Background material: Forecasts of plausible rates of generation technology deployment 2024–2040

Briefing note for study participants

Note: The information in this briefing note was initially published in two separate briefing notes in February and April 2024, as supplementary reference material for participants in SEAI's expert elicitation study. The first brief focused on variable renewables and the second on deployment of hydrogen, ammonia and carbon capture and storage in the power sector. Aimed at interviewees, the content provided an overview of the factors influencing power generation technology deployment in Ireland as of Q1 2024. Here they are combined in a single report for ease of reference. The results of the expert elicitation forecasts can be accessed at https://www.seai.ie/renewable-energy/decarbonised-electricity-system-study.

Contents

1. Introduction

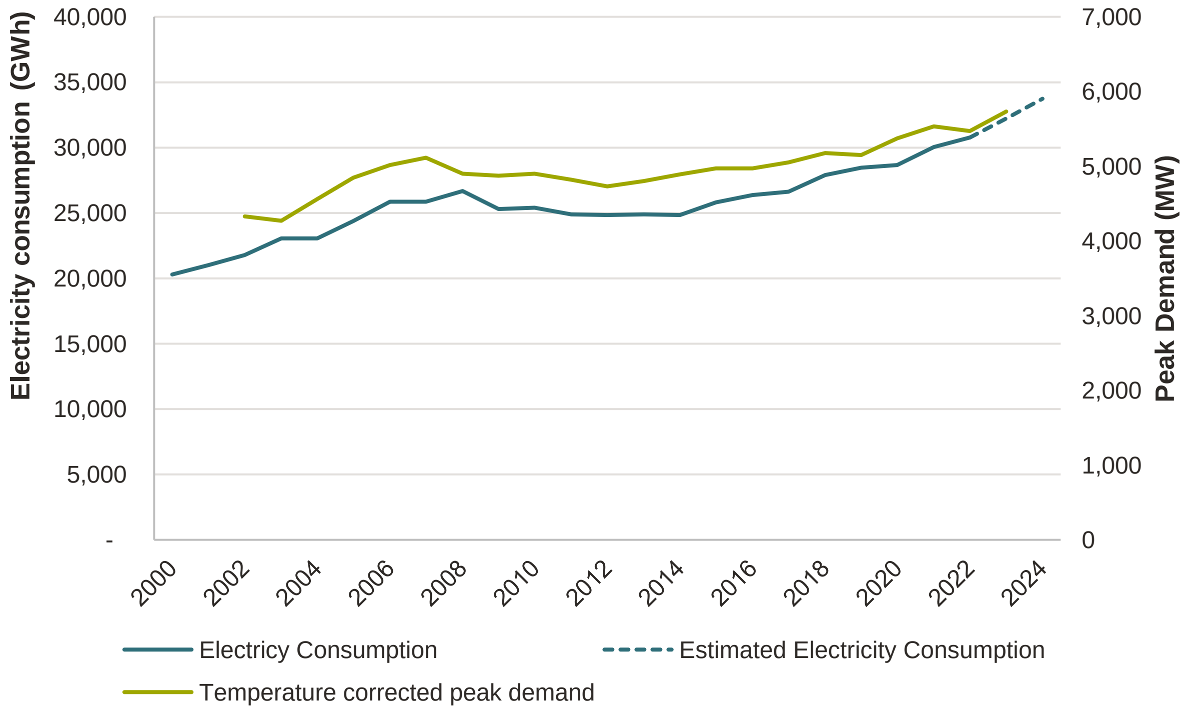
This document should be read in preparation for the Sustainable Energy Authority Of Ireland (SEAI) expert elicitation on plausible deployment scenarios and rates of offshore wind (OFW), onshore wind (ONW), solar PV (SPV), hydrogen (H2) and ammonia (NH3) fuels and generation with carbon capture and storage (CCS). It provides accompanying information on factors that may influence the deployment of these technologies in the coming years within the Republic of Ireland (ROI). It may serve as a starting point and aid in making explicit the factors and assumptions that shape your own deployment scenarios and forecasts during the interview.

Sections 2-4 of the brief highlights factors that affect the deployment of all the listed technologies in the ROI. Sections 5-10 highlight factors that affect variable renewable generation deployment in particular. Sections 11–15 add additional points that are specific to each of the technologies separately. Overall, the brief does not assume or recommend any deployment scenarios or rates but seeks to highlight the factors or drivers that may affect deployment rates of variable renewable generation technologies in the ROI. We expect that experts will bring additional data, assumptions and causal models (formal or mental) to the discussion to construct their forecasts as part of the elicitation.

2. Historical electricity demand and supply in Ireland

This section summarises the historical electricity demand in Ireland and the sources of fuel used to satisfy this demand. *Figure 1* shows the electricity demand and peak demand in Ireland from 2000 to the end of 2023.

Figure 1: Electricity consumption



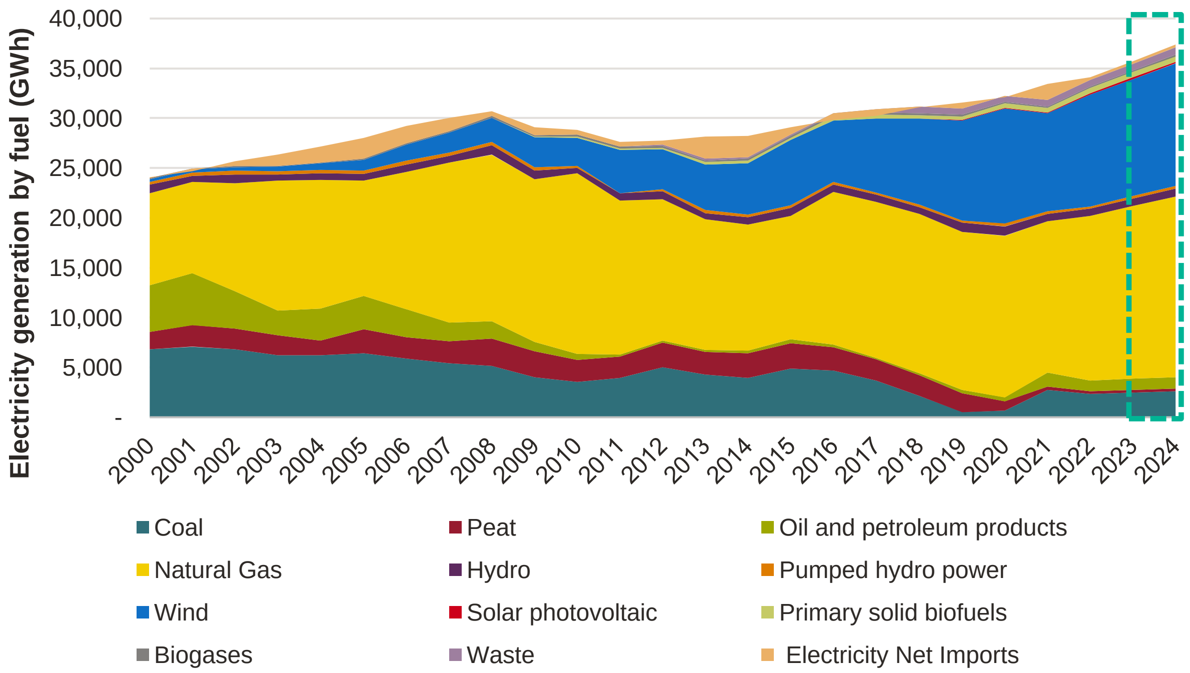
Source: SEAI, Key Energy Statistics (Available [here]) and EirGrid (January 2024), Grid Capacity Statement 2023-2032 (Available [here]).

Note: The chart assumes that the demand for 2023 and 2024 grew and will grow in line with the growth rate in GCS 2023.The Peak Demand showed is the historic, temperature-corrected peak.

Figure 2 illustrates the fuels used to meet electricity demand from 2000 to 2023. Natural gas is the most common fuel type used for electricity generation in Ireland. Electricity generated with natural gas reached its peak in 2010 (18.11 TWh, equivalent to 62.8% of the electricity generated). Since then, it has stayed between 15.5 to 16.5 TWh, and the percentage it represented of total production has decreased. In 2023, natural gas accounted for 43% (14.2 TWh) of the electricity generation.[1]

Electricity generated by onshore wind power has increased substantially over the period considered. Since 2010 there has been a steady increase in electricity generation from onshore wind power, from 2.8 TWh in 2010 to 11.6 TWh in 2023. Proportionally, wind has increased from generating 10% of electricity to 35% of electricity in 2023, at an average annual growth rate of approximately 12%. As shown in *Figure 3*, installed wind capacity has increased substantially over the past decades, from 117 MW in 2000, to 4.7 GW in September 2023.[2] 2017 holds the record for most installed capacity in a year at 507 MW. However, the pace of adding wind capacity has slowed in recent years, from 450 MW in 2019 to a low of 9 MW in 2021. In 2023, 185 MW of onshore wind was installed.[3]

Figure 2: Electricity generation by fuel



Source: Eurostat, Dataset nrg_bal_peh (Available here), CSO, Fuel used in electricity production (Available here).

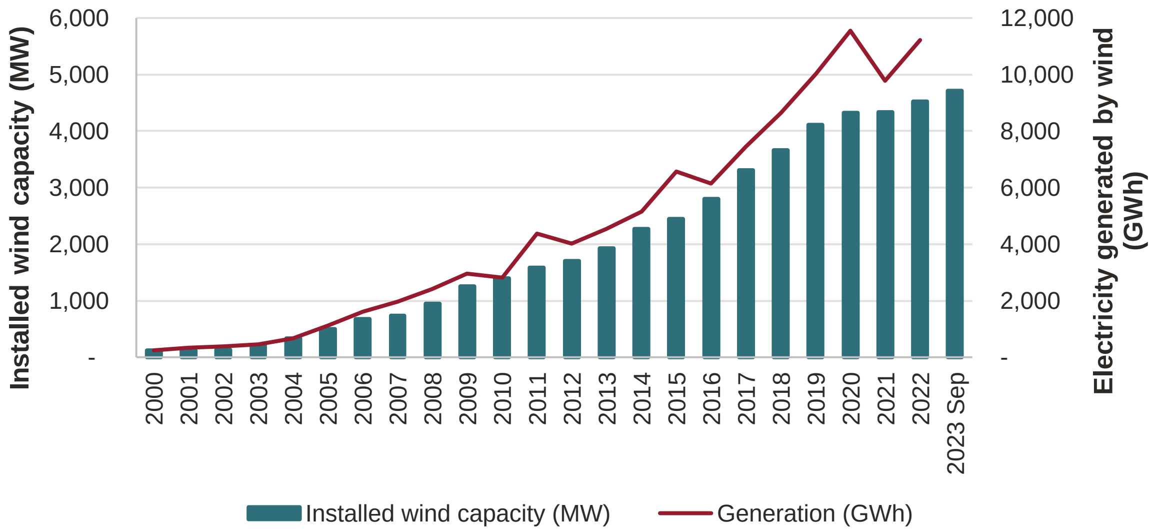
Note: Data for 2023 and 2024 are calculated based on the assumption that electricity generation has and will continue to grow in accordance with the GCS 2023 growth rate and that the percentage breakdown of fuels remains consistent with that observed in 2022.We note that the total in this chart is slightly above the electricity consumption in the figure above. This is likely due to transmission and distribution losses, as well as own electricity use.

[1] EirGrid (January 2024), System and Renewable Data Summary. Available here

[2] Arklow Bank Phase 1 (25 MW), constructed in 2005 as a demonstration project, is Ireland's first and only offshore wind farm. Its generation is not reported separately.

[3] This figure excludes DSO data for Q4 2023.

Figure 3: Installed wind capacity and electricity generated by wind



Source: *Eurostat, EirGrid*

Solar contribution to electricity supply can be divided between small scale solar, mostly on rooftops, and utility-scale solar farms. The small-scale sector has increased strongly with recent Government incentives, from around 0.01–0.1 % of supply. Utility scale solar projects have recently added significantly to national supply. In 2023, solar PV generated 372 GWh (1%) of electricity. *Table 1* below synthesises the data available on solar installed capacity in Ireland. By the end of 2023, ROI has approximately 744 MW of installed solar capacity, with at least half of it (384 MW) connected in 2023.

Table 1: Installed solar capacity

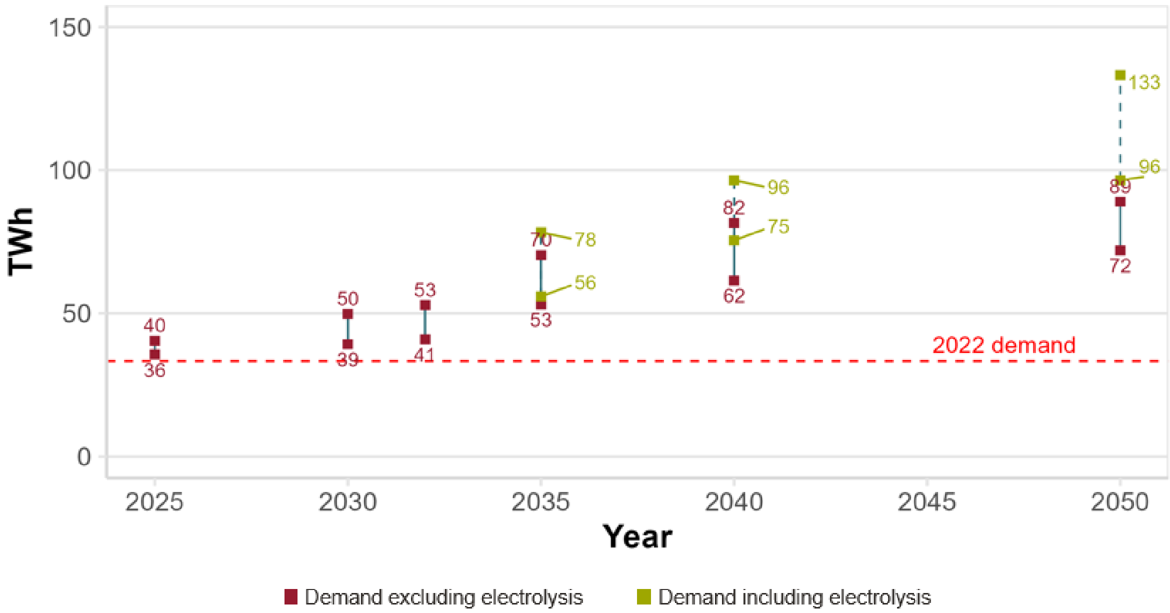
Type of solar	MW	Comment
Transmission-connected	369.0	• All plant connected in 2023 • 4 projects, between 60 to 110 MW
Distribution connected	67.1	• 51.7 MW connected in 2022, 15.4 in 2023 • 17 projects, of which 4 (40 MW) above the 5 MW size. 5 projects (25.5 MW) are between 1 and 5 MW.
Mini-generation	5.0	• Mini-generation projects typically have a capacity between 17kVA and 50kVA. Usually installed by businesses and farms for consumption of their self-generated electricity
Micro-generation	208.0	• Solar PV installed on household roofs
Auto-production	95.0	• No export to the grid
Total capacity	**744.1**	

Source: *EirGrid (January 2024), System and Renewable Data Summary Report, Available here; ISEI (June 2023), Scale of Solar, Available here.*

3. Projections of Irish electricity demand up to 2050

Figure 4 and *Figure 5* summarise the different projections of electricity demand and peak demand by showing the range of the forecasts.

