequency and rate of change of frequency impact



Note: RoCoF = rate of change of frequency.

Source: EirGrid, as modified by the IEA.

New system service sources will be needed as renewables displace conventional generators

As VRE and imports from HVDC interconnectors displace conventional generators, essential services such as frequency control, voltage regulation and inertia can no longer be taken for granted as byproducts of electricity generation. This evolution is driving comprehensive changes in how power systems procure and value system services, with traditional market designs often not capturing the full value offered by VRE, storage technologies and demand response.

Evolution of system services

As the provision of system services evolves, complex regulatory, technical and economic challenges arise. While technological solutions to maintain stability exist, deploying them successfully requires a fundamental paradigm shift in system operations, planning and financing. The transition involves navigating regulatory frameworks not designed for these new services, developing market mechanisms that properly value stability contributions, and managing the technical risks of operating systems in unprecedented ways.

Several critical uncertainties will shape Ireland's system-services evolution, including the effectiveness of demand-side flexibility, the successful mobilisation of large energy users (particularly data centres) to provide flexible demand-response services, and whether low-carbon inertia services will be sufficient to entirely replace the grid services offered by conventional generation by 2035.

New services such as FFR, synchronous inertial response and ramping margins are being developed internationally to address challenges associated with high levels of variable, non-synchronous generation. At the same time, existing system services must evolve to remain effective under changing system conditions, ensuring they can continue to support reliability in more dynamic and less predictable operating environments.

Grid codes require continuous revision to define minimum standards for how generation assets react to system disturbances while market designs evolve to properly value and remunerate these services through targeted procurement mechanisms. Notable international examples include the Great Britain Stability Market and Stability Pathfinder programmes, which are emerging approaches to ensure system stability in high-VRE environments.

However, this transition faces significant implementation challenges. Regulators must approve the provision of these new services that may fall outside of their traditional mandates, requiring potential legislative changes. Finding the right balance between mandatory grid code requirements and competitive market procurement involves complex trade-offs between system security and cost-effectiveness. Additionally, ensuring compliance with evolving requirements is as critical as the requirements themselves, particularly when retrofitting existing assets can be prohibitively expensive.

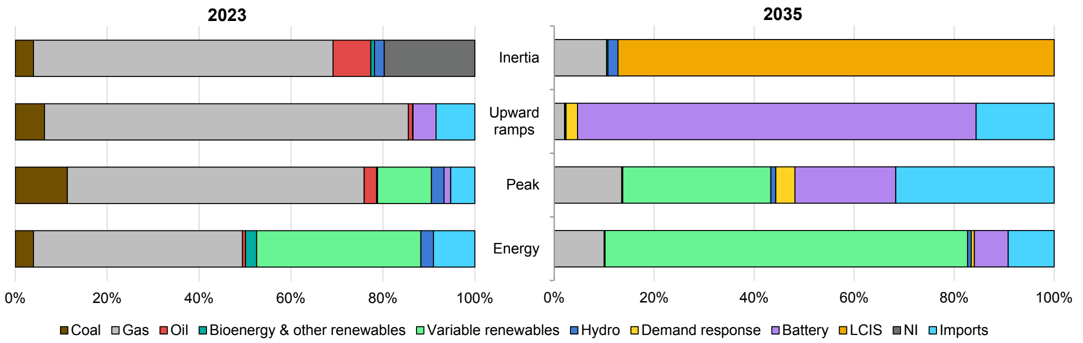
Ireland has positioned itself at the forefront of this transition through its pioneering Delivering a Secure Sustainable Electricity System (DS3) programme, which was launched in 2011 and has successfully facilitated high renewable energy integration. The DS3 framework has procured 12 system services from diverse providers, including conventional generators, wind farms, interconnectors, battery storage and demand-side response systems.

Furthermore, the country is now implementing the Future Arrangement for System Services (FASS) programme to replace the DS3, introducing significant advances and aiming to eventually use daily auctions to procure system services. The programme includes a layered procurement framework for medium-term contracts (up to 12 months) to reduce barriers for new technologies, scheduled to be operational in 2027. The FASS programme is being implemented with the target of enabling up to 95% instantaneous system non-synchronous penetration (SNSP) by 2030. These advances add to development of the LCIS scheme to procure inertia services.

Through the EirGrid and SONI Operational Policy Roadmap 2025-2035, Ireland is also implementing fundamental operational policy changes to increase procurement of advanced system services. Developments include transitioning from a single All-Island inertia floor to regional inertia models for Ireland and Northern Ireland; introducing comprehensive system-strength policies with real-time monitoring metrics; and designing frameworks to manage low short-circuit levels in weak network areas.

These policy changes are designed to enable the procurement and valorisation of system services from a much broader range of technologies, moving beyond traditional reliance on conventional generation. The contribution of various technologies to system services is expected to shift dramatically between 2023 and 2035, with the share of conventional generation shrinking for most of these services, including inertial response, upward ramps, peak demand and even energy provision.

Contribution to energy, flexibility and adequacy services by technology in Ireland in the IEA Adapted Transition Pathway, 2023 (left) and 2035 (right)

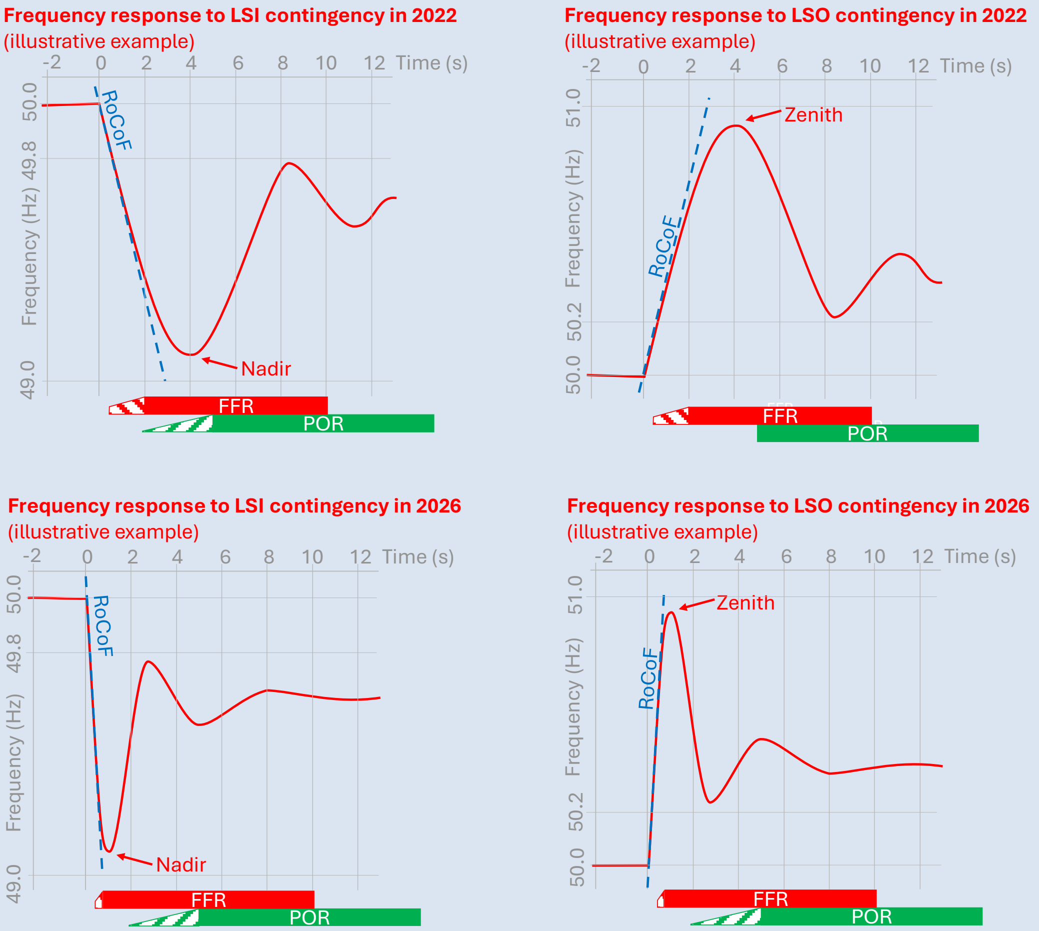


Notes: LCIS = low-carbon inertia services (this bar indicates inertia provided by non-energy units procured through the Low Carbon Inertia Services programme). NI = Northern Ireland (this bar represents inertia provided by plants in Northern Ireland in 2023 to meet the All-Island inertia floor requirement). "Inertia" values include both Ireland and Northern Ireland; other categories cover Ireland alone. Inertia is calculated as the inertia required to meet the 23-GWs inertia floor, i.e. the first 23 GWs in merit order in each hour of the year. "Upward ramps" represents ramping energy provided during the 100 largest upward residual load ramps of the year. "Peak" is energy provided during the 100 highest peaks of the year. "Energy" is the total energy provided over the year. Values for 2035 are based on the IEA Adapted Transition Pathway scenario.