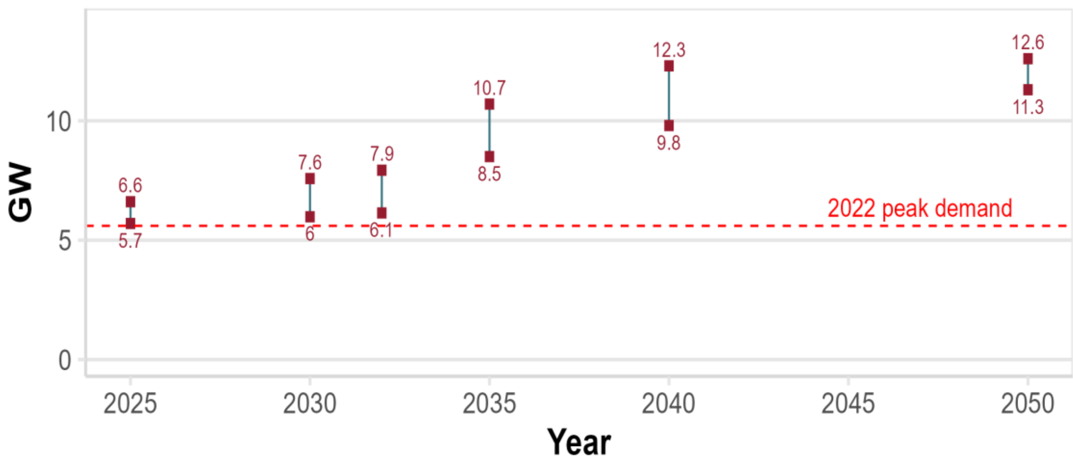
Figure 4: Electricity demand forecast range



Source: EirGrid GCS 2023, EirGrid TES 2023, SEAI Heat Study, and SEAI National Projections.

Note: This chart displays the ranges in electricity demand forecasts for GCS 2023, TES 2023, SEAI Heat Study, and SEAI National Projections. The points in red represent the minimum and maximum aggregate electricity demand. The points in green and the dotted line show the range including the demand for electrolysis as per TES 2023.[4] Note that EirGrid states that this demand may be satisfied by off-grid plants.

Figure 5: Electricity peak demand forecast range



Source: EirGrid GCS 2023, EirGrid TES 2023

Note: This chart displays the ranges in peak electricity demand forecasts for the sources considered (GCS 2023, TES 2023). Note that TES 23 does not report peak demand considering the additional load for green hydrogen production.

[4] EirGrid considers electrolysis demand separately, as this load could be supplied by non-grid-connected generators and therefore should not be considered as part of the electricity load.

Peak demand is expected to increase at a slightly lower rate than total demand due to the expected increase in demand flexibility. The CAP has established targets for demand flexibility, aiming for 15–20% by 2025 and 20–30% by 2030. The TES 2023 scenarios foresee a need for 20–50% demand flexibility by 2050.

Several public consultations have been launched to date relating to demand-side flexibility, including the CRU's consultation on National Energy demand,[5] ESB Networks' consultation on Demand Flexibility Product Proposal,[6] and EirGrid's consultation on Long Duration Energy Storage.[7] [8] In its document, the CRU recognises the urgency for Ireland to progress on demand flexibility and focuses on near-term actions. According to the CRU, the greatest potential in the near term lies in procuring flexibility services (explicit flexibility) from LEUs and storage.[9] ESB Networks' and EirGrid's consultations align with this view. ESB Networks proposes to procure demand flexibility products in locations where there is a high system need. It anticipates of procuring 100 MW in the first round, and up to 500 MW by 2025. Similarly, EirGrid aims to launch its procurement scheme for long energy duration storage in January 2025.

[5] CRU (December 2023), National Energy Demand Strategy. Available here.

[6] ESBN (December 2023), Demand Flexibility Product Proposal. Available here

[7] We note that the SOs have already implemented various programmes. With DS3, EirGrid procures services that provide flexibility. ESBN has recently launched programmes as "Beat the Peak Business" and "Is this a good time?"

[8] EirGrid (October 2023), A call for evidence on the market procurement options for Long Duration Energy Storage (LDES). Available here

[9] Generally speaking, demand flexibility could be provided by different technologies/customers (domestic customers, business and storage providers) and incentivised in different ways (differentiated tariffs, dedicated procurement contracts, and clauses in connection contracts).

4. Grid capacity

Decarbonising the Irish power sector requires a significant programme of works to expand and reinforce the transmission and distribution grid. EirGrid describes the grid investment required to meet current renewable electricity targets[10] as "simply the most ambitious programme of works ever undertaken on the transmission system in Ireland".[11] It requires significant and timely capital expenditure and human resources from the TSO and DSO, as well as depending on the alignment of several other factors. These include timely planning decisions (including granting of licences for site investigation); the availability of sufficient outages and the efficient utilisation of outage windows by multiple parties to deliver required grid infrastructure; availability of the road network for routing of underground cable infrastructure; and the availability of suitable land for strategic network investments.[12]

Significant investment in Ireland's electricity grid is required to accommodate additional generation, especially renewables, and to meet expected demand growth. EirGrid estimates that investment of €3.4 billion is required in transmission capex by 2030.[13] This includes both connecting generation and reinforcing the network to accommodate additional load. In comparison, the transmission system and asset owners spent, on average, €152 million per annum on total regulatory capex in the five years to 2022. In other words, annual capex will need to nearly triple for the rest of the decade to enable the 2030 RES-E target.

System operators have previously undertaken programmes of work to support the rapid deployment of renewables, although not all planned capex has always been delivered. For example, the previous price control period for the transmission system operator (TSO) and asset owner (TAO) ran from 2016-2020. The regulator had allowed for €1,024 million of capex, but €823 million was spent during the period.[14] The key issues affecting project delivery during this period were identified as land access and planning issues, in particular social opposition to large scale 400kV projects.[15] Planning issues are discussed in more detail below.

EirGrid has identified several risks to delivery of the necessary grid investment.[16] These include a shortage of materials (for example, HV cable); security of supply constraints or other system conditions restricting outage windows; a shortage of human resources (including contractors and sub-contractors) to support a growing pipeline of projects to 2030; and delays on land acquisition and land access.[17]

One proposal that is currently being piloted to facilitate increased volumes of renewables connecting to the network is Renewable Hubs. Renewable Hubs would be advanced substations where network capacity will be created in advance of an expected pipeline of projects (for example, onshore wind in the pilot scheme). If successful, this could reduce the time taken for relevant clusters of renewable projects to connect to the grid.

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[10] The Climate Action Plan 2023 (and the draft for 2024) targets for 2023 are 9 GW of solar, 8 GW of onshore wind, and 5 GW of offshore wind.

[11] EirGrid (2023), Network Delivery Portfolio (NDP) Guidance Document. Available here

[12] EirGrid (2023), Shaping Our Electricity Future Roadmap: Version 1.1. Available here

[13] EirGrid (2023), Shaping Our Electricity Future Roadmap: Version 1.1. Available here

[14] CRU (2021), TSO and TAO Transmission Revenue for 2021 2025: Decision Available here

[15] CRU (2021), TSO and TAO Transmission Revenue for 2021 2025: Decision Available here

[16] EirGrid (2023), Shaping Our Electricity Future Roadmap: Version 1.1. Available here

[17] EirGrid (2023), Investment Plan Delivery Report 2022. Available here

5. Grid connection

This section discusses the onshore wind and solar grid connection policies and grid development plans. Offshore connection policy is discussed separately in Section 10.

The connection pathway for onshore wind and solar projects is via the CRU's Enduring Connection Policy (ECP) approach. Projects with planning permission are able to apply for grid connection in batches during specific time windows. *Table 2* shows the total connection capacity for wind and solar offered on ECP agreements that are not operational or have a RESS offer.

Table 2: Current ECP agreements (not operational or in RESS) for solar as of October 2022. ECP2.4 figures include hybrid projects with storage

	ECP 1 (MW)	ECP 2.1 (MW)	ECP 2.2 (MW)	ECP 2.3 (MW) (A)	ECP 2.4 (MW) (A)	Total ECP (MW)
Solar	60	544	1,079	1,835	1,653	**5,171**
Wind	83	432	340	422	406	**1,682**

The CRU is currently consulting on a new grid connection policy. The recast Renewable Energy Directive requires that the permit granting process (including planning permission and grid permitting) for onshore renewable projects shall not exceed two years for projects. The current permit-granting processes in Ireland do not adhere to these timelines.[18] The timelines for grid connection permitting alone (excluding planning) can be more than two years.[19] This new policy consultation has been driven primarily from delays in onshore wind applications, but the new policy would also likely be relevant for solar.

[18] CRU (December 2023), Electricity Generation and System Services Connection Policy. Consultation Paper. Available here

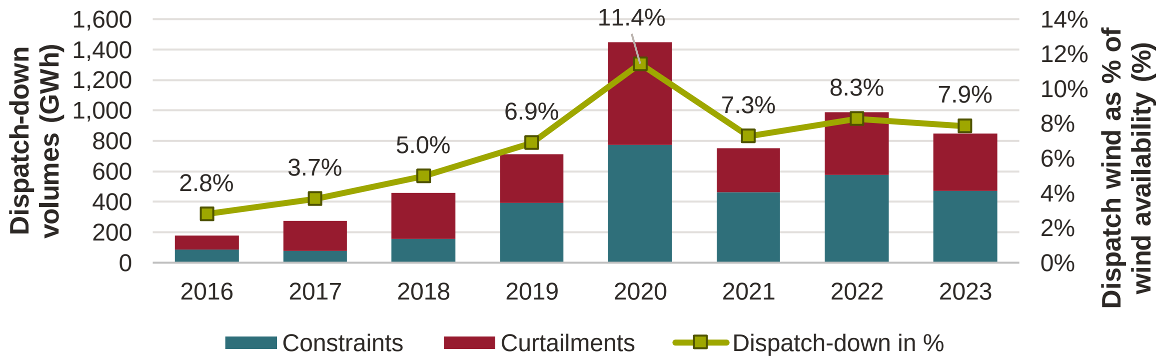
[19] CRU (December 2023), Electricity Generation and System Services Connection Policy. Consultation Paper. Available here

6. Grid management

As the penetration of variable renewables increases, existing and new system services will be required to ensure system stability. Without these system services, an increasing proportion of renewable electricity will be dispatched down.[20] Over the past decade, EirGrid has successfully increased the System Non-Synchronous Penetration (SNSP) on the Irish grid from 50% to 75%, addressing one of the sources of dispatch-down.[21]

Figure 6 shows the amount of wind dispatch-down in Ireland for the period 2016-2023. About 56% of the wind dispatched down was caused by local network constraints, while the remainder was due to system-wide factors. In 2023, 37 GWh of solar PV, equivalent to 9.3% of the available volume, was dispatched down.[22]

Figure 6: Historical level of wind constraint and curtailment



Source: EirGrid (2023), DD Summary Spreadsheet. Available here

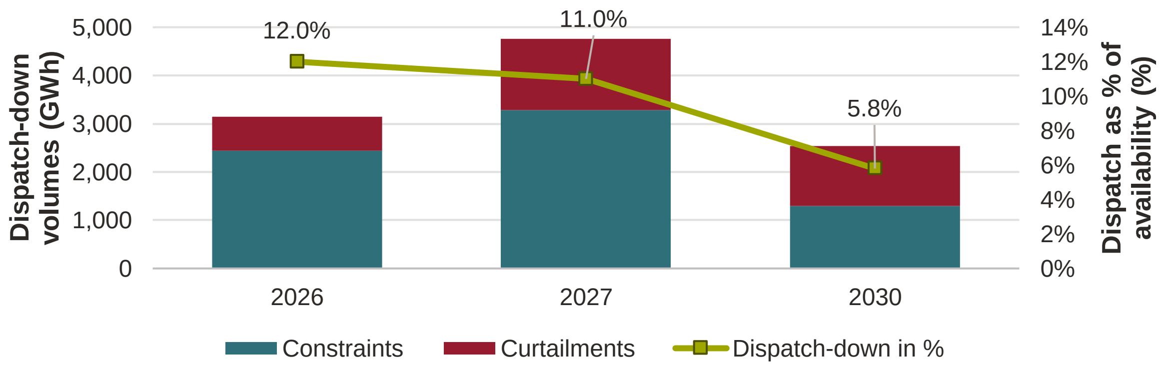
To reach an 80% RES-E target, the Irish system needs to operate at a SNSP close to 100%. This will require various forms of flexibility, including new regulatory and market practices and technologies to minimise dispatch down of renewables.[23] The CAP 2023 set a target of keeping dispatch-down below 7% by 2030.[24] However, a recent independent estimate finds that dispatch-down of renewables could reach at least 16% by 2030 (in a scenario where the ROI reaches its 2030 RES-E targets), even if various forms of flexibility measures were successfully introduced, including synchronous condensers, medium term storage, and demand response.[25]

[20] Dispatch-down of renewable energy refers to the amount of renewable energy that is available but cannot be used by the system. There are typically three reasons why renewable generation is dispatched down: curtailment (operational limits of the system), constraint (local network limitations), oversupply (total available generation exceed system demand plus interconnection export flows).
[21] EirGrid (2023), Shaping Our Electricity Future Roadmap: Version 1.1. Available here
[22] EirGrid reports dispatch-down volumes and percentages specifically for solar from 2023.
[23] As, for example, the reduction of the minimum number of conventional units, synchronous condensers, grid-forming and other emergent technologies. Source: EirGrid (2022), Operational Policy Roadmap 2023-2030. Available here
[24] Government of Ireland (December 2022), Climate Action Plan 2023. Available here
[25] Stanley et al (2023), Strategies to increase grid flexibility for an isolated system with over 80% of renewable electricity in 2030. Available here

Figure 7 shows forecasts for constraints and curtailment levels related to wind and solar in Ireland for 2026, 2027, and 2030. While EirGrid presents different scenarios, the Figure shows the numbers for the EPC scenario.[26] According to EirGrid, there is an expected increase in both volume and percentage of dispatch-down until 2027. This is due to growing electricity demand and RES installed capacity, leading to more curtailment and constraints. After 2027, EirGrid estimates a reduction in the level of dispatch-down to 5.8%, thanks to network reinforcement and interconnectors.

Dispatch-down due to oversupply is uncommon in Ireland today.[27] [28] However, according to EirGrid it may become the biggest reason for dispatch-down in the medium-term.[29]

Figure 7: Forecast level of constraints and curtailment (highest scenario)



Source: *EirGrid (Q4 2022), Enduring Connection Policy 2.2, Available here*
Note: *This chart displays EirGrid's maximum level forecasts for curtailment and constraints (scenarios: 2025 EPC, 2030 EPC, and 2030 EPC + 5GW Offshore)*

RES generators may receive compensation for some or all of the electricity subject to dispatch-down, mitigating the financial risks associated with dispatch-down. For example, successful projects in the RESS 3 and ORESS auctions will be compensated at the strike price for availability not converted to generation, whether due to oversupply or curtailment.[30] However, there is a risk that such schemes will distort the market signal for developers to co-invest in storage.[31] RES generators also have the potential to recover some of the lost revenue associated with dispatch-down by redirecting that electricity towards hydrogen production. As the temporal characteristics of dispatch-down may not match the minimum load factor requirement of electrolysers, the economic viability of the latter remains uncertain.

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[26] The EPC scenario assumes 11.1 GW of RES in 2027, and an additional 5 GW of offshore in 2030

[27] Oversupply is primarily influenced by demand and installed generation (although interconnection also impacts oversupply)

[28] RES generation surpassed the demand for the first time in July 2023, and in that case some of the electricity was exported to GB. Source: Euronews

[29] According to EirGrid estimates, oversupply peaks in 2027/28, and starts to decrease after that (estimates are only to 2030). Increased demand and interconnection, especially with France, are expected to decreased the oversupply. Source: EirGrid (Q4 2022), *Enduring Connection Policy 2.2*, Available here

[30] Government of Ireland (May 2023), Terms and Conditions for the Third Competition under the Renewable Electricity Support Scheme. Available here

[31] Stanley et al (2023), Strategies to increase grid flexibility for an isolated system with over 80% of renewable electricity in 2030. Available here

7. Market conditions that may affect Irish deployment of VRE

This section briefly covers market factors such as required investment, labour and skills for decarbonising the Irish power sector and technology cost trajectories.

Required investment

A rapid increase in renewable generation in Ireland will require a step change in the required investment. *Table 3* summarises a recent estimate of the additional investment required in renewable generation to meet the 2030 renewable electricity targets.[32] Reliable estimates for historic investment in renewable generation in Ireland are not publicly available. However, over the past 15 years, approximately 5.4 GW of wind and solar PV capacity have been installed. This represents about a quarter of the total capacity needed to meet the 2030 renewable electricity targets. These figures highlight the significant increase in investment required to reach these goals.

Table 3: Scale of required investment to meet 2030 RES-E targets

	Gap to 2030 target	Required investment
Offshore wind	5 GW	€15 billion
Onshore wind	4 GW	€5 billion
Solar	6 GW	€4 billion
Back-up capacity		€1 billion
Grid		€14 billion
Storage		€4 billion
Total renewable generation		€43 billion

Source: Davy (November 2023), Investing in Tomorrow: Shaping a Net-Zero Future. Available here

Cost differentials between technologies

Cost differentials in the levelised cost of energy (LCOE) can influence various aspects of renewable energy policy and demand. These include Government support for technology-specific policies, market demand for renewable generation as a decarbonisation strategy, and the selection of specific variable renewable energy (VRE) technologies to meet RES-E targets. Additionally, these trends impact corporate demand for renewable electricity, such as through corporate power purchase agreements (CPPAs).

[32] Davy (November 2023), Investing in Tomorrow: Shaping a Net-Zero Future. Available here

Figure 8 below shows changes in LCOE by technology for 2010 and 2022. The comparatively high cost of energy from fossil fuel has been a key driver of the deployment of renewables. Since 2010, the global weighted-average levelised cost of energy (LCOE) for onshore wind has decreased significantly. It was initially 95% higher than the lowest-cost fossil fuel-fired electricity. Today, it is 52% lower than the cheapest fossil fuel-fired alternatives. Over the same period, solar PV went from being 710% more expensive than the cheapest fossil fuel-fired solution to costing 29% less than the cheapest fossil fuel-fired solution.

Figure 8: LCOE by technology

	Levelised cost of electricity (2022 USD/kWh)		
	2010	2022	Percent change
Bioenergy	0.082	0.061	-25%
Geothermal	0.053	0.056	6%
Hydropower	0.042	0.061	47%
Solar PV	0.445	0.049	-89%
CSP	0.380	0.118	-69%
Onshore wind	0.107	0.033	-69%
Offshore wind	0.197	0.081	-59%

Source: *IRENA, Flexible Power Generation Costs in 2022, Available here*

Although the global levelised costs of energy (LCOE) for onshore wind, offshore wind, and solar PV have decreased significantly, trends vary across different markets. Some markets have experienced cost reductions, while others have experienced cost increases. Recently, solar PV costs increased by 34% in France and Germany, and 51% in Greece, driven by rising PV module and commodity prices at the end of 2021 and into 2022. Some of this variability represents the normal variation in individual project costs, but it is likely that commodity and labour cost inflation had a significant impact on some markets. The IEA estimates that electricity generation costs from new utility-scale onshore wind and solar PV plants are likely to remain 10–15% above pre Covid-19 values in most markets outside China in 2024. This is due to commodity and freight prices and increases in developers' financing costs due to rising interest rates.[33] Furthermore, LCOE's for projects in Ireland may differ from international averages because of multiple local factors, including land leasing costs, local authority rates and development levies, and grid costs.

In the ROI (and shifting from LCOE to auction prices), since 2020, the combined weighted average strike price for onshore wind and solar PV increased significantly in successive RESS auctions, from €74/MWh (RESS-1, 2020), to €98/MWh (RESS-2, 2022) and €100/MWh (RESS-3, 2023). In 2023, offshore wind came in at €86/MWh (ORESS, 2023), lower than the average combined strike price across solar PV and onshore wind in the same year. The aforementioned prices may also be strongly influenced by the auction terms and conditions and how these allocate risks.

[33] IEA (June 2023), Will solar PV and wind costs finally begin to fall again in 2023 and 2024? Available here

Routes to market

The Government supports onshore wind and solar PV via the Renewable Energy Support Scheme (RESS).[34] In order to qualify to compete in RESS, developers must have planning permission and a grid connection offer or agreement. The Programme for Government commits to holding RESS auctions at frequent intervals. To date, there have been three RESS auctions, details of which are summarised in *Table 4* below. The next auction (RESS-4) is scheduled for Q4 2024. The current final scheduled auction is RESS 5 in 2025, but it is expected that RESS will be extended beyond this timeframe.

Table 4: RESS 1, 2, and 3 auction outcomes

	RESS 1	RESS 2	RESS 3
Successful onshore wind projects	19	14	3
Volumes – capacity	479 MW	414 MW	148 MW
Successful solar projects	63	66	20
Volumes – capacity (solar)	769 MW	1,534 MW	498 MW
Price[35]	€74.08/MWh	€97.87/MWh	€100.47 MWh

Source – EirGrid (June 2023), ORESS 1 Final auction results. Available here

RESS is not the only route to market for onshore wind. One key alternative is the corporate power purchase agreement (CPPA).[36] In Ireland, CPPAs are commonly used by large corporate users, such as data centres, and these agreements have primarily involved onshore wind, with solar becoming more prominent in recent years.

Offshore wind power generation in Ireland is supported via the Offshore Renewable Electricity Support Scheme (ORESS). The first ORESS auction (ORESS 1) was held in 2023.[37] Six projects qualified to participate in the auction, and four of those projects received Contracts for Difference (CfD) offers (*Table 5*).[38] The auction awarded a total capacity of 3.1 GW at a weighted average price was €86.05 per MWh.[39]

[34] Government of Ireland (2019), Renewable Electricity Support Scheme: High Level Design. Available here
[35] i.e. Weighted Average Strike Price of Successful Offers including solar PV and wind power.
[36] Government of Ireland (March 2022), Renewable Electricity Corporate Power Purchase Agreements Roadmap. Available here
[37] In early 2022, six offshore wind projects, comprising nearly 4GW, that had already had a longer history of development (i.e. had either obtained planning consent, or a grid connection offer, or had conducted significant development under a foreshore licence) were fast tracked for ORESS. Five of these projects are in the Irish Sea, the Sceirde Rocks project is off the Galway coast.
[38] EirGrid (June 2023), RES – ORESS 1 Final Auction Results. Available here
[39] EirGrid (June 2023), RES – ORESS 1 Final Auction Results. Available here

Table 5: Successful ORESS 1 projects

Successful applicant	Project	Offer quantity
Kish Offshore and Bray Offshore Wind Limited	Dublin Array	824 MW
Fuinneamh Sceirde Teoranta	Sceirde Rocks Offshore Wind Farm	450 MW
North Irish Sea Array Windfarm Limited	North Irish Sea Array (NISA)	500 MW
Codling Wind Park Limited	Codling Wind Park	1,300 MW

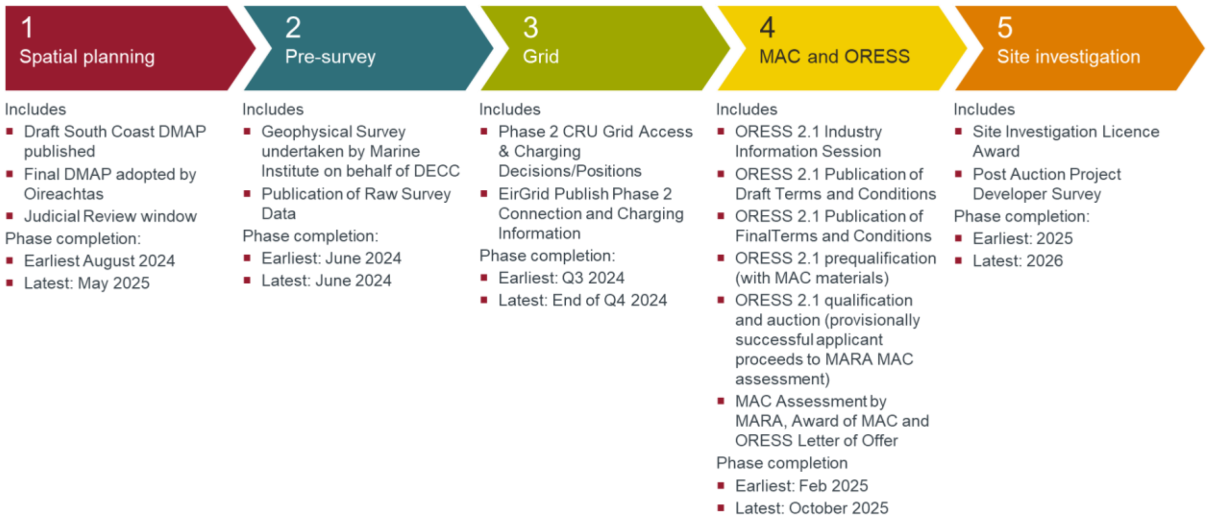
Source: EirGrid, ORESS 1 Final Auction Results

To date, none of the ORESS 1 winners have received planning permission and it is possible that one or more projects may face judicial review.[40] The ORESS 1 projects must start generating electricity by 31 December 2031, though extensions are possible if a project falls under the judicial review clause (clause 7.3) of the terms and conditions.

In 2023, the Government issued a policy statement for future ORESS auctions. The next ORESS auction (ORESS 2.1) is provisionally scheduled for February-June 2025. Currently, the Government proposes to procure up to 900 MW from this auction. Importantly, the auction will be spatially restricted to projects within a state-designated DMAP off Ireland's south coast. This area has been chosen as it aligns with existing available onshore grid capacity identified by EirGrid.[41] The DMAP has not yet been published and the auction process will only proceed once the Oireachtas approves the DMAP under the MAP Act. The Government also anticipates the possibility of a judicial review of the DMAP (included in the aforementioned scheduled date). The Government envisages that subsequent Phase 2 auctions (after ORESS 2.1) will exclusively procure offshore wind capacity from a single auction winner within individual DMAPs.[42]

[40] To participate in the ORESS 1 auction, developers needed a MAC, but did not need planning permission.
[41] Government of Ireland (2023), South Coast Offshore Renewable Energy Designated Maritime Area Plan Proposal. Available here
[42] Government of Ireland (March 2023), Accelerating Ireland's Offshore Energy Programme: Policy Statement on the Framework for Phase Two Offshore Wind. Available here

Figure 9: Summary of ORESS 2.1 indicative roadmap



Source: Government of Ireland, ORESS 2.1 Indicative Roadmap. Available here

Finally, the Government has also published the intentions for Phase 3 ORESS auctions. It is envisaged that an initial 2 GW of floating offshore wind capacity will be procured off Ireland's south and west coasts, and may include projects available for green hydrogen production and other non-grid uses. In the longer term, the Government plans to establish an 'Enduring Regime' for offshore wind, increasing state involvement in developing Ireland's offshore renewable energy sector. This includes designating maritime zones for future projects, scheduling development timelines, and determining the optimal mix of offshore renewable energy technologies.