New reserve services for the All-Island power system

EirGrid and SONI recently completed a detailed review of reserve services to address evolving risks such as over-frequency events, the more regular occurrence of frequency extremes and higher rates of change of frequency. Over-frequency events are likely to become more frequent with the proliferation of data centres and other large-load connections, as well as increased interconnection capacity.

Frequency responses to infeed and outfeed contingencies in Ireland, 2022 and 2026



Notes: LSI = largest single infeed. LSO = largest single outfeed. FFR = fast frequency response. POR = primary operating reserve. RoCoF = rate of change of frequency.

Source: EirGrid.

New downward reserve products have been developed that mirror the existing upward products. The fast frequency response (FFR) service has been modified to reduce the full activation time from 2 seconds to 1 second, reflecting changing power system needs. New reserve volume requirements are based on the "reference incident" – the sum of the largest single infeed/outfeed and any associated consequential losses.

Looking ahead to 2035

In 2035 in the IEA Adapted Transition Pathway scenario, gas-fired generators – in addition to providing energy to complement renewable power generation – retain an important role in providing system services such as inertia, voltage support, and fault current and oscillation-dampening capabilities. Assuming that a second LCIS tender is held and that it procures similar quantities by 2035, Ireland would have close to its minimum inertia level supplied by low-carbon services. Depending on how these services are scheduled and dispatched, they could be providing the vast majority of inertia by 2035.

A key operational question will be whether low-carbon inertia services will be sufficient to entirely replace the grid services offered by conventional generation by 2035. Although technologies such as synchronous condensers and the grid-forming operation of converter-connected resources can provide system services, it is unclear whether these services alone would be able to support a system without conventional generation, while gas-fired generation will still be needed to provide energy and reserves at some times of the year.

Ireland's proactive approach to stability management – combining innovative technologies, enhanced monitoring systems and adaptive operational policies – positions the country as a valuable testbed for the global energy transition. The lessons learned from Ireland's experience will prove invaluable for systems around the world that are pursuing similar decarbonisation goals while aiming to enhance their electricity security.

Climate resilience and cyber security

Having examined operational security challenges in the previous section, this section addresses the physical infrastructure dimension of resilience, recognising that robust transmission and distribution networks are prerequisites for implementing the advanced operational measures discussed earlier. Ireland's power system is facing broad resilience challenges from both environmental factors and digital vulnerabilities.

First, the risks associated with ageing power system infrastructure are being exacerbated by growing pressure from extreme weather events, which can lead to significant damage and power outages, in many cases affecting rural communities for the longest periods. At the same time, the expansion of power system digitalisation is creating cybersecurity risks that require proactive management. Thus, in mitigating climate and cyber risks, policymakers will need to assess trade-offs between acceptable levels of risk and the costs of securing the system, as a zero-risk power system may be prohibitively expensive or technically unfeasible.

Extreme weather events increase ageing electricity grid infrastructure risks

Ireland's power system infrastructure is under growing pressure from the combination of ageing and more frequent extreme weather events. For instance, the Environmental Protection Agency's National Climate Change Risk Assessment identified disruption and damage to the energy system from extreme winds as a priority concern requiring urgent action within the next five years.

The scale of Ireland's infrastructure challenge is substantial. Without intervention, 57% of its high-voltage stations will be more than 60 years old by 2040, while the distribution network comprises approximately 165 000 km of lines – four times the EU per-capita average. This extensively rural distribution network, with its high ratio of overhead to underground lines, is very vulnerable to weather-related disruptions.

ESB Networks is therefore implementing a comprehensive risk-based asset maintenance and replacement programme designed to physically harden the system against extreme weather. The programme focuses on several key areas: upgrading high-voltage stations with weather-resistant equipment and flood protection measures; systematically replacing vulnerable wooden poles with more durable concrete or steel alternatives that can better withstand high winds; strengthening overhead lines and conductors to reduce the risk of failure during storms; and implementing more extensive vegetation management to minimise tree-related outages, which were a major cause of damage during Storm Éowyn.

Additionally, the programme includes installing automated devices and smart grid technologies on the medium-voltage network that can automatically isolate faulted sections and restore power to unaffected areas, significantly reducing both outage frequency and time required for restoration. While selective undergrounding of critical distribution lines in the most vulnerable areas is also being considered, the extensive rural nature of Ireland's network makes comprehensive undergrounding prohibitively expensive.

Recent experience highlights the system's vulnerability: Storm Éowyn in January 2025 damaged 3 000 electricity poles and 900 km of conductor cable, leaving some customers without power for over two weeks. Climate projections indicate these challenges will intensify, with winters becoming up to 24% wetter by 2050 and storm activity increasing.

Impacts of recent extreme weather events on Ireland's energy infrastructure

Event	Electricity networks	Power plants (gas, wind and solar PV)
Flood (2011)	Power disruption to 1 200 customers due to preventative power shutoff	
Hurricane-force Storm Darwin (2014)	Power disruption to 260 000 customers due to faults at high-voltage substations	
Storm Ophelia (2017)	Power disruption to 300 000 customers due to destruction of electricity poles and cables	Preventative reduction of wind generation
Storm Ellen (2020)	Power disruption to 200 000 customers due to destruction of power lines	
Storm Barra (2021)	Power disruption to 59 000 customers due to trees falling on overhead lines	Preventative partial shutdown of wind turbines
Storm Eunice (2022)	Power disruption to 80 000 customers due to tripping of 110-kV transmission line	Collapse of one of three CCGT unit stacks at Grain power station; solar panels ripped off roofs
Heatwave (2022)	Less-effective power stations and transmission lines	
Storm Isha (2024)	Power disruptions to 235 000 customers due to fallen power lines	
Storm Éowyn (2025)	Power disruption to 768 000 customers due to damage to 3 000 electricity poles and 900 km of conductor cable	Collapse of a wind turbine; preventative reduction of wind generation

In the short term, ESB Networks has responded with a comprehensive Winter 2025 Grid Resilience Plan that includes enhanced vegetation management, strategic deployment of mobile generation units and the accelerated replacement of vulnerable wooden poles with more durable alternatives. However, utility providers acknowledge that no network in the world can withstand gusts of 180 km/hour, and that utilities cannot be fully climate-proofed.

This reality emphasises the need for a balanced approach that combines infrastructure hardening with improved emergency response capabilities. Ireland's challenge lies in determining what level of resilience is realistic from both technical and cost perspectives while ensuring the grid can support the country's multiple goals of decarbonisation, economic growth and housing development through 2035.

In terms of policy action, the National Emergency Co-Ordination Group has launched a cross-government Review of the Response to Storm Éowyn, examining the co-ordination of local measures with the national-level whole-of-government response. The government is also pursuing legislative changes to address one of the primary causes of Storm Éowyn's damage – fallen trees across power lines.

In addition, the DCEE is currently updating the Electricity and Gas Networks Sectoral Adaptation Plan, the main mechanism for achieving energy sector resilience. The revised plan, which was presented for public consultation in August 2025, includes an assessment of current and future climate risks for electricity transmission, distribution and generation, and will set out key actions to make Ireland's energy networks more resilient.

Rural communities face heightened vulnerability to prolonged power outages

Because of Ireland's unique settlement pattern, rural communities are affected disproportionately during extreme weather events. The country's legacy of one-off rural housing means it has four times the EU per-capita average in distribution lines. This extensive overhead network, combined with high exposure to forestry-related damage, creates systemic vulnerability.