In addition to the ORESS, corporate power purchase agreements (CPPAs) present another route to market.[43] [20] No offshore wind farm has yet made use of a CPPA to access the Irish market. The requirements for CCPA-supported offshore wind projects to receive gird connection offers is currently unclear. In the future, it is possible that offshore wind projects in Irish waters may follow the approach of "revenue stacking", where developers contract a certain proportion of their output under renewable subsidy schemes (similar to ORESS), and a certain proportion of their output under a CPPA and/or a merchant operation.

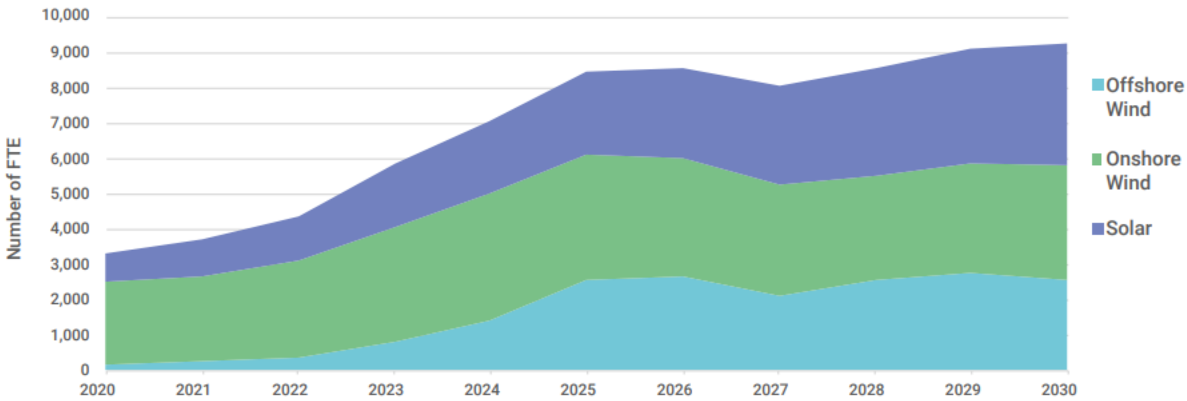
[43] Government of Ireland (March 2022), Renewable Electricity Power Purchase Agreements Roadmap. Available here

Irish labour market, skills needed for deployment of VRE generation in Ireland

A skilled labour force is a key enabler for transitioning the economy to net zero. Some of the required skills will be common across technologies, while other skills will differ by technology deployed. In order to reach national RES-E targets, a significant increase in the supply of a range of existing skills and occupations as well as a change in the skills mix is required.[44]

Figure 10 shows the modelled labour demand expected from offshore wind, onshore wind and grid-scale solar over the 2020–2030 period based on meeting renewables targets.[45]

Figure 10: Modelled labour demand from offshore wind, onshore wind, and grid-scale solar energy, 2021–2030



Source: Skillnet Ireland, https://skillsireland.ie/all-publications/2021/5119-dete-egfsn-skills-for-zero-carbon-web_.pdf,

Labour supply allocated to offshore wind, onshore wind and grid-scale solar would have to triple from approximately 3,500 FTE per year in 2020 to over 9,000 FTE per annum in 2030. As onshore wind is a comparatively mature industry in Ireland, most of this growth in labour demand is expected to come from offshore wind and solar, with more moderate growth in onshore wind. Grid-scale solar PV has the largest growth in FTE labour demand. This is because solar is the most labour-intensive of the three sectors relative to installed capacity, reflecting the small scale of most solar farms in comparison to wind. *Figure 11* shows this FTE labour demand in terms of the main occupational groups. By 2030, the main occupational groups are expected to be construction and installation occupations (approx. 3,200 FTE), technicians and technical professionals including maintenance technicians (1,900 FTE), and engineering professionals (1,300 FTE). An existing overall shortage in construction occupations may constrain activity in the renewable energy sector.[46]

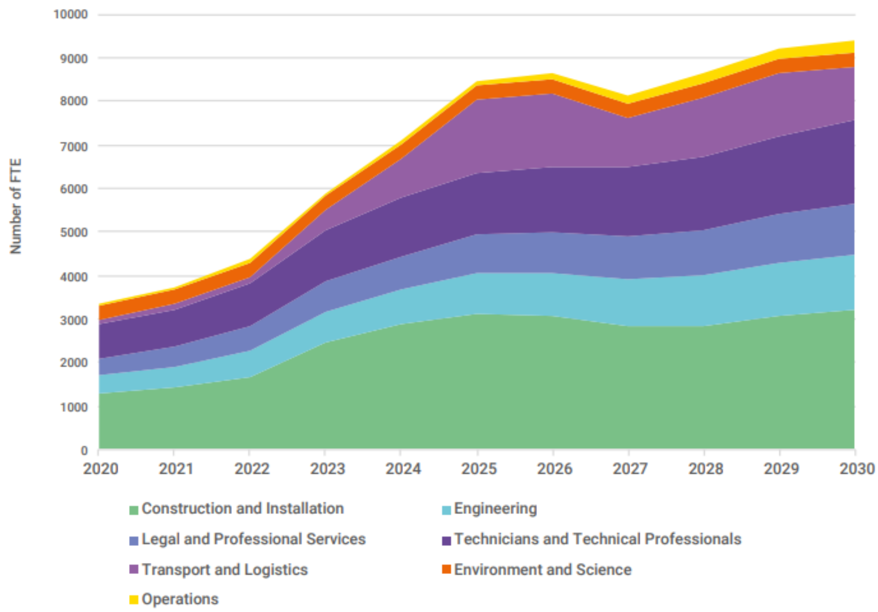
[44] Joint Committee on Enterprise, Trade and Employment (March 2023), Report on offshore renewable energy. Available here

[45] It is based on the modelled cumulative installed capacity of offshore wind, onshore wind and solar energy: an additional 5GW of new offshore wind, 4GW of new onshore wind, and 2.9GW of new grid-scale solar energy by 2030. Increases in small-scale residential solar installations were captured separately within another model for retro-fits. Labour requirements are expressed in terms of 'Full-Time Equivalents' (FTE), which approximates the number of full-time workers that would be required to meet the labour demand.

[46] Upskilling in construction occupations is especially challenging given the pipeline of work that was suspended during COVID-19 workplace closures. The National Skills Bulletin 2022 identifies significant implications for construction-related skills from the transition to a zero-carbon economy. While a small number of relatively new occupations (e.g. wind turbine technician, retrofit coordinator) are likely to grow in size, the most significant impact will be changes in the skills mix of a range of existing occupations (e.g. civil engineers, plumbers, roofers, glaziers, etc) as well as an increased demand for some existing ones.

[47] [48] Furthermore, a particular acute shortage in electrical trades may emerge because of Government policies to support multiple areas of the energy sector, including the deployment of heat pumps, EVs, domestic solar PV, wind and solar farms, and grid infrastructure. Such a deficit might not be addressed by short-term retraining.

Figure 11: Modelled labour demand from renewable energy by broad occupational group, 2021–2030



Source – Skillnet Ireland, https://skillsireland.ie/all-publications/2021/5119-dete-egfsn-skills-for-zero-carbon-web_.pdf,

For offshore wind, the required upskilling is estimated to exceed what the Irish market can deliver within the timeframe needed to meet the current target.[49] [8]

In addition to the increase in volume and specialisation for skills in the renewable sector, there are also concerns over a lack of capacity in the National Parks and Wildlife Service and An Bord Pleanála. In 2022, An Bord Pleanála issued a public apology for not meeting statutory time frames for decisions on "a large number" of planning cases. Planning applications for onshore wind farms are supposed to be decided by An Bord Pleanála within 18 weeks but, on average, it is taking over a year. This is largely due to a lack of capacity[50]

[47] Solas (2022), National Skills Bulletin 2022. Available here
[48] National Skills Council (November 2021), Skills for Zero Carbon: The Demand for Renewable Energy, Residential Retrofit and Electric Vehicle Deployment Skills to 2030. Available here
[49] Dublin Offshore (July 2022), Growth of onshore to offshore wind – Atlantic Region Wind Energy & Supply Chain Feasibility Study. Available here

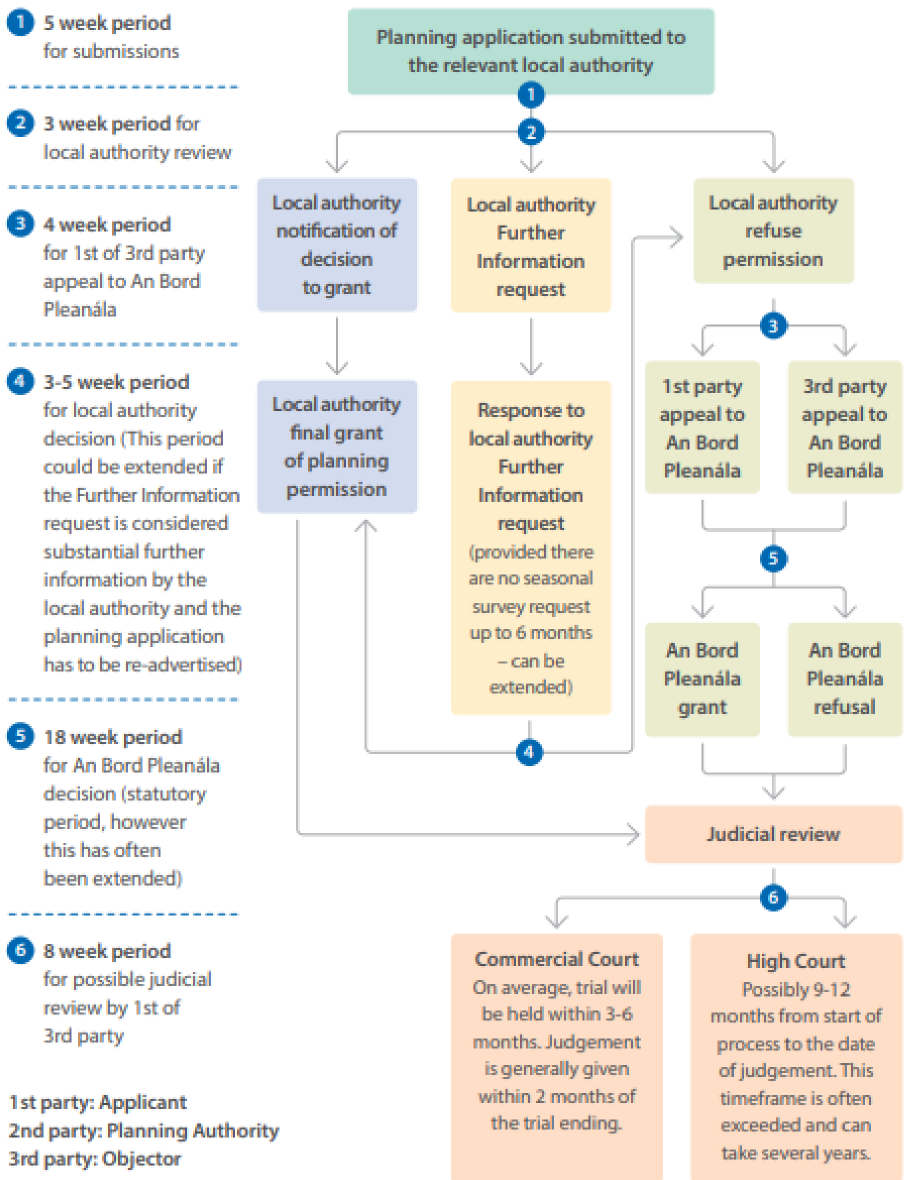
[50] Planner (February 2023), An Bord Pleanála governance probe continues. Available here

8. Planning consent and the planning process

Planning has been identified by wind industry stakeholders as the greatest barrier to the development of renewable projects in Ireland.[51] As of November 2023, it had been more than a year since the last onshore wind farm was granted planning permission.[52] This is driven by a combination of factors including An Bord Pleanála timelines and judicial reviews.

The current planning process for onshore renewables is outlined in Figure 12 . This does not apply to Strategic Infrastructure Developments (SID).

Figure 12: Summary of planning application process



Source: SEAI

[51] Wind Energy Ireland (2023), Wind Energy Ireland Poll – 'What do you believe is the single biggest challenge to building wind farms in Ireland? Available here

[52] Davy (November 2023), Investing in Tomorrow: Shaping a Net-Zero Future. Available here

Planning requirements for onshore wind is currently being reviewed. The Planning and Development 2023 Bill was recently published and includes an intention to restructure An Bord Pleanála, impose strict time periods for planning decisions; and reform the judicial review procedure. The Government is also expected to publish revised Wind Energy Development Guidelines for onshore wind in Q4 2024, which will include updated guidelines for setback distances and noise.

9. Supply chain

We discuss the supply chain for onshore wind and solar PV in this section. Specific supply chain points for offshore wind are included in Section 11.

Onshore wind supply chain

Many high-value niches in the onshore wind supply chain are being captured by Irish companies.[53] Irish companies could capture around half of the investment in onshore wind energy, particularly during the planning, installation and quality-assurance stages. Most professional and engineering services are expected to be locally sourced, although some technical specialists are likely to be drawn in from neighbouring countries.

Due to the lack of a heavy manufacturing base in Ireland, 13% of total investment in onshore wind is expected to be associated with manufactured imports. In general, the areas of the supply chain that are less well positioned to capture investment are those where there is no significant manufacturing base in Ireland or where the small Irish market size inhibits early growth. Future opportunities have been identified in areas such as equipment repairs, where manufacturers may establish local service centres if market demand is sufficient. Additional potential lies in the production of smaller components, including controls, gearboxes, transformers, and generators.

In addition, there are opportunities for companies that have developed and refined their business model in the Irish wind energy sector to expand their business to other markets. Examples of companies that have done this are wind-farm development companies such as Airtricity and Mainstream Renewables, meteorological monitoring company Wind Measurement International, and specialist ICT companies such as ServusNet, BrightWind and EnergyPro. The provision of ICT based services to the international wind energy sector is well matched to exploiting Ireland's strong competences in ICT.

Solar supply chain

In general, the areas of the supply chain considered to be poorly positioned to capture investment are those where there is no significant manufacturing base in Ireland, which includes solar panels.[54] There are a few niches, largely in R&D, where the ROI could capture value from a growing international PV market in the future.[55]

10. Social acceptance

Two independent studies recently noted widespread support for offshore wind amongst Irish coastal

[53] SEAI (2014), Ireland's Sustainable Energy Supply Chain Opportunity. Available here
[54] Dublin Offshore (July 2022), Growth of onshore to offshore wind – Atlantic Region Wind Energy & Supply Chain Feasibility Study. Available here
[55] SEAI (April 2017), Ireland's solar value chain opportunity. Available here

communities.[56] [57] Most coastal residents would prefer the Government to reach its offshore wind energy target for 2030 and do not think visibility of offshore wind will affect their enjoyment of coastal activities. However, coastal residents (on average) prefer offshore wind farms to be further from the shore (at least 15km). A few networked opposition groups are actively advocating against some of the Phase 1 projects or for a general setback distance for all offshore wind projects. While these groups present views from a small minority, it is anticipated that judicial reviews will be lodged for some of the Phase 1 projects given their proximity to the coastline, concerns over procedural injustice, and/or contestation over the conservation status of some of the east coast sand banks. The Government also anticipates judicial review of forthcoming DMAPs. This may delay deployment of some Phase 1 projects and/or the scheduling of future ORESS auctions under Phase 2 of the Government's offshore energy programme.

A strong majority of the Irish public residing in rural areas have positive attitudes towards onshore wind, regardless of how close they are to wind projects.[58] 65% of people who live next to (less than 1km from) a new wind farm or far away (more than 10km) believe that Ireland has too few wind farms and that more should be built. This number falls to 52% for those who live near new wind farms (1-5km). Approximately eight out of ten rural residents think Ireland has too few solar PV farms, regardless of their proximity to new solar PV projects. About one in eight people who live in rural areas have a negative attitude towards onshore wind farms in general. Only 4% of rural residents have a negative attitude towards solar PV farms in general. Those who have such attitudes are much more likely to take action(s) regarding a local wind/solar farm.

However, one in three people who live near a new wind farm project and one in five people living near a new solar PV project (1-5km) in Ireland do not believe they can have a say in the planning process, and a slightly larger proportion believe that developers and the planning authorities do not take account of the opinions of communities near projects. Most people residing in rural areas do not think the planning process in Ireland is fair and transparent, regardless of their proximity to new wind or solar farm projects.

There is currently no reliable, publicly available data on the trends in judicial reviews lodged against wind or solar farms planning consent.

11. Offshore wind

As of 2024, there is only one 25 MW demonstration project operational in Irish waters. Since the early 2000s, a few industrial and policymakers have (at various points in time) advocated for its deployment. However, deploying this technology in the Irish context faced significant technical, legislative, regulatory, and economic challenges. These complexities extended the deployment timeline far beyond the expectations of some stakeholders.[59] However, by 2019, a consensus had been established between state agencies, system operators, the regulator and Irish generation market that the technology would be a necessary part of the required generation mix to meet a national 70% RES-E target.

[56] Cronin Y. et al. (2019). D4.4. Public Perception of Offshore Wind Farms Report Part 1. Available here.
[57] Roux, J. et al. (September 2022), Irish National Survey of Fisherman and Coastal Residents on Offshore Wind Energy. Available here
[58] SEAI (May 2023), Irish national survey of household near new commercial wind and solar farms. Available here
[59] Roux, J. et al. (2022), "We could have been leaders": The rise and fall of offshore wind energy on the political agenda in Ireland. Available here.

Existing policy measures to enable offshore wind energy

This section summarises existing policy measures, including targets and policy coordination, marine planning and consenting, and grid connection policies and plans.

Targets and policy coordination

Since 2019, successive governments have issued increasingly ambitious targets for offshore wind power deployment by 2030 and 2050.[60] These targets serve as a necessary and import signal of intent to other actors and serve to calibrate related policies towards target attainment. However, it cannot be assumed that they will be met. The Government has established a cross-departmental Offshore Wind Delivery Taskforce to implement a singular, system-wide strategy and road map for all the activities required to meet the medium-term targets and provide oversight and reporting on delivery. Key areas of this plan are summarised below.

Marine planning and consenting legislation and policies

In recent years, several significant updates to the legal framework for marine planning and consenting have sought to facilitate the deployment of offshore wind power.

- The National Marine Planning Framework (NMPF) provides an overarching framework that sets a direction for managing Irish seas and objectives for progressing offshore wind power deployment alongside other maritime sectors.[61]
- The Maritime Area Planning (MAP) Act 2021 provides the legal underpinning to the new marine planning system, and provides further clarity to developers on the offshore wind development management system for projects in Ireland's maritime area.
- In accordance with the MAP Act 2021, the Maritime Area Regulatory Authority (MARA) was established in 2023. MARA has responsibility for assessing applications for maritime area consents (MACs), which will be required before offshore wind project developers can make a planning application.
- Furthermore, the MAP Act sets out the process for establishing Designated Maritime Area Plans (DMAPs) that will determine the spatial zones where offshore renewable energy projects can be developed as the planning regime shifts from the historical 'developer led' approach to a 'plan-led' spatial planning approach.[62]
- In addition to MACs, offshore wind projects also need to obtain planning consent from An Bord Pleanála.

Grid connection policies and grid development plans

The ability for offshore wind projects to secure grid connection is driven by availability of capacity on the grid. Grid capacity can be split into existing capacity and future capacity, the latter enabled by investments in grid infrastructure, such as reinforcement projects.

ORESS 1 project developers are required to build their own offshore grid transmission infrastructure to connect their projects to the grid, ownership of which will then be transferred to EirGrid. The first wave of offshore wind projects will rely on existing grid capacity. All ORESS 1 projects have a valid Grid Connection Assessments and therefore are expected to be able to connect to the grid. For ORESS 2.1, the grid connection policy is yet to be finalised, but the CRU's proposed decision is that EirGrid will issue feasibility

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[60] Government of Ireland (March 2023), Accelerating Ireland's Offshore Energy Programme: Policy Statement on the Framework for Phase Two Offshore Wind. Available here

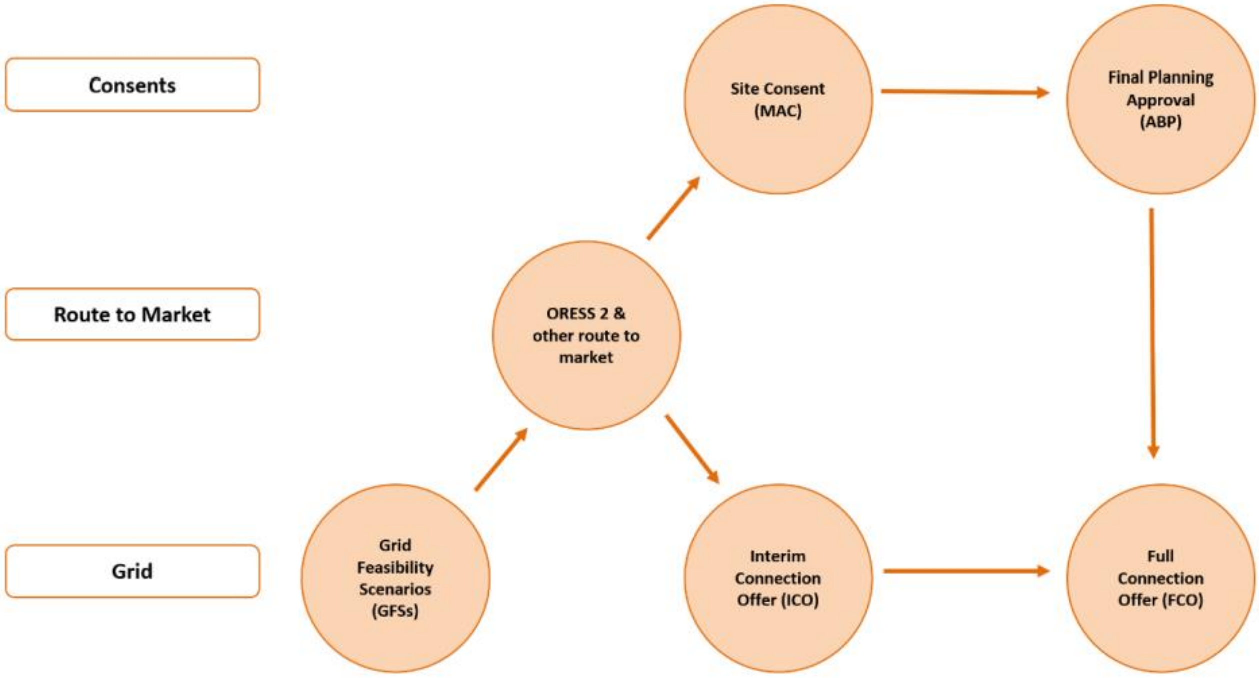
[61] Department of Housing (2021), Local Government and Heritage, National Marine Planning Framework

[62] Government of Ireland (2023), Designated Maritime Area Plan (DMAP) Proposal for Offshore Renewable Energy. Available here

scenarios that will align existing grid capacity with the DMAP and provide some expectation that a grid connection would be forthcoming.

However, to receive a grid connection offer, the regulator proposes that projects must be in possession of a MAC, a route to market (for example, successful ORESS bid); and final planning consent. The CRU's proposed approach to grid connection for Phase ʼ projects is summarised in *Figure 13*. EirGrid has a €3.3 billion capex programme, which is expected to enable further grid capacity in the coming years. Future DMAPs, and hence future offshore wind developments, are expected to align with that grid development.

Figure 13: CRU's proposed grid connection pathway for ORESS 2



Source: CRU

Pipeline of project in Irish waters

In 2022, Wind Energy Ireland (WEI) estimated that there was a pipeline of projects totalling 28 GW competing for 2030 delivery. This included 16 projects totalling 13 GW off the east coast, 10 projects totalling 10 GW off the south coast, and six projects totalling 5GW off the west coast. The majority of projects currently publicly declared on the Atlantic coast are focused on access to the Moneypoint grid connection, which is anticipated to become available from 2025.[63]

Currently, there are at least seven floating offshore wind farm projects in the Atlantic region in the very early stages of planning. Future installed floating offshore capacity may be related to upgrades in grid connection availability, or potentially production of green hydrogen as a vector fuel. Combined fixed and floating offshore wind projects are also planned off the Sligo and Donegal coasts in the North-West region and are at an early stage of project definition and planning.

International factors

The Irish supply chain for bottom-fixed offshore wind is immature and deployment in Ireland is likely to remain dependent on international supply chains for the foreseeable future.[64] [65] [66] Only with an aggressive approach to ensure local content could it capture a limited proportion of the total value of a windfarm project. This would be largely from providing technical surveying services (during the project development and consent phase) and from vessel provision, vessel services and associated equipment supply during the operation and maintenance stage.[67] There is currently no signal from the Irish Government that it is considering introducing local content requirements.

A shortage of specialised offshore vessels in particular presents a risk to deployment of offshore wind energy in Ireland in the short-term.[68] The availability of specialised vessels required for the transport of turbine elements, and the installation and maintenance of offshore wind farms is currently a bottleneck in the international supply chain.[69] [70] By 2025, it is expected that the demand for installation and cable laying vessels will outstrip the supply.[71]

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63 Dublin Offshore (July 2022), Growth of onshore to offshore wind – Atlantic Region Wind Energy & Supply Chain Feasibility Study. Available here

64 Wind Energy Ireland, Working together, Building Ireland's offshore wind industry. Available here

65 Carbon Trust (May 2020), Harnessing our potential – Investment and jobs in Ireland's offshore wind industry. Available here

66 SEAI (2014), Ireland's Sustainable Energy Supply Chain Opportunity. Available here

67 Carbon Trust (May 2020), Harnessing our potential – Investment and jobs in Ireland's offshore wind industry. Available here

68 Bottom-fixed offshore wind requires specialist heavy-lifting and cable installation vessels whereas floating offshore wind may require less sophisticated, lower cost vessels for installing the turbine units and floating substations – specialist vessels are likely needed for installing mooring systems and dynamic cables. Various other vessels are used for surveys, equipment swaps, and crew access. Due to the metocean conditions in the Atlantic it is unlikely access to the platforms will be provided through traditional Crew Transfer Vessels (CTV). Service operation vessels (SOV) will provide a more appropriate weather window for personnel access to effect maintenance.

69 Dublin Offshore (July 2022), Growth of onshore to offshore wind – Atlantic Region Wind Energy & Supply Chain Feasibility Study. Available here

70 Carbon Trust (May 2020), Harnessing our potential – Investment and jobs in Ireland's offshore wind industry. Available here

71 Wind Europe (June 2022), Europe's offshore wind expansion will depend on vessel availability. Available here

The current macro-economic environment across advanced economies also present a risk to offshore wind deployment, at least in the next five years.[72] Since 2022, central banks have increase base interest rates while inflation has remained relatively high. Investment costs in offshore wind is 20% higher today than a few years ago. In 2023, developers cancelled or postponed 15 GW of offshore wind projects in the United States and the United Kingdom. For some developers, pricing for previously awarded capacity does not reflect the increased costs facing project development today, which reduces project bankability. Policies in some jurisdictions have been relatively slow to adjust to the new macroeconomic environment which has left several auctions in advanced economies undersubscribed, particularly in Europe.