Storm Éowyn demonstrated these vulnerabilities acutely. While urban areas typically experienced outages of hours or days, many rural communities remained without power for over two weeks. Forests cover approximately 11% of Ireland, of which more than 80% correspond to coniferous plantations that are particularly vulnerable to wind damage due to their height and shallow root systems. It became clear during Storm Éowyn that it is essential to plan afforestation in a way that does not threaten electricity infrastructure, as fallen trees were a major cause of power outages. ESB Networks has identified 710 km of forestry corridors requiring enhanced management and is working with Coillte and the Department of Agriculture, Food and the Marine to address sections of the network at highest risk of further windfall damage.

The potential consequences of extended outages can become more severe if the transition to electric heating systems in rural communities is not accompanied by sufficient measures to improve resilience. Remote communities often experience prolonged outages during extreme weather events, with some areas remaining without electricity for over a week after major storms. This vulnerability could be exacerbated by increasing dependence on electricity as rural heating transitions from fossil fuel-based systems to electric technologies, with limited alternative supply options if grid connections fail.

International research has identified several effective ways to enhance resilience in rural communities while continuing to expand electrification, including investing in grid modernisation (e.g. targeted undergrounding of critical lines), strategically managing vegetation and developing localised generation and storage capabilities. However, the dispersed nature of Ireland's rural housing creates inherent challenges that energy infrastructure solutions alone cannot fully address.

Ireland can look to international experience and co-operation to enhance resilience

Countries worldwide have developed innovative approaches to make their electricity infrastructure more resilient to extreme weather. For instance, Sweden's response to Storm Gudrun in 2005 included amending its Electricity Act to require power generators to restore service within 24 hours or face substantial financial penalties, creating a strong economic incentive for distribution system operators to invest in resilience. Meanwhile, Finland has pursued ambitious underground cable deployment, sharing costs with telecommunications providers and realising economies of scale.

Interestingly, the United Kingdom maintains dedicated submarine cable repair capabilities through contracted access to specialised vessels, enabling rapid responses to undersea infrastructure damage. This contrasts with other regions where restricted commercial vessel availability can cause repair mobilisation times to exceed four months. Ireland's increasing reliance on submarine interconnectors means that it will need similar rapid repair capabilities.

International experience also suggests that co-operation through mutual storm support arrangements with neighbouring countries, the sharing of specialised equipment for cable repairs and co-ordinated early warning systems can boost power system resilience.

The longer-term impacts of climate change will require proactive planning and adaptation

Climate change is likely to increase Ireland's seasonal variations in precipitation, leading to drier summers and more frequent heavy precipitation events in autumn and winter, increasing the risk of floods. It is also expected to decrease wind speed during the summer and alter storm characteristics. While storms are projected to become less frequent overall, the intensity of extreme windstorms may increase. Adapting to these changes will require proactive planning and management.

Coastal infrastructure is particularly vulnerable in the long term. Ocean surface temperatures in Irish waters have climbed approximately 0.6°C per decade since 1994. At the same time, rising sea levels and coastal erosion threaten the submarine cable landings, coastal substations and offshore wind infrastructure that will form the backbone of Ireland's future electricity system.

To adapt to coastal erosion in particular, new data collection and enhanced mapping are needed to better understand coastal vulnerabilities and to identify the coastlines most at risk from future erosion and flooding. This information is essential to inform coastal management plans and support actions to strengthen the resilience of critical coastal infrastructure. An interdepartmental steering group, led by the Department of Housing, Local Government and Heritage (DHLGH) and including DCEE as a member, is currently addressing coastal change management.

Increasing power system digitalisation creates new cybersecurity vulnerabilities

The growing use of digital control systems across Ireland's power system raises its potential exposure to cyber threats. Globally, attacks against utilities more than doubled between 2020 and 2022, making it clear that new security challenges arise when critical system operations rely increasingly on networked technologies. Indeed, the 2021 cyberattack on Ireland's Health Service Executive (HSE), which resulted in considerable personal data leaks, demonstrated the country's vulnerability to sophisticated cyber threats.

A particularly concerning trend is the rise in supply chain attacks, wherein attackers exploit the cybersecurity vulnerabilities of affiliated companies, business partners or contractors to infiltrate target systems. US research shows that nearly half of energy sector cybersecurity breaches originate with third-party vendors.

Ireland has established regulatory requirements for cybersecurity through its National Cyber Security Strategy, and for the designation of electricity operators under the EU Network and Information Systems (NIS) Directive and its replacement, the NIS2 Directive. International experience suggests that protection could be enhanced through the enforcement of mandatory cybersecurity standards for all energy sector suppliers and the continuous monitoring of vendor cybersecurity.

Chapter 5. Policy recommendations

From challenges to policy action

Ireland has positioned itself as a leader in renewable energy integration and power system modernisation. These achievements lay a strong foundation for the decade ahead, which will be marked by rapid change and increasingly complex demands on the power sector. As electricity will play a central role in Ireland's broader national decarbonisation, housing expansion, digitalisation and economic development goals, it is essential for the country to have a secure power system.

Thus, as this report has shown, Ireland will have to make some important strategic decisions as it enters the next stage of its energy transition, taking several evolving dynamics into consideration:

- Electrification, housing development and economic activity are driving strong increases in electricity demand. Infrastructure expansion must keep pace while maintaining system reliability.
- Additional measures will be required to accelerate renewable energy deployment, to avoid potential unintended reliance on imports and storage in the 2030s.
- Continued attention will be needed to avoid delays in grid development, which is central to both demand growth and renewable power generation.
- In the Adapted Transition Pathway results, reliance on interconnection and storage to meet peak residual load in 2035 warrants a more detailed adequacy assessment. Secure operations under IEA modelling are feasible but rely on the timely delivery of storage, interconnection capacity and domestic generation. To decide on adequate thermal generation levels, it will be necessary to weigh the benefits of new security-oriented capacity against the lock-in risks of new thermal generators.
- To safeguard secure operation under a high renewable penetration, capabilities and frameworks not yet covered by current international practice will be required.

The assorted challenges these distinctions entail cannot be addressed in isolation. Securing Ireland's electricity system to 2035 and beyond will require co-ordinated action across all sectors and policy domains: faster infrastructure delivery; clear long-term signals for electricity supply alternatives; and enhanced operational capabilities to manage high renewable penetration.

It will also require stronger alignment of electricity system development with broader national priorities, including decarbonisation, economic development and housing expansion. As Ireland currently lacks an integrated framework that links power system planning to cross-sectoral objectives, its ability to manage emerging trade-offs, prioritise infrastructure and ensure timely delivery is limited.

The following five policy pillars therefore provide an integrated framework for Ireland to enhance its energy security to 2035 while pursuing its multiple policy goals. Each pillar addresses a core dimension of the challenges discussed in this report, and together they provide a pathway for Ireland to enhance its energy security in the coming decade.

Five pillars for policy action

To ensure energy security through 2035 by tackling the needs identified in this report, Ireland should:

- Establish a **cross-sectoral energy security strategy for the 2030s** that details a coherent long-term vision underpinned by cross-sectoral co-ordination, using an energy security lens to identify infrastructure needs and devise a medium-term roadmap for their delivery.
- **Develop enabling infrastructure** such as grids, taking account of long lead times and the critical role of infrastructure to enable generation and demand growth and enhance climate resilience.
- **Expand generation capacity, storage and demand-side flexibility** to ensure sufficient resources to meet adequacy and flexibility needs.
- **Enable secure operations under a high renewable penetration**, ensuring that all conditions are met to operate the system safely and efficiently.
- **Advance workforce skills, strengthen partnerships and facilitate electrification**, key cross-cutting domains that underpin progress in electricity security and several other of Ireland's ambitions.

Establish a cross-sectoral vision for the 2030s

Ireland does not yet have a unified framework to align power system development with its national climate, economic and societal goals under a coherent long-term vision. As it enters a decade of rapid change and rising electricity demand, the absence of a co-ordinated, forward-looking strategy could entail risks of delivery gaps, inefficient investment and growing tensions among policy ambitions.

While Ireland's Climate Action Plan sets out detailed targets for individual sectors (e.g. for renewable electricity, heat pumps and electric vehicles), they are not fully integrated with other key electricity demand drivers, including housing expansion, economic growth and data centre development. In response to these targets, sectoral stakeholders such as ESB Networks and EirGrid have developed roadmaps to guide infrastructure and service planning, for example to meet the

80% renewable supply target by 2030. However, these efforts remain fragmented and are weakened by a lack of consolidation under a single national strategy.