Green hydrogen

It is possible that the production of green hydrogen may become a driver for increased offshore wind deployment in Ireland. Government analysis indicate that hydrogen could be produced from grid-connected electrolysis from surplus renewables prior to 2030, if the 80% RES-E target is met. In the 2030s, the Government envisions allocating some offshore wind capacity exclusively for green hydrogen production using off-grid electrolysers.[73]

For hydrogen to be a valuable fuel (and hence drive greater deployment of renewables), many other developments need to happen in other aspects of the hydrogen supply chain, including transportation, storage, and demand. Initially, hydrogen is likely to be transported by truck or used onsite. Blending hydrogen into the gas transmission system is also a challenging mitigation measure. [74] Hydrogen pipelines (local, and then national) will need to be developed to enable production, storage and usage at scale. The National Hydrogen Strategy envisages that small-scale storage applications are most likely until 2033, after which large-scale storage (and transport) will be developed. However, large-scale hydrogen storage sites may conflict with CO_2 storage, for example, the Kinsale Area gas fields. The national strategy envisages that demand for hydrogen will grow in the 2030, starting with heavy-duty transport, then industry and power generation (2030-2035), and followed by aviation and maritime end-users (estimated 2035-2040).

Grid-connected electrolysers[75] come with both advantages and disadvantages . Hydrogen can be considered green if produced during periods of dispatch down.[76] However, using exclusively curtailed electricity may lead to low run hours, resulting in a high Levelised Cost of Hydrogen (LCOH). Furthermore, there is no constant or guaranteed production of hydrogen, posing potential challenges depending on demand and storage options. Moreover, these electrolysers add an additional load to an already pressured grid. To address this, EirGrid may need to develop a grid connection policy for prioritisation, and not all electrolysers will be easily connected.

Off-grid electrolysers powered by offshore wind (or other renewable sources) avoid placing additional strain on the electricity grid. However, the only source of revenue for the dedicated RES plant and electrolysers will be the sale of hydrogen, as no electricity and system services are provided. Moreover, the production of hydrogen relies solely on the RES provided by the dedicated plant. Therefore, this business model is highly dependent on hydrogen demand and prices. For these electrolysers to be profitable, they must be located in

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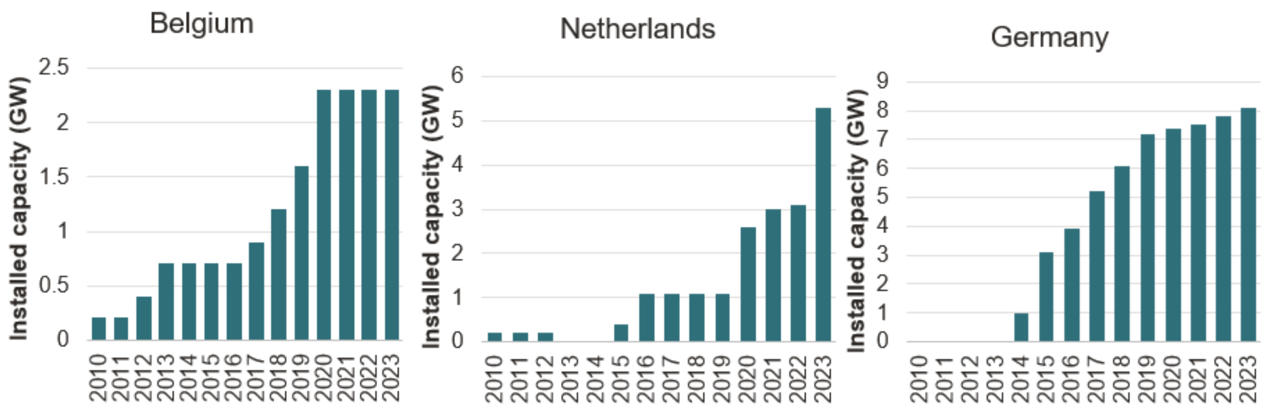
[72] IEA (2023), Renewable 2023: Analysis and forecast to 2029. Available here
[73] The National Hydrogen Strategy echoed these targets
[74] Hydrogen-blending yields a convex (sub optimal) carbon reduction due to its lower volumetric energy density.
[75] Grid-connected electrolysers can operate under various business models, but the focus here is on the curtailment model. That is, electrolysers run during periods of high wind to reduce dispatch-down in the system, aligning with DECC's vision for the near future.
[76] European Commission (2023), Directive 2023/2413 (Renewable Energy Directive). Available here

areas with high renewable production potential, feasible storage at large (geological) scale, and substantial demand. [77]

Selected examples from other jurisdictions

There is no historical deployment of offshore wind in Ireland from which to extrapolate indicative future deployment rates. *Figure 14* below shows the cumulative installed capacity of offshore wind in Belgium, the Netherlands and Germany. In all three countries, the installed capacity of offshore wind has increased substantially in the past decade. Care needs to be taken when comparing historical deployment rates across jurisdictions and drawing implications for possible future deployment in the ROI. Learning and economies of scale has significantly reduced the LCOE of offshore wind since 2010. For example, the strike price in the UK for offshore wind has dropped by about 70% over the last decade. These decreases in costs have often been greater than expected. The deployment rates in other jurisdictions were also influenced by different Government support instruments, planning regimes, historical industry (for example, ports and ship building), power market structure, and interconnection with neighbouring markets.

Figure 14: Offshore wind deployment



Source: *IEA, Renewable Energy Progress Tracker*

[77] According to the National Hydrogen Strategy, it is likely that many of these initial clusters could develop in the vicinity of commercial ports given their role in enabling offshore wind and typical proximity to potential large end users. The Strategy recognises that “Further work is needed to determine the optimal locations of these regional clusters. [...] . A decision on the locations of these early hydrogen clusters should be progressed in the early stages of implementation of this strategy”.

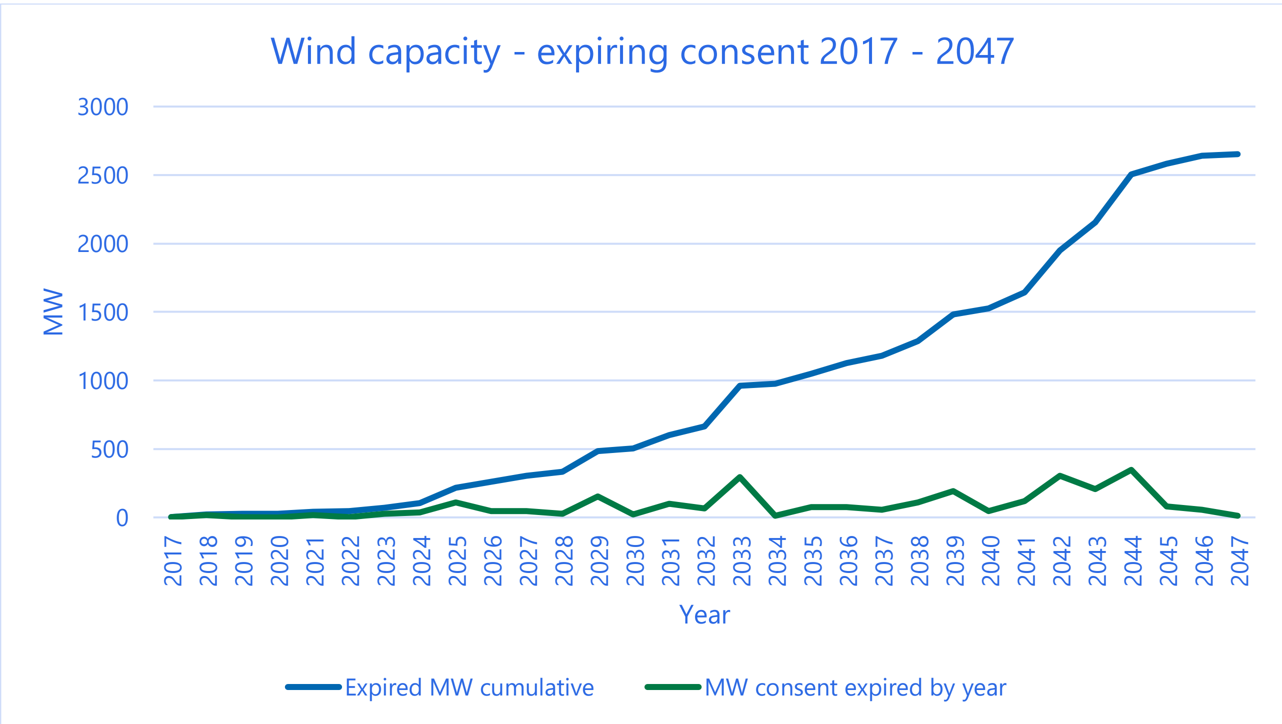
12. Onshore wind

In this section, the focus shifts to additional factors that could influence future deployment rates of onshore wind in Ireland. In Section 2, we provide an overview of the historical deployment of onshore wind power. Here, we delve deeper into specific aspects, including, expiration of planning consent for the older fleet, existing policy measures to enable onshore wind, national and international market conditions that may affect Irish deployment. This section also examines social acceptance, supply chain, and selected examples from other jurisdictions.

Expiration of planning consent on older fleet

Onshore wind has been deployed in Ireland since the 1990s. At some point the older fleet of Irish onshore wind farms will reach the end of their operational or planning consent life. These sites will have to be repowered or have a life extension, failing which the capacity will have to be decommissioned. *Figure 15* indicates that an increasing capacity will have to be replaced and/or reconsented. From 2026 to 2030, approximately 290 MW will expire. From 2031 to 2040, operational planning consent for just over 1 GW will expire.

Figure 15: Wind capacity - expiring consent, 2017–2047



Source: SEAI data (2022).

Existing policy measures to enable onshore wind

Targets

The Government has targets in place to increase onshore wind deployment by 2030. Under Ireland's Climate Action Plan, there is a target for 9 GW of onshore wind capacity by 2030.

Approach to policy coordination

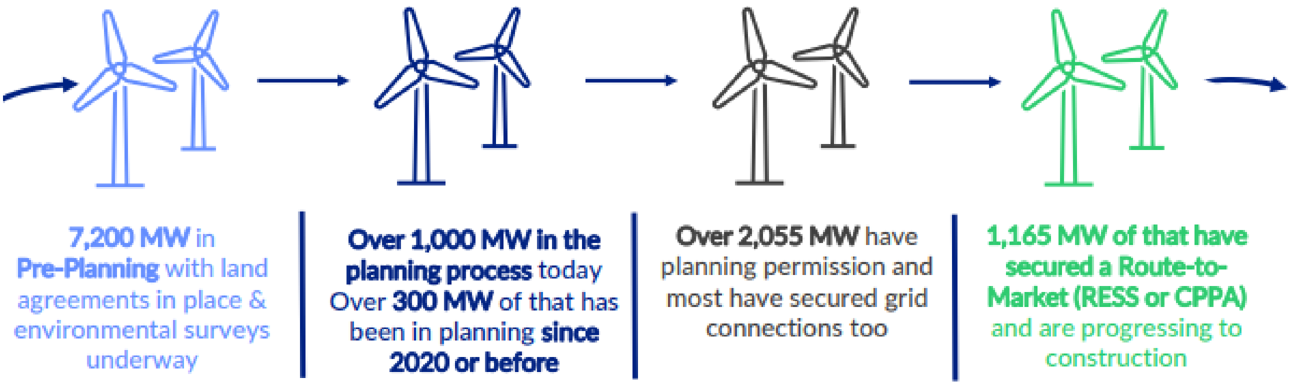
Climate Action Plan 2023 included an action to establish an Accelerating Renewable Electricity Taskforce to focus on the development of onshore renewable generation. The programme of work for this taskforce is expected in Q2 2024. It is expected that this taskforce's work will include addressing planning and grid-related constraints to further onshore wind deployment.

National and international market conditions that may affect Irish deployment

Current pipeline – onshore wind

Approximately 8,200 MW of onshore wind capacity is either in pre-planning or in the planning process, of which over 2 GW has planning permission, as shown in *Figure 16*. The stacked timelines of the planning application, grid connection, RESS, financial close, and project execution implies that pipeline delivery is weighted towards the end of the 2020s. This pipeline should be read alongside the figures for wind capacity that has a route to market (refer to *Table 4* pg.*15*) or have received grid connection offers under ECP (*Table 2* pg. 10) to estimate deployment rates up to 2030.

Figure 16: Onshore wind pipeline Ireland



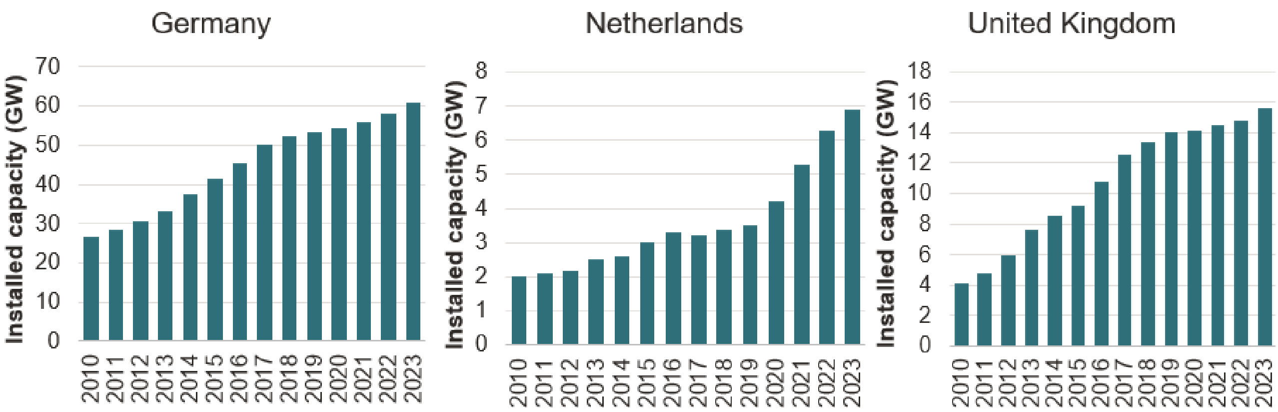
Source: Wind Energy Ireland (2022), Delivering Energy Independence for Ireland. Available here

Onshore wind deployment rates in other jurisdictions

There is a multi-decadal historical precedent for the deployment of onshore wind power in the Republic of Ireland (refer to *Figure 2* pg.5). However, it may also be useful to refer to deployment rates in other jurisdictions in contemplating plausible future scenarios for the ROI. A total of 204 GW of wind power capacity is installed in Europe EU 27 countries as of 2022, of which 88% (188 GW) is onshore.[78] Germany continues to have the largest installed wind power fleet in Europe with over 60 GW of installed capacity.