Develop a holistic cross-sectoral energy security strategy for the 2030s. As there is currently no overarching vision that consolidates sectoral efforts, sets clear priorities or evaluates potential trade-offs, reaching consensus on such a strategy through strategic stakeholder co-operation can ensure that the power system develops in alignment with broader national goals while safeguarding energy security and affordability. After establishing this vision, the strategy needs to identify challenges and risks beyond 2030 and set out immediate priority actions to ensure energy security, bridging the gap between the existing policy framework for energy security to 2030 and longer-term targets from 2040.

To deliver on its comprehensive vision, this strategy should establish clear infrastructure necessities, identified through an exhaustive system-needs and adequacy assessment. Such an exercise should quantify requirements across generation, storage, demand flexibility, electricity networks and cross-border interconnectors. These assessments should evaluate resource adequacy under stress scenarios, map regional system service needs, and identify critical interdependencies between electricity and gas systems during the transition period.

Such analysis will help align development efforts. Co-ordination between the power and end-use sectors (e.g. services, transport and buildings) is essential to obtain a clear overview of demand-side developments, creating an integrated approach that supports energy security while advancing achievement of Ireland's energy and climate goals.

As natural gas use evolves, the country will also need measures to ensure electricity capacity adequacy while reducing fossil fuel import reliance and working to reach decarbonisation targets, and to mitigate gas supply risks while it is transitioning to lower gas use. Although lowering fossil fuel dependency will not be easy, it would reduce the economy's exposure to volatile global fuel prices and supply disruptions, particularly during periods of geopolitical instability.

A broad and co-ordinated strategy will therefore be required to scale up low-emissions domestic electricity generation, improve energy efficiency, encourage behavioural shifts and accelerate the electrification of fossil fuel-intensive end uses such as heating and transport. Setting intermediate power sector targets for 2035 can provide structure for progress, ensuring advancement towards a secure and sustainable all-energy system.

Strengthen integrated system planning mechanisms, to be used when creating the strategy and for regular planning exercises outside of it. To establish unified system development – aligned within and across government institutions

– Ireland should implement energy-sector-wide planning to address more than just single-purpose scenarios in individual areas such as adequacy, emissions or long-term variable renewable energy (VRE) targets. Ireland could draw on the integrated approach to gas and electricity network planning ENTSO-E uses for its Ten-Year Network Development Plans to give consistent direction on trade-offs between gas and electricity network connections, which could help inform some decisions on data centre projects.

Planning should build on the recent gas disruption exercise carried out in Ireland to identify risks to gas supply, notably the interconnector with Great Britain, and propose mitigation options. Beyond plant outage patterns, system planning can incorporate robust scenario analysis and extreme weather events, drawing on Australia's Integrated System Plan, which looks 20+ years ahead. Ireland should ensure that integrated planning exercises co-ordinate grid expansion with demand/generation spatial planning to map out regional system service needs and areas where new demand can ease VRE integration.

Develop enabling infrastructure

Once a cross-sectoral energy security strategy and system needs assessment are in place, the next critical step is to ensure that enabling infrastructure is delivered at pace to meet Ireland's energy targets. Such infrastructure will lay the foundation for Ireland's growth trajectory and is a precondition for generation capacity, storage and demand flexibility development. The central focus must be on electricity grids, though other infrastructure such as port capacity should not be neglected.

Grids are essential to integrate growing volumes of renewable energy, support a rising population and economic base, and enable the electrification of transport, heating and industry. As their role expands, so too does the urgency of addressing long permitting wait times, supply chain constraints and rigid regulatory frameworks that could delay critical grid expansion and limit the use of existing assets. Sustained investment in grid resilience will also be vital to ensure the system remains robust in the face of growing complexity, demand and climate impacts (e.g. from extreme weather).

Improve the existing anticipatory and flexible investment frameworks to ensure timely and cost-effective grid expansion. To meet Ireland's growing electricity demand amid forecast uncertainty, investment planning must be both proactive and adaptable. Building on ESBN's Build Once for 2040 strategy and the Agile Investment Framework used in CRU Price Reviews, the government could consider extending regulatory periods to support longer-term planning while preserving flexibility through agile mechanisms. It also needs to decide whether the time horizons over which investments are valued set the appropriate incentives for long-term action.

Furthermore, regular joint reviews involving EirGrid, ESBN and the CRU should be established to identify and prioritise high-impact grid projects with robust investment cases. Developing standardised procurement frameworks can streamline delivery, reduce costs and accelerate implementation.

Strengthen supply chains and establish a transparent project pipeline for grid infrastructure delivery. To avoid delays and disruptions in the deployment of grid infrastructure and other enabling systems, Ireland could adopt proactive supply chain strategies. For increased transparency, it could publish a list of grid projects in the long-term pipeline to support early procurement and provide visibility to suppliers. Long-term investment planning should explicitly assess supply chain risks and promote alignment across the grid and generation ecosystem.

To enhance supply chain resilience, the government should support diversification and regional co-operation, for example by exploring joint procurement platforms and strategic EU partnerships. Harmonising procurement procedures can streamline sourcing and improve interoperability, while regulatory flexibility can reduce lead-time risks. To future-proof investments, cybersecurity and sustainability standards should be embedded in procurement processes. Furthermore, while strategic reserves or buffers are costly, they could be established to mitigate exposure to geopolitical and supply-side shocks.

Update the regulatory framework to incentivise the deployment of grid-enhancing technologies. To unlock additional capacity on Ireland's increasingly congested grid, the government should prioritise the deployment of grid-enhancing technologies (GETs) such as dynamic line rating, power flow control and topology optimisation, particularly where they offer the greatest system value. While the expansion of GETs should happen in tandem with infrastructure buildout, they can deliver faster, lower-cost capacity gains.

Additionally, in collaboration with the CRU, the government should ensure that the regulatory framework actively incentivises GET adoption when it is cost-effective. Performance-based regulation models could be adopted, drawing on international best practices from Australia, Italy and Great Britain, where grid operators are given incentives to deliver measurable grid efficiency and reliability improvements.

Improve the permitting process to speed up grid infrastructure delivery. With the landmark Planning and Development Bill 2023 now passed, Ireland must focus on its effective and timely implementation to ensure the planning system delivers clarity, consistency and certainty for expanding grid infrastructure. This includes enforcing statutory timelines, resourcing planning authorities and rolling out digital systems to streamline applications. Permitting processes should also be simplified for lower-impact upgrades such as reconductoring, which can significantly enhance grid capacity with minimal disruption.

When appropriate, Ireland can draw on the "overriding public interest" principle to fast-track permitting for key grid projects to connect renewables. To further improve the planning regime, the government can build on international best practices such the Netherlands' National Grid Congestion Action Programme (LAN), which includes legal reforms, policy measures, stronger central co-ordination and streamlined processes at TenneT to shorten permitting procedures for electricity infrastructure by several months to years.

Upgrade infrastructure for physical resilience. Without targeted resilience investments, Ireland's energy system remains vulnerable to climate impacts, physical threats and electricity supply disruptions. The government should consider basing decisions on the principle that resilience often requires redundancy, which may seem inefficient until tested by a crisis. Redundancy in key network nodes, such as those for the Greater Dublin area, should be prioritised.

Building on the National Climate Change Risk Assessment and the upcoming Sectoral Adaptation Plan for Electricity and Gas Networks, the country should develop a plan to improve power sector resilience. It should also invest in climate-adapted specifications for new transmission assets, especially offshore wind, to withstand extreme weather. Furthermore, the physical security of HVDC interconnectors and submarine cables needs to be enhanced, and the government could explore joint repair arrangements with neighbouring TSOs. To ensure adequate power for critical loads and rural communities, Ireland should expand the use of existing distributed energy resources and enable islanding capabilities.

Expand generation capacity, storage and demand-side flexibility

After formulating a means to expand enabling infrastructure, Ireland needs to focus on developing the energy resources identified through holistic strategy and system planning. As electricity demand evolves, driven by electrification, population and economic growth, and data centre expansion, generation assets need to follow to ensure demand can be met securely and affordably.