[78] Wind Europe website, Wind Energy in Europe: 2022 Statistics and the outlook for 2023-2027. Available here

Figure 17: Onshore wind installed capacity in Germany, the Netherlands, and the UK



Source: IEA, Renewable Energy Progress Tracker

Germany

Germany is currently, and is projected to remain, Europe's largest wind market over the next five years. The development of wind has been facilitated by subsidy support through auctions. Germany's latest onshore wind auction (2023) tendered 2.9 GW. The auction awarded 1.4 GW of new onshore wind projects at an average price of €73.4/MWh. Further, in 2023 alone 12.8 GW of onshore wind will be auctioned followed by 10 GW per year in the period 2024-2020. The main driver for this successful auction round is improved and streamlined permitting. In the first six months of 2023, Germany permitted 3.2 GW of new projects—a 44% increase year-on-year. In particular, the German Parliament adopted a new Onshore Wind Law (WindLandG) in 2022, which sets an installation target of 10 GW a year from 2025. Importantly, it also enshrines the principle that the expansion of renewables is a matter of overriding public interest and includes improvements to onshore wind permitting.[79]

Germany has also exempted certain renewables projects from environmental impact assessments. The EU emergency measures allow this for wind energy projects located in dedicated areas which have been subject to a wider strategic environmental assessment. Project developers in these cases do not have to complete the site-specific environmental impact assessment. Instead, they must take appropriate mitigation measures or pay into biodiversity protection programmes. The current revision of the Renewable Energy Directive (RED III) will permanently enshrine such acceleration areas into legislation.

Lastly, the German Government has implemented higher ceiling prices in onshore wind auctions in reaction to the struggles of the wind supply chain. The Government has authorised the Bundesnetzagentur, the agency overseeing renewables auctions, to increase the maximum ceiling prices for each auction round. This measure aims to ensure that projects remain economically viable and progress to completion.

The Netherlands

The Netherlands is a relatively early mover in the deployment of onshore wind. Its installed capacity was 8.8 GW as at end 2022, largely due to the increase of onshore capacity which grew by 18% and amounted to 6.3 GW. The installed capacity for onshore wind is shown below, broken down by turbine axis height.

Financial support from the Government has played an important role in the start-up of wind energy. In 2006, the Minister of Economic Affairs closed the most important subsidy scheme at the time, the Environmental

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[79] Wind Europe website (July 2023), Germany installed 1.6 GW new onshore wind in the first semester; rigorously implements permitting measure. Available here

Quality of Electricity Production Regulation (MEP), due to its great popularity and resulting financial obligations.

Support for existing and submitted projects continued and, in 2017, the last projects reached the end of the term of that support (RVO, 2017). As a successor to the MEP, a new subsidy scheme for new wind turbines was started in April 2008: the Incentive for Sustainable Energy Production scheme (SDE, SDE+ from 2011 and SDE++ from 2020). The subsidy covers the difference between the cost price and the average yield of wind energy per kilowatt hour. This subsidy scheme is now only available for onshore wind turbines.

The UK

Outside of the EU-27, the UK is a leading country in wind capacity and has almost 29 GW of installed capacity, of which just over 14 GW onshore capacity.[80] The UK is expected to install the most new wind power capacity over the next five years, second only to Germany in Europe. Most will be offshore installations (12.7 GW). [81]

Onshore wind build-out is expected to be 7.3 GW, with most of this likely to be built in Scotland due to the lasting effects of the de facto ban of onshore wind in England.

The UK had its fifth Contracts for Difference Allocation Round in 2023, the principal support mechanism for this technology. Bottom-fixed offshore competed against onshore wind and floating offshore competed in a separate pot for less mature technologies. The auction secured 3.7 GW of new renewable capacity, of which 1.9 GW onshore wind. This was considered disappointing; it was 82% lower than the auction held in 2022 and reflected large supply chain and inflationary pressures on wind and solar. [82] Onshore wind enjoys public support with support levels of up to 74% according to the UK Government's polls.[83]

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80 Drax Electric Insights. Available here

81 Wind Europe, *Wind Energy in Europe: 2022 Statistics and the outlook for 2023-2027. Available here*

82 *Carbon Brief, Analysis: UK renewable still cheaper than gas, despite auction setback for offshore wind*. Available here

83 Renewable UK (September 2022*). Polling in every constituency in Britain shows strong support for wind farms to drive down bills*. Available here

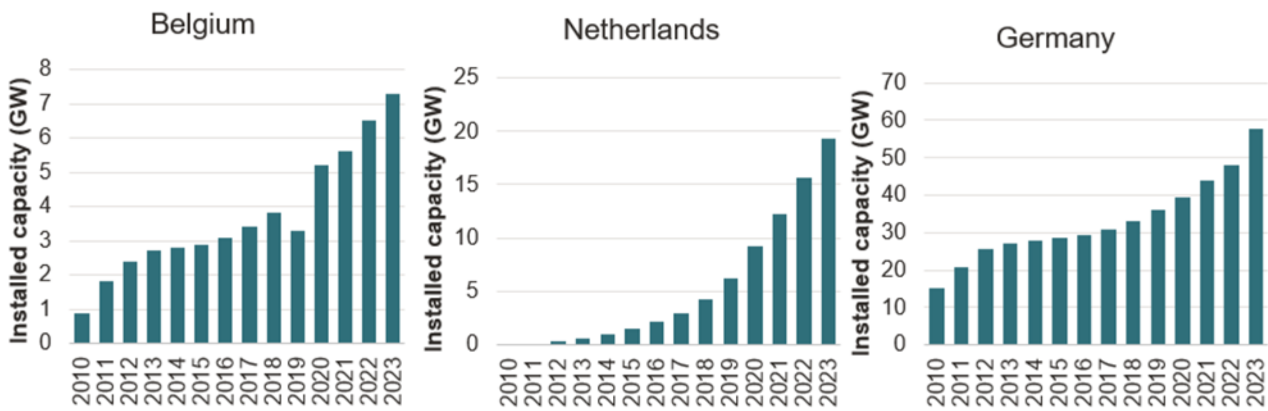
13. Solar

In this section, we consider the historical deployment of solar PV in other jurisdictions. In Section 1 (pg. 5) we provided an overview of the historical deployment of solar PV generation in the ROI. Additional factors that may affect future deployment are contained in the above sections. We cover the current routes to market for solar PV in Section 7, grid connection policy in Section 5, planning consent in Section 8, social acceptance in Section 10, and supply chain in Section 9. One omission of this brief is due consideration of the drivers of rooftop solar PV (micro generation) in the ROI.

Selected examples from other jurisdictions

Figure 18 below shows the historical deployment of solar PV in selected European solar PV markets.[84] Germany continues to be Europe's biggest solar market in 2022 (7.9 GW added), followed by Spain (7.5 GW), Poland (4.9 GW), the Netherlands (4.0 GW), and France (2.7 GW). In terms of solar power per capita, the Netherlands leads. In 2022, the Netherlands reached the remarkable milestone of more than 1,000 watt of installed solar power per inhabitant.

Figure 18: EU27 selected solar PV markets, 2021-22



Source – EU Market Outlook for Solar Power

Germany

Growth of solar PV in Germany slowed from 2013 to 2017, following the first growth phase driven by the feed-in tariff. Germany's solar sector is experiencing a second growth surge as of 2018. This is due to a combination of self-consumption with attractive feed-in premiums for medium- to large-scale commercial systems and auctions for systems up to 10 MW, and solar's steadily improving cost competitiveness. The Green Party-led Economy Ministry set a new 2030 solar target of 215 GW installed capacity and revised the Feed-in Law (EEG) in 2022, establishing improved investment conditions for the rooftop segment. The feed-in tariff for new systems has been increased, the monthly decreasing trajectory of feed-in rates for new systems is frozen until 2024, and the technical limit to input only 70% of rated power output was removed in January 2023. Furthermore, high electricity prices and the declining cost of batteries improved the business case for solar.

[84] Solar Power Europe, EU Market Outlook for solar power 2022-2026, Available here

The Netherlands

The Netherlands installed 4 GW in 2022, an increase of 11% from the previous year. Driven by a continuous attractive net-metering policy, the residential segment contributed most of this growth, with 1.8 GW of capacity additions. The Sustainable Energy Production and Climate Transition Incentive Scheme (SDE++) is the largest source of subsidy. In addition to the SDE++, here is also the Energy Investment Deduction (EIA) and the Sustainable Energy Investment Subsidy (ISDE) for business users.

Spain

Spain is experiencing a remarkable increase in capacity, bringing 7.5 GW to market in 2022, an increase of 55% from 4.8 GW in 2021. The utility-scale segment has been thriving for a while. The disappointing results of the auction that took place in November 2022, where no solar capacity was awarded despite 1.8 GW being initially allocated, must not be seen as a signal of lowered performance for the sector. Under the current energy market conditions, developers are selecting projects that sell their power on the free market, as this option is more attractive than government-run tenders. In contrast, the growth of rooftop solar only emerged after a prohibitive tax was discontinued in 2019. In 2022, the market more than doubled compared to 2021.

France

France added 2.7 GW of solar PV in 2022. A marginal decrease of 2% has been observed after the record-breaking 2021 performance, when the market grew 218% year-on-year. The increase in solar prices and difficulties in access to land observed in 2022 has led many developers to put projects on hold until economic and regulatory conditions improve. The commercial self-consumption segment, on the other hand, has increased its size, thanks to a revision of the policy framework in autumn 2021. At that point, the threshold for rooftop tenders increased from 100 to 500 kW, making more systems eligible for feed-in tariffs. Though still small compared to its European peers, residential solar is also gaining traction in the country.

Italy

In 2022, Italy added an estimated 2.6 GW, a 174% year-on-year growth following an extended period of slow growth. The small-scale solar PV segment has bolstered the market, thanks to the country's favourable Superbonus 110% incentive scheme and high electricity prices, which have improved the attractiveness of self-consumption business models. While permitting and identifying suitable land remains a key challenge for larger solar PV projects, positive steps towards simplified procedures are already being taken.

14. Green hydrogen for power generation: back-up dispatchable generation

Hydrogen-fired power generation has the potential to provide flexible, dispatchable backup energy in the future, playing a key role in helping Ireland meet its carbon emissions targets. However, significant uncertainties remain regarding future costs, as well as the required infrastructure, skills, and supply chains to support its implementation. This chapter summarises the factors driving and constraining future hydrogen power generation in the Irish power sector. When considering the potential deployment of green hydrogen power generation in Ireland, the full hydrogen value chain needs to be considered, including production, transformation, transport, storage and end use.

Hydrogen development in Ireland

Currently, Whitegate Refinery is the only significant domestic producer and user of hydrogen in Ireland. Here, hydrogen is used to produce gasoline, diesel, and Hydrotreated Vegetable Oil (HVO) fuel.[85]

In 2023, the Government set out its vision for the development of hydrogen in Ireland in the first National Hydrogen Strategy (NHS). It outlines a pathway to producing, distributing, and storing hydrogen, for different end uses. *Figure 19* shows the projected hydrogen demand figures in 2050 under high and low demand scenarios in the NHS. Since 2021, consecutive Climate Action Plans also included a target of 2 GW of offshore wind connected to electrolysers by 2030. However, the Irish wind industry does not believe the 2GW/2030 target is plausible, due to the exorbitant cost of producing hydrogen from offshore wind power.[86] Traditional least-cost approaches to energy system planning, as has broadly been followed in Ireland, will likely not result in the coupling of green hydrogen and offshore wind energy; rather, targeted policy will be required. Significant financial support will be critical to kickstarting the industry, either by bringing hydrogen costs in line with natural gas prices, or by paying the cost difference to consumers directly. [87]

Early development of hydrogen demand and supply in Ireland

Increasing demand for hydrogen in the short to medium-term may be influential in establishing a strong market for large scale hydrogen production and usage to be economically viable and technically feasible. Blending of hydrogen into the existing natural gas network and growing the market for bio and e-fuels present such opportunities.

As a precursor to use in the power sector, it is anticipated that hydrogen will first be used in long-haul transportation, maritime shipping, and industry.[88] A key uncertainty is therefore the extent to which this precursor market for hydrogen is established in Ireland and supplied by Irish production of hydrogen. The Whitegate Refinery could increase its production of hydrogen for biofuels such as HVO and fatty acid methyl esters, which can compete directly with fossil fuels. In 2022, the owner of the refinery, Irving Oil, signed a MoU with the Simply Blue Group to explore opportunities to develop a renewable energy hub that would integrate floating offshore wind generation (of the coast of Cork) with green hydrogen and e-fuel

[85] https://www.irvingoil.com/en-CA/press-room/irving-oil-launches-sustainable-energy-product-for-irish-customers
[86] Wind Energy Ireland (2022) Hydrogen and wind energy: the role of green hydrogen in Ireland's energy transition. Available here
[87] Aurora, available here
[88] https://www.gevernova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-overview.pdf

production.[89] However, given the noted electricity cost differential, it remains unclear if floating wind could compete with the LCOE from onshore wind and solar, even over the long term.