To meet the government's decarbonisation goals, most additional capacity will be renewables-based, introducing new system stability, adequacy and flexibility challenges. To safeguard reliability during periods of system stress, Ireland will need to procure sufficient dispatchable generation, but it is also crucial to scale up storage development and enable demand-side flexibility, not only to respond to inherent renewable energy variability but also to provide key system services.

Generation

Improve permitting processes for renewable energy deployment. Ireland is a key example of a country with robust participatory mechanisms where community engagement is promoted from the early stages of project development. However, other tools are also available to further increase and accelerate permitting for renewable energy projects.

Legal and digital tools can be utilised to improve permitting processes. For example, the overriding-public-interest principle can be a powerful instrument but implementing it may require changes to other parts of a country's legal framework. For Ireland, past court rulings show that the principle cannot be applied automatically, as it can create conflicts with other legal principles, especially those related to environmental protection. Addressing this challenge will require a tailored approach and a comprehensive assessment of all legal implications. Digital tools, such as the United Kingdom's AI-powered Extract tool and the ACCORD cross-country digital platform that are currently being piloted, could be implemented in Ireland to help accelerate permitting processes.

Accelerate the designation of renewables acceleration areas (RAAs). The EU 2023 Renewable Energy Directive requires member states to designate RAAs – zones where renewable energy projects can be developed faster and easier, thanks to a streamlined permitting and environmental assessment process. Countries can use several tools to accelerate RAA identification: for example, strong collaboration between national and local authorities and improved co-ordination among all stakeholders is essential to ensure consistency with EU-level renewable energy targets, as well as with European environmental legislation.

Moreover, one-stop shops can significantly streamline developer-administration interactions by designating a centralised authority to handle permits and act as a single contact point for developers. In parallel, authorities should invest in tools and infrastructure to digitalise the permitting process, raising administrative efficiency at all levels. Spain and Portugal have both demonstrated success by using digital tools to exhaustively map renewable energy potential and suitable areas for deployment.

Encourage renewable energy investments by leveraging the security offered by market frameworks and contractual arrangements. Ireland can promote renewable energy investments by providing predictability through long-term auction schedules and volumes, and by leveraging public and private contractual security. To derisk and facilitate the efficient development of large renewable energy projects (e.g. offshore wind), the government should consider establishing a clear timeline of auctions for the upcoming 5-10 years, with details on volumes per auction.

Auctions and contracts (such as two-way contracts for difference) should also be designed to account for specific industry risks, such as supply chain constraints, and should safeguard incentives to operate and participate efficiently in electricity markets, in line with EU regulations. As corporate power purchase agreements (CPPAs) covered just 16% of additional data centre demand between 2020 and 2023, the government can consider developing an enabling framework to expand CPPA use to support renewable energy development and emissions targets. For instance, it could remove existing barriers. In addition, clear reporting standards could increase transparency and support CPPAs that deliver additionality, hourly matching or CO_2 reductions.

Ensure the procurement of security-oriented capacity through an updated, flexible capacity framework. As Ireland works to decarbonise its power system, it must ensure that sufficient dispatchable generation, particularly gas-fired, remains available to safeguard system adequacy. It should determine how much capacity is needed through a comprehensive forward-looking assessment that accounts for peak demand, renewable energy variability and system resilience requirements.

Greater reliance on gas for adequacy increases exposure to global gas market shocks and to physical disruptions to the gas interconnector with Great Britain. With the capacity factor of large gas-fired plants expected to fall significantly (to around 12% by 2035 in the Adapted Transition Pathway scenario), Ireland's current Capacity Remuneration Mechanism (CRM) will need to evolve to keep essential capacity financially viable despite reduced market revenues. This could be achieved by adapting the CRM to offer longer-term contracts for new or refurbished thermal assets while maintaining shorter terms for emerging technologies.

Additional support could come from expanding or complementing existing and planned mechanisms, such as the FASS programme, to reward critical system services such as black start, voltage support and fast ramping. To preserve technology neutrality in line with EU rules, any differentiated treatment should be transparently linked to the provision of system-critical services. This approach would ensure that dispatchable assets remain commercially viable to serve as grid anchors while enabling technology diversity to boost system security.

Storage

Accelerate the deployment of battery storage by strengthening investment signals, removing regulatory barriers and aligning market design with system value. While the Electricity Storage Policy Framework sets a strong course for action, deployment must happen more quickly to meet Ireland's near-term flexibility needs. The country should enable full market participation for storage assets across energy, capacity and system services markets, and remove any remaining regulatory barriers such as double taxation or unclear licensing rules.

To unlock investment, Ireland could introduce targeted storage auctions to fulfil specific needs, taking inspiration from Italy's approach, which provides clear procurement volumes and timelines. Continued balancing and dispatch market framework reforms will also be essential to ensure that storage is rewarded for the full range of services it provides, including fast response, congestion relief and system balancing.

Establish a clear market pathway for long-duration energy storage (LDES), considering a dedicated investment framework. To meet its 2028 target for a route to market, Ireland should urgently implement its Electricity Storage Policy Framework actions, starting with a robust assessment of the quantity of LDES needed and the financial support required. As determining quantity requirements several years in advance involves uncertainty about future system conditions, the assessment should consider flexible or probabilistic approaches.

To provide investor confidence while maintaining cost control, Ireland can draw from early examples of LDES support schemes: the planned UK cap-and-floor model offers a stable revenue range without fully shielding projects from market signals, while Italy's MACSE demonstrates flexibility through revenue stacking and locational procurement. Establishing a dedicated LDES mechanism, whether through auctions, contracts or capacity-based remuneration, can ensure that storage assets are available when needed to support reliability, flexibility and decarbonisation.

Demand

Expand demand-side participation through a broad portfolio of options, considering consumer protection mechanisms when necessary. Accelerating the rollout of dynamic and time-of-use retail pricing options can ensure that retail prices and network tariffs support demand-side response, storage and local energy exchange. Meanwhile, expanding smart metering and digital infrastructure would enable automation and real-time responsiveness.

Ireland should also encourage consumer participation by providing accessible data, user-friendly tools and information campaigns. Residential users should be allowed to engage in flexibility and ancillary service markets through aggregators, ensuring the interoperability of home energy systems, batteries and EVs. Furthermore, the government should update the National EV Charging Strategy with 2035 targets, facilitate EV participation in local flexibility markets and advance a regulatory framework for vehicle-to-grid services.

Unlock demand flexibility from large energy users. Without targeted incentives, large energy users may remain passive consumers and Ireland could miss a major opportunity to enhance flexibility and resilience. It should therefore consider linking existing Demand Side Unit payments to delivered flexibility using tiered performance incentives. It could also encourage data centre flexibility through connection requirements and market mechanisms such as incentives for workload shifting, onsite storage and operational optimisation.

Ireland already enables large energy users to participate in demand response through Demand Side Units, but participation remains voluntary and limited. Building on these arrangements and examples such as Texas, Ireland could establish a formal demand management programme for large loads (e.g. 75 MW or more), wherein participation in interruptible or flexible load schemes would be a precondition for grid access or continued operation. Unlike current practice in the country, which relies on emergency load shedding as a last resort, this approach could help proactively integrate large loads as grid resources, with clear contractual arrangements and compensation (when appropriate). Such a scheme would enable system operators to request demand reductions from LEUs during periods of system stress, not just in emergencies. Modelling suggests that data centres will be the largest single source of load flexibility to mitigate reliability risks in 2030.

Enable secure operations under high renewable penetration

While Ireland is already a pioneer in operating a relatively small system with few interconnections and high VRE levels, it must continue evolving its operational frameworks to support a renewables-led system. As it is expected to reach Phase 5 of VRE integration by 2030 and consolidate this position by 2035, with EirGrid targeting a limit of nearly 100% system non-synchronous penetration, the grid must be able to operate with almost entirely converter-connected sources such as wind and solar, batteries and interconnectors.

Unlike other VRE integration frontrunners such as Denmark, Ireland must keep its grid running securely with only limited interconnections, making operational security even more critical. This will require it to modernise system operations through updated practices, advanced modelling and greater automation, along with deeper digitalisation to improve real-time visibility, measurement and cybersecurity. While much of this work falls to grid operators, policymakers can support them by fostering collaboration, promoting global knowledge sharing and ensuring that system service markets evolve as grid needs change.

Continue to update operational standards and practices. The All-Island system is a leader in adapting operational standards and practices to accommodate high VRE levels securely, and the 2025-2035 Operational Policy Roadmap lays out a comprehensive approach to manage the transition to a highly electrified system with significant VRE penetration.

Necessary updates include transitioning from global to regional stability constraints; developing fault ride-through requirements for large energy users; formulating enhanced TSO-DSO co-ordination frameworks to improve visibility and control of distributed energy resources; and defining system services such as grid-forming capabilities and voltage support services. The April 2025 Iberian Peninsula blackout, caused by voltage instability rather than frequency issues, underscores the critical importance of ensuring that Ireland's renewable energy assets can provide voltage support services and that comprehensive voltage stability assessments are conducted in tandem with renewable energy deployment.

As grid code and operational practice updates are drafted by the system operator and approved by the energy regulator, policymakers should be establishing overarching energy policy and regulatory frameworks that reflect evolving technical requirements to facilitate stakeholder engagement in consultations; support demonstration and R&D initiatives that inform requirement updates; provide incentives to facilitate compliance with updated codes; and help align national grid codes with regional and international best practices.

Support the development of new advanced operational tools, studies and capabilities. Enabling secure renewables-led system operations will require a broad range of measures adapted to a system with abundant converter-connected resources and electrified end uses. Further simulation capabilities, such as for electromagnetic transients, and data collection and analytics platforms for assets such as smart meters and phasor measurement units, will be key to better understand and predict grid behaviour with a high number of converters, and to plan system operations accordingly. It will be critical for Irish policymakers to provide support and funding when appropriate, including by ensuring that corresponding power sector institutions have the skilled workforces they need.

Increase grid digitalisation while enhancing cybersecurity. Clear regulatory frameworks for grid-enhancing technologies allow grid operators to invest in digital solutions, flexibility and resilience, and improve measurement across the grid. On top of regulatory incentives, public-private funding can derisk and scale digital grid solutions, help upgrade existing SCADA, EMS, DMS and ADMS platforms, and support pilot projects to demonstrate the value of new technologies.

To future-proof these investments, standards for interoperability are needed to ensure that diverse systems and devices can communicate and integrate across the grid. It is also important to guarantee that privacy and cybersecurity frameworks are integrated from the design phase, in line with national and international standards.

Optimise the use of grid infrastructure through operational and contractual arrangements. These measures can provide short-term improvements by maximising the use of available grid capacity, and medium- to long-term gains by supporting the deferral of grid capacity investments. Ireland should also consider introducing operational arrangements such as Spain's Automatic Power Reduction System and Germany's Use-Instead-of-Curtail mechanism to improve operational efficiency by reducing renewable energy curtailment, or contractual arrangements such as the Netherlands' flexible connection agreements.

Advance workforce skills, strengthen partnerships and facilitate electrification

The success of Ireland's power system transition will also depend on how well it improves performance in the cross-cutting domains that underpin all the areas discussed in this report. It needs to enlarge its workforce and skills development; strengthen international collaboration; and accelerate the electrification of end uses. These enablers are essential not only to meet the country's energy and climate targets, but to support wider government goals such as affordability, housing delivery and economic growth.

Ensure skills and workforce development. An adequately skilled workforce will be required to safeguard the secure and efficient functioning of Ireland's increasingly complex power system, from planning and permitting to markets and operations. Training programmes will be key to ensure that power sector institutions – from the government to the energy regulator, system and market operators and enforcement organisations – have enough skilled staff to guarantee power system security and efficiency. Ireland also needs to consider offering reskilling support through dedicated programmes for workers in sectors for which fossil fuel use is expected to decline substantially as decarbonisation progresses (e.g. transport, heat, and fossil fuel-based power generation).

Collaborate regionally and globally to share knowledge, develop infrastructure and enhance joint procurement of key resources. While Ireland will most likely push some boundaries regarding VRE integration, it can still benefit greatly from collaborating with other countries and regions on solutions for a high-renewables electricity mix and learning from their experiences in areas in which Ireland itself is less advanced, such as electrification of end uses. Ireland can also consider developing new cross-border interconnectors for higher supply diversification. Finally, it can collaborate to advance joint procurement mechanisms for key resources such as low-emissions technologies, grid infrastructure and energy commodities, reducing procurement risks.

Implement policies to reduce economic barriers to electrification in industry and transport. In the industry sector, installing heat pumps and e-boilers involves high upfront capital investments to retrofit facilities, modify production lines, improve process integration and upgrade grid connections. Policy mechanisms to overcome such high capital expenditures and unlock private financing include targeted grants as well as tax credits and rebates. Successful EU member schemes include Germany's Federal Funding for Energy and Resource Efficiency in the Economy programme, which offers grants for industrial heat pump and electric boiler deployment, and the Netherlands' SDE++ subsidy, which supports industrial electrification projects alongside other low-carbon options.

In transport, a favourable policy environment that balances the upfront capital costs of EVs with running costs (e.g. vehicle and fuel levies) and introduces emissions-based measures can motivate consumers to choose electrification. Ireland can also ensure that all necessary infrastructure is in place to enable electrification, as Denmark has done through its co-financing measures for EV charging infrastructure and its range of incentives to encourage electric mobility.

Close the energy cost gap to speed up the shift towards electric technology options. To fully unlock the energy security benefits of electrification, Ireland should also consider reforming existing policies and market structures that undermine the competitiveness of electricity relative to fossil fuels. Restructuring energy pricing, taxation and levies to reduce retail electricity costs would make the electricity-to-fossil-fuel price ratio more favourable for electricity and encourage consumers to switch to heat pumps, e-boilers and electric vehicles. Sweden, for example, has reduced its electricity tax to an EU minimum of EUR 0.5/MWh, making electricity more affordable, and has successfully electrified its heating systems and made significant progress in electrifying transport as well.

Annex

Modelling methodology

To investigate future conditions in Ireland's power system, the IEA developed a power system model of Ireland using PLEXOS, optimised for least cost. The hourly production cost model simulates hourly unit commitment and security-constrained economic dispatch to meet demand while respecting planned system constraints. Assumptions for 2030 are based on EirGrid's recent All-Island Resource Adequacy Assessment (AIRAA), while 2035 assumptions are based on the Self-Sustaining scenario of EirGrid's Tomorrow's Energy Scenarios 2023 (TES).

Regional representation and transmission

Ireland, Northern Ireland, France and Great Britain are modelled explicitly as regions, with interconnection between them but no intraregional transmission constraints, as subregional capacity and demand splits were not available in sufficient detail. To analyse and comment on results for Ireland only, it was necessary to model Ireland and Northern Ireland as separate regions in the same zone, despite these two jurisdictions forming one bidding zone in the Single Electricity Market (SEM). Ireland and Northern Ireland were grouped into one zone to replicate the SEM.

The directly interconnected countries of France and Great Britain are explicitly included in the model, with transmission capacity between each region based on existing lines and those under construction or announced. The effects of third countries connected to Great Britain and France are included implicitly by accounting for the flows from the ENTSO-E Ten-Year Network Development Plan 2024 (TYNDP) outputs.

Input assumptions for transmission capacity between modelled regions

Transmission corridor	2030 transfer capacity (MW)	2035 transfer capacity (MW)
IE - GB	1 000	1 750
IE - FR	700	1 400
IE - NI	1 200	1 200
FR - GB	5 600	5 600
NI - GB	500	1 300

Notes: IE = Ireland. NI = Northern Ireland. GB = Great Britain. FR = France.

Additional interconnection with Great Britain is assumed after 2030, with 750 MW of additional capacity by 2035. A second line to France is assumed after 2030, duplicating the 700-MW capacity of the Celtic Interconnector. When modelling assumptions were finalised, the North-South Tie Line was assumed to be operational in 2030, though uncertainty on its completion date persists.

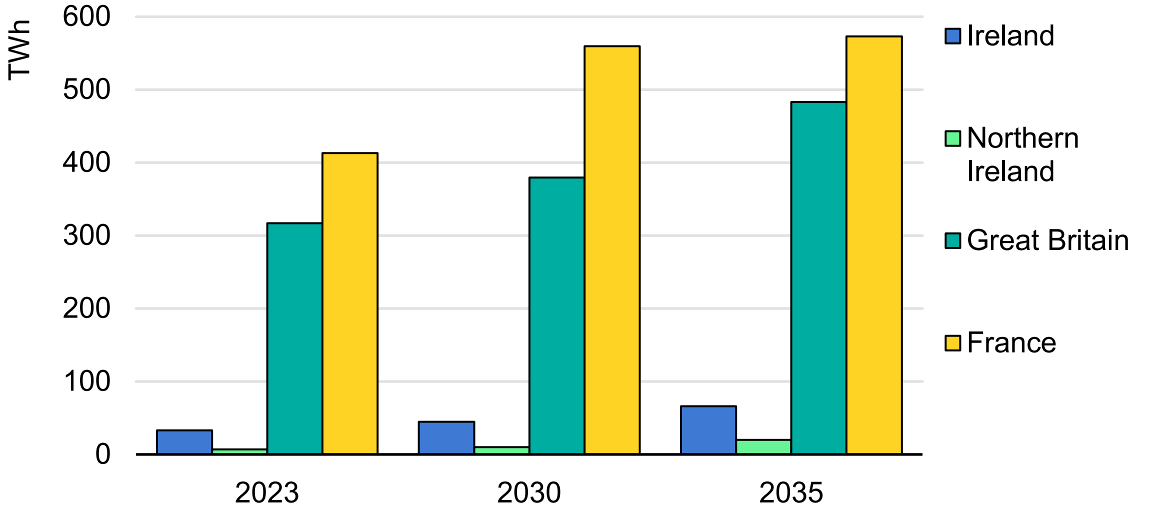
France and Great Britain are interconnected using the TYNDP capacity for 2030, meaning ~1 600 MW more capacity than in 2025. Given the uncertainty of the project pipeline beyond that increase, no further additions are assumed to 2035.

Demand

Hourly electricity demand for Ireland and Northern Ireland is taken from EirGrid data; 2030 assumptions are from AIRAA, and 2035 assumptions are from the Self-Sustaining scenario of TES 2023. AIRAA assumptions account for strong data centre growth to 2030 but reflect more conservative electrification expectations for other sectors. Transport and residential electrification rates are higher in 2035, presenting a power system that is progressing towards Ireland's cross-sectoral electrification targets.

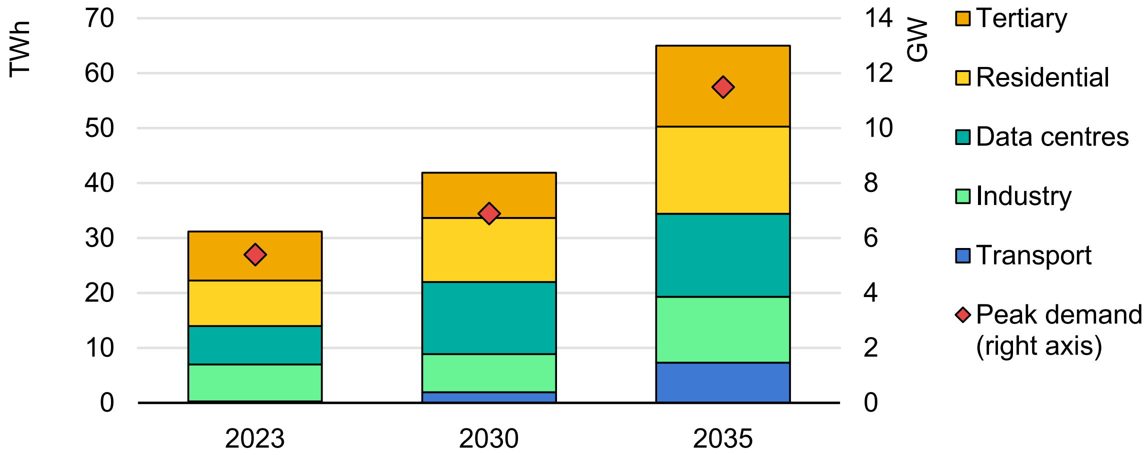
Demand for Great Britain and France is taken from TYNDP 2024 assumptions for the National Trends scenario in 2030 and the Global Ambition scenario in 2035, reflecting the higher ambition of the 2035 assumptions for Ireland.

Total annual electricity demand by region, 2023 (historical), 2030 and 2035 (scenarios)



Sources: for France, Ministry of Ecological Transition and Territorial Cohesion (2024), *Chiffres clés de l'énergie Édition 2024* (2023 data for France); for the United Kingdom, Department for Energy Security and Net Zero (2024), Digest of UK Energy Statistics (2023 data for Great Britain); IEA analysis based on the ENTSO-E Ten-Year Network Development Plan 2024 National Trends (2030) and Global Ambition (2035) scenarios (2030 and 2035 data for France and Great Britain); EirGrid (2025), All-Island Resource Adequacy Assessment (2030 data for Ireland and Northern Ireland); EirGrid (2023), Tomorrow's Energy Scenarios (2035 data for Ireland and Northern Ireland).

Annual electricity demand in Ireland by sector (left axis) and peak demand (right axis), 2023 (historical), 2030 and 2035 (Adapted Transition Pathway)



Note: "Tertiary" includes commercial and service demand. 2030 and 2035 values are from the Adapted Transition Pathway.

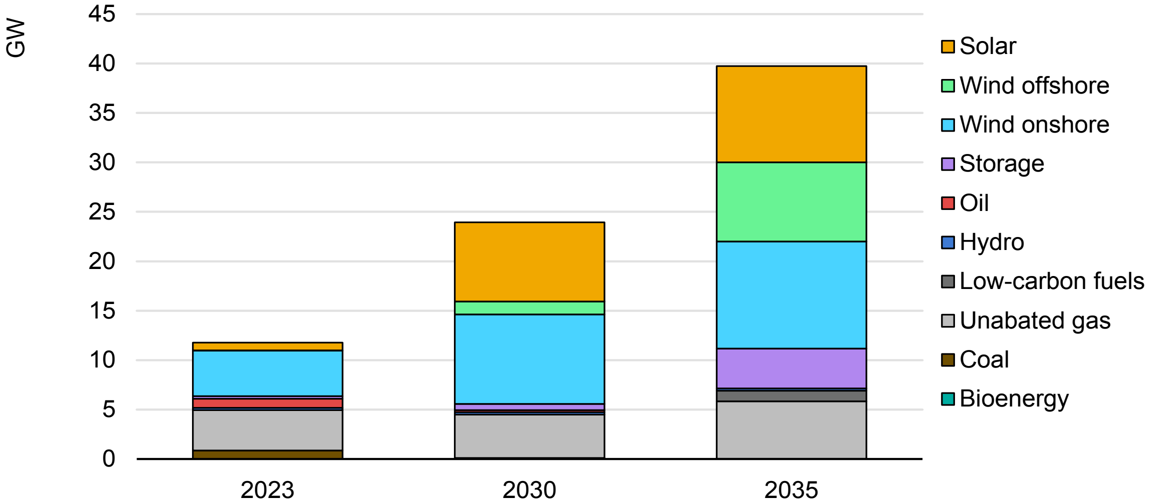
Generation

Installed generation capacity, technical characteristics (i.e. heat rates, ramp rates, minimum up/down time, minimum stable level, outage rates and mean time to repair) and cost parameters (i.e. fuel costs and variable operation & maintenance costs) are based on EirGrid and public-domain data. When plant-specific information was unavailable, generic characteristics were assumed according to plant technology.

For Ireland and Northern Ireland, larger existing thermal plants were captured at plant level for 2030 but aggregated for 2035 to avoid introducing bias from speculative choices on plant closures. Smaller plants and variable renewables, as well as all plants in Great Britain and France, were aggregated by technology and region. Aggregated plants were modelled with representative unit sizes for each region to maintain realistic unit commitment decisions, using generic technical parameters according to plant technology.

Capacity assumptions for 2030 are based on EirGrid's recent All-Island Resource Adequacy Assessment (AIRAA), while 2035 assumptions are based on the Self-Sustaining scenario of EirGrid's Tomorrow's Energy Scenarios 2023 (TES). Although the EirGrid TES scenarios incorporate hydrogen turbines and gas carbon capture and storage capacity, this technology remains unproven at scale. Moreover, there is a lack of clear intention from market participants in Ireland to deploy this technology in the coming decade as well as uncertainty around the availability of low-carbon hydrogen. This capacity was therefore included in low-carbon fuels, recognising that other technology may be needed even though the 5.7-TWh biomethane production target would be sufficient to provide all this low-carbon dispatchable generation in the 2035 model results.

Annual installed generation capacity by fuel type in Ireland, 2023 (historical), 2030 and 2035 (Adapted Transition Pathway)



Operational constraints

To produce an effective security-focused analysis, several operational limits were enforced in the model alongside technical generator parameters, to replicate real-world operating conditions. These were based on EirGrid's and SONI's [Operational Policy Roadmap 2025-2035](#) and confirmed with EirGrid.

Minimum conventional units online

The 2024 minimum of four conventional units in Ireland and three in Northern Ireland was relaxed to two in Ireland and one in Northern Ireland for 2030. The constraint was removed for 2035, meaning no minimum number of conventional units was enforced.

Inertia

The system operators plan to maintain the current All-Island minimum inertia level of 23 gigawatt-seconds (GWs). Trials are planned to introduce regional inertia constraints for Ireland and Northern Ireland, but the overall minimum is expected to be maintained. This constraint was implemented in the modelling to enforce 23 GWs of inertia in each hour. The recent procurement target of 10 GWs of low-carbon inertia services are assumed to be operational across Ireland and Northern Ireland in 2030, and a second, duplicate round of procurement is assumed to deliver an additional 10 GWs of inertia for 2035.

As discussed in the report, although it would be theoretically possible to cover the entire minimum inertia with low-carbon services, this has yet to be tested on a systemwide scale. A detailed technical evaluation and real-world trials would be required to verify they could cover 100% of the system services of thermal generation.

Maximum system non-synchronous penetration

This restriction limits the proportion of supply in each hour from non-synchronous sources such as solar and wind, as well as from interconnection and batteries. The current limit of 75% non-synchronous supply in the system is relaxed to 95% in 2030 and is removed completely in 2035.

Reserves

Electricity system operators hold spare generation capacity at all times to adapt to the various uncertainties inherent in system planning, such as demand or generation forecast errors or unplanned network or generator outages. In addition to meeting hourly demand, the model was required to hold reserves to reflect this practice. Reserves were enforced for each region, with Ireland's and Northern Ireland's covering the expected AIRAA reserve levels and Great Britain's and France's covering their largest possible generator loss, a standard measure of system reserve.

Sensitivities

Numerous sensitivities were examined to explore key risks to the Adapted Transition Pathway scenario. While the main body of this report discusses these analyses, the following table presents the input assumptions.

Sensitivity assumptions applied to the 2030 and 2035 horizons of the Adapted Transition Pathway scenario

Description	2030 differences vs base	2035 differences vs base	Comment
High residential demand	+2.5 TWh of residential demand	No 2035 sensitivity	Using a forecast that meets the housing construction target, addressing the uncertainty around house-building and demographic growth.
Low-VRE period	Base VRE generation profiles with a two-week period of available capacity factors overwritten using the two-week period of lowest rolling combined solar and wind generation potential available in ERA5	Same settings as 2030	Copernicus ERA5 data was used to identify periods with the lowest two-week rolling combined solar and wind generation potential in Ireland in the last 20 years. This addresses periods of low VRE availability in high-VRE systems.

Description	2030 differences vs base	2035 differences vs base	Comment
Long-duration energy storage	No 2030 sensitivity	Sensitivities with 50% and 0% base LDES capacity (1 840 MW of 8h duration or longer in Ireland)	As discussions on a long-duration storage regime are ongoing, no LDES is assumed operational in 2030.
Interconnector outages	Reduction of transfer capacity: IE to GB: -500 MW IE to FR: -700 MW	Same settings as 2030	Equivalent of a yearlong outage of one line between IE and FR, and IE and GB.
Data centre flexibility	Two separate sensitivities with data centre shifting: 1. For 1 hour, up to 20 times per year 2. For up to 4 hours, up to 5 times per year	Same settings as 2030	Data centres have displayed high price elasticity of demand, so short-duration peak shaving is considered more likely than longer-duration shifting.

Notes: VRE = variable renewable energy. LDES = long-duration energy storage. IE = Ireland. GB = Great Britain. FR = France.

Abbreviations and acronyms

AC	alternating current
ACC	accelerated case
ACER	Agency for the Cooperation of Energy Regulators
ADMS	advanced distribution management system
AIF	Agile Investment Framework
AIRAA	All-Island Resource Adequacy Assessment
BESS	battery energy storage system
BEV	battery electric vehicle
CAPEX	capital expenditure
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage
CEST	Central European Summer Time
CHP	combined heat and power
CI	customer interruptions
CML	customer minutes lost
COP	coefficient of performance
CPPAs	corporate power purchase agreements
CRM	Capacity Remuneration Mechanism
CRU	Commission for the Regulation of Utilities
DCEE	Department of Climate, Energy and the Environment
DER	distributed energy resources
DHLGH	Department of Housing, Local Government and Heritage
DLR	dynamic line rating
DMAP	Designated Maritime Area Plan
DMS	distribution management system
DS3	Delivering a Secure Sustainable Electricity System
ECB	European Central Bank
EMS	energy management system
ENTSO-E	European Network of Transmission System Operators for Electricity
EPA	Environmental Protection Agency
EPMG	Energy Policy and Modelling Group
ERA5	European Centre for Medium-Range Weather Forecasts Reanalysis v5
ESB	Electricity Supply Board
ESBN	Electricity Supply Board Networks
ETS	emissions trading system
EU	European Union
EV	electric vehicle
EVSE	electric vehicle supply equipment
FACTS	flexible AC transmission system
FASS	future arrangement for system services
FFR	fast frequency response
FR	France
GB	Great Britain
GFM	grid-forming

GHG	greenhouse gas
HDD	heating degree day
HSE	Health Service Executive
HVDC	high-voltage direct current
ICE	internal combustion engine
IE	Ireland
IEC	Integrated Energy Companies
JRC-IDEES	Joint Research Centre's Integrated Database of the European Energy System
LCIS	low-carbon inertia services
LCOH	levelised cost of heat
LDV	light-duty vehicle
LED	low energy demand
LEU	large energy user
LNG	liquefied natural gas
LOLE	loss of load expectation
MARA	Maritime Area Regulatory Authority
MITECO	Ministry for the Ecological Transition and the Demographic Challenge
NEP	national energy projection
NI	Northern Ireland
NIS	network and information systems
O&M	operations and maintenance
ONEE	Office National de l'Électricité et de l'Eau Potable
ORE	offshore renewable energy
PMU	phasor measurement unit
POD	power oscillation damping
PPA	power purchase agreement
PR	price review
PSO	public service obligation
PSS	power system stabiliser
PV	photovoltaic
R&D	research and development
RAA	renewables acceleration areas
REC	renewable energy community
RED	Renewable Energy Directive
REE	Red Eléctrica de España
REN	Rede Eléctrica Nacional
RES-E	renewable energy sources - electricity
ROCOF	rate of change of frequency
RTE	Réseau de Transport d'Électricité
SAP	sectoral adaptation plan
SCADA	supervisory control and data acquisition
SEAI	Sustainable Energy Authority of Ireland
SEC	sectoral emission ceilings
SEM	Single Electricity Market
SEMO	Single Electricity Market Operator

SHIP	solar heat in industrial processes
SNSP	system non-synchronous penetration
SONI	System Operator for Northern Ireland
STATCOMS	static synchronous compensators
TCO	total cost of ownership
TEG	temporary emergency generation
TES	Tomorrow's Energy Scenarios
TSO	transmission system operator
UR	Utility Regulator
VAT	value-added tax
VRE	variable renewable energy
VRT	vehicle registration tax
VTT	voltage trajectory tool
WAM	With Additional Measures
WEM	With Existing Measures

Glossary

GJ	gigajoule
GW	gigawatt
GWh	gigawatt hour
GWs	gigawatt-second
Hz	Hertz
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
Mt	million tonnes
Mt CO_2	million tonnes carbon dioxide
Mt CO_2/yr	million tonnes carbon dioxide per year
Mtoe	million tonnes of oil equivalent
MW	megawatt
MW_{th}	megawatt thermal
PJ	petajoule
PJ/yr	petajoule per year
TWh	terawatt
TWh_{th}	terawatt hour thermal

See the IEA glossary for a further explanation of many of the terms used in this report.

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