The initial transition from natural gas to hydrogen could also involve a degree of blending into the current gas network. A feasibility study by Gas Networks Ireland (GNI) found that the existing gas distribution system and half the transmission pipeline network is suitable for 100% hydrogen, but additional study is required to determine the suitability of equipment such as valves, meters and compressors.

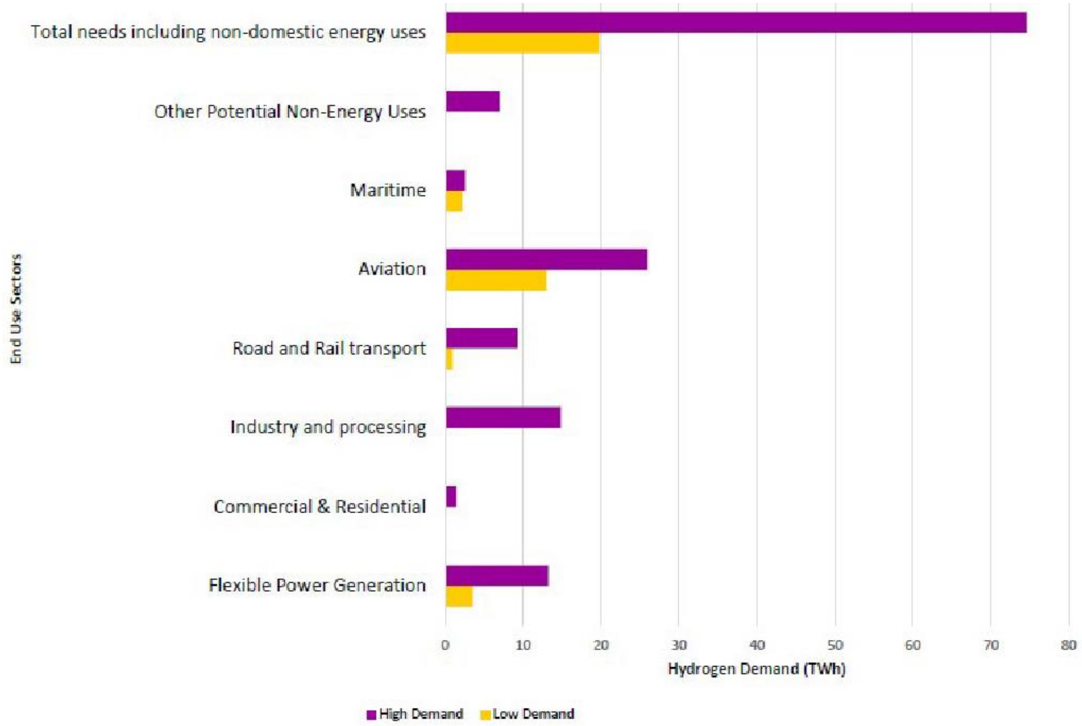
The Irish Academy of Engineering identifies potential challenges to blending hydrogen into the natural gas network.[90] Due to its smaller molecule size, hydrogen may leak from containers and fittings that are suitable for natural gas. It is also more reactive than natural gas, leading to higher rates of hydrogen embrittlement of steel pipes. Pipeline stresses could potentially be minimised if flows and pressures of hydrogen are held stable. However, this is not consistent with envisaged variability in hydrogen production that arises due to unpredictability in renewables generation capacity.

There are also challenges that end users must overcome for blending to be feasible. It is estimated that a 20% blend is the most that existing end users will be able to accept without requiring equipment modifications.[91] Some end users may need a constant blend of hydrogen, thus requiring significant storage of blends at potentially different mix levels. Finally, the EU hydrogen and Decarbonised Gas Market Package also requires members to be capable of accepting hydrogen blends at interconnection points, increasing the necessity for an internationally agreed approach to blending rates that represents the needs of end users.[92]

Although hydrogen exports are a key demand component outlined in the NHS, the IAE deems it likely that Ireland will import hydrogen in the future. Firstly, Ireland's renewable electricity generation is a lot less stable and predictable, which makes hydrogen production more difficult. Second, Ireland's pre-tax electricity prices are among the highest in Europe, placing Ireland at an immediate cost disadvantage. Third, Ireland is less likely to have centres of demand in industry and transport at the same scale as other countries, making it more likely that imports will be cheaper than domestic production.[93] A strong priority would need to be given to energy security in order to justify state support for more expensive production in Ireland.

[89] https://www.irvingoil.com/en-US/press-room/irving-oil-and-simply-blue-group-announce-plans-explore-renewable-energy-hub-cork
[90] IAE (2023) A commentary on the medium term prospects of Ireland's hydrogen economy. Available here 91 GNI (2022) Injecting green hydrogen blends into Ireland's gas network. Available here.
[92] European Council (2023) Gas package: member states set their position on future gas and hydrogen market. Available here
[93] IAE (2023) A commentary on the medium term prospects of Ireland's hydrogen economy. Available here

Figure 19: Projected hydrogen demand in 2050



Source: *Government of Ireland (2023) National Hydrogen Strategy. Available here*

Hydrogen production

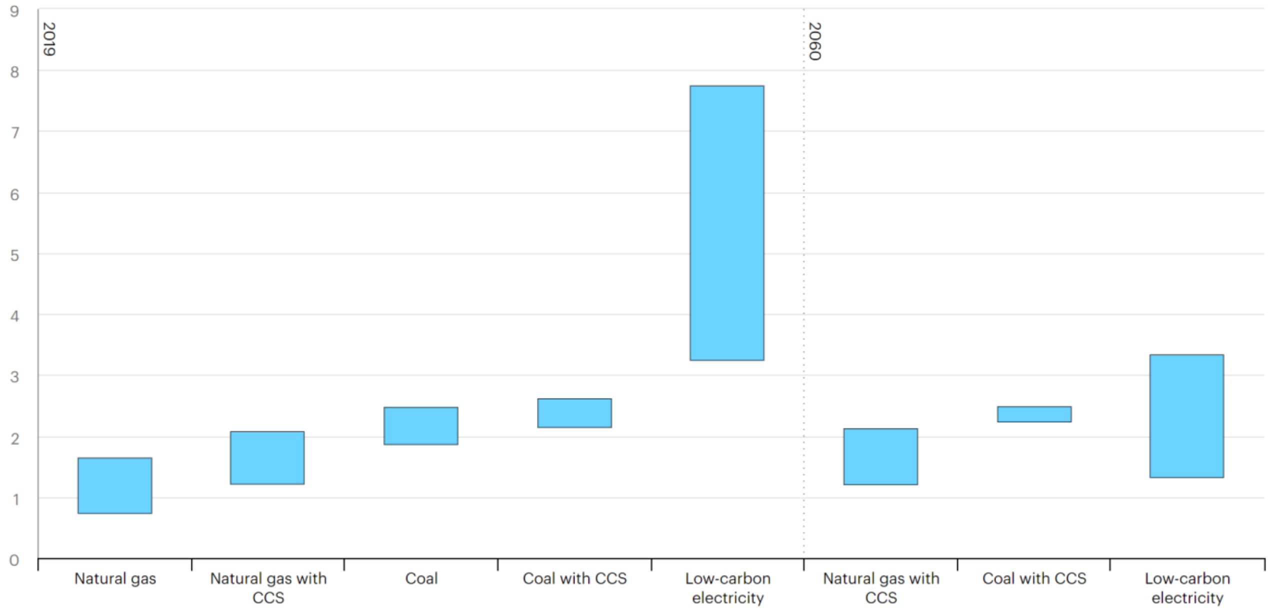
Hydrogen production is a vital input into hydrogen-fired power generation. Assuming the use of electrolysers, the two most significant cost components of hydrogen are the price of renewable electricity and the capital costs of electrolysers. It is also possible to supply power to electrolysers from the electricity grid.

However, the costs of hydrogen production are uncertain. The Hydrogen Council predicts that the costs of renewable hydrogen could fall as low as 2.5c–4.5c/kWh (or €0.82-1.46/kg) by 2050. However, the lowest estimate by the European Hydrogen Observatory of LCOH is much higher, at €3.41/kg and Aurora research calculates a LCOH of €3.50/kg in 2030 under optimal conditions.[94]

The cost of producing hydrogen varies not just across assumptions of electrolyser technology and grid connection, but also fuel type. *Figure 20* shows the current levelised cost range estimates of hydrogen using natural gas and coal (with and without CCS), versus low carbon electricity.

[94] A 100 MW electrolyser connected to 150 MW of onshore wind and 20 MW solar generation, not connected to the transmission system, located in Connaught. Available here

Figure 20: Low and high LCOH estimates, $/kg



Source: *IEA (2020) Global average levelised cost of hydrogen production by energy source and technology, 2019 and 2015. Available here*

It is possible to supply power to electrolysers via the electricity grid. However, this raises further questions as to the true carbon impact of producing hydrogen, especially in the context of the conversion losses and energy requirements discussed within this report. Although this issue should become less relevant as the share of renewables in electricity generation increases to meet the 2030 targets, the EU has established rules determining whether hydrogen from grid electrolysis is considered renewable.[95] The rules specify that green hydrogen must be produced within an electricity system where renewable energy exceeds 90% of total generation over a calendar year, or during periods of curtailment or dispatch down. However, significant regulatory work is still needed at the European level to establish guarantees of origin for green hydrogen.

The Irish National Hydrogen Strategy models the costs and benefits of different scenarios under which operating grid electrolysis is permitted. Benefits are expected to be positive if electrolysers are run during times of high wind to reduce curtailment, or where electrolysers operate at 50% of full load to deliver balancing and operating reserve system services. Counteracting these benefits are the opportunity costs that arise whereby electrolysers compete against other storage assets for excess RES.

At the core of each scenario outlined in the NHS is the goal of reducing the levelised cost of hydrogen (LCOH) by maximising the utilisation of electrolysers. This approach must be balanced with considerations of efficiency losses and the potential additional strain electrolysers could place on the electricity grid.
It is reasonable to assume that a certain level of grid electrolysis is necessary as it is unlikely that electrolyser demand will be fully satisfied by off-grid capacity alone. Given the high degree of uncertainty around the future of electrolysis, EirGrid does not include it in its modelling of Total Electricity Requirement. It is unclear what share of the extra load that electrolysers may provide will be supplied by non-grid connected generators.

[95] European Commission (2022) Production of renewable transport fuels – share of renewable electricity (requirements) – Commission adoption Article 4.1. Available here

Power generation - Projections of LCOE from H2 plant

Most existing gas turbines can handle hydrogen shares of 3–5%, with even fewer capable of operating under varying blends. Research into the development of pure hydrogen power turbines is still ongoing, and EU Turbines (the association of gas and steam turbine manufacturers) are confident that turbines will soon be able to run entirely on hydrogen, with promising signs from Mitsubishi that they could develop such turbines by 2025.[96]

The role of hydrogen for power generation is still uncertain, given that this use is still a nascent technology. As such, uncertainty exists on the costs of generation using hydrogen and indeed on the cost of hydrogen production itself. *Table 6* presents the main cost assumptions for 100% hydrogen-fired CCGTs in the UK, as estimated by DESNZ. These estimates do not yet include retrofitted hydrogen turbines.

Table 6: Main cost assumptions for 100% hydrogen-fired CCGTs

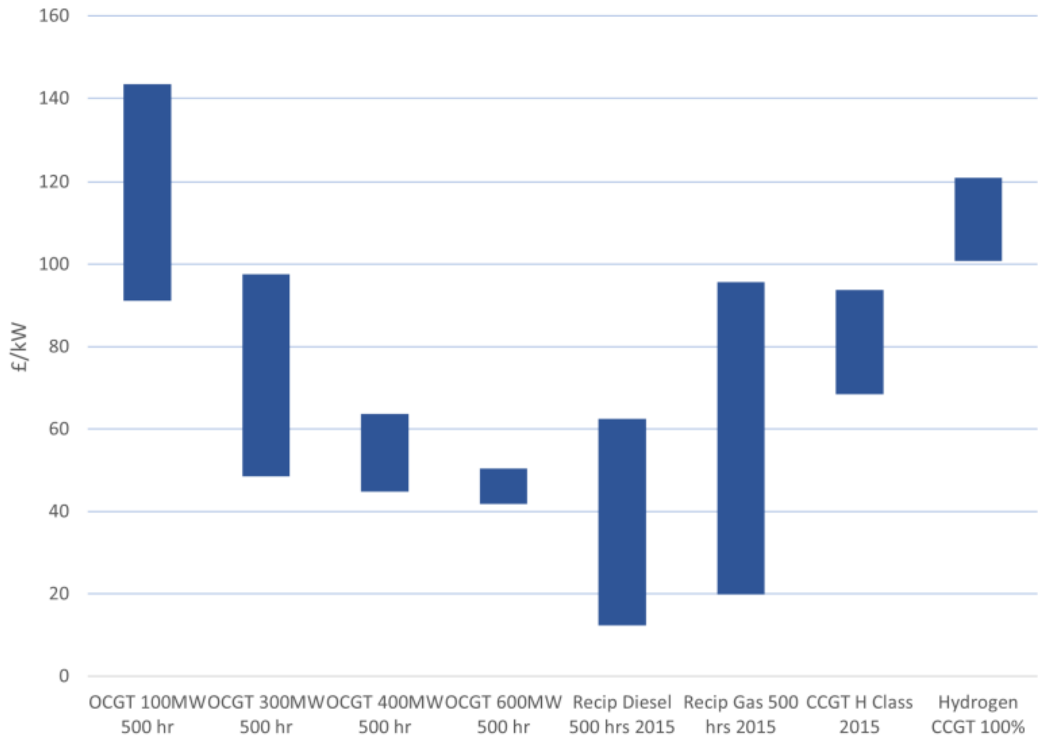
Cost item	2025	2030	2035	2040
Total pre-development (£m)	20	20	20	20
Total construction (£m)	830	830	830	740
Fixed O&M (£/MW/year)	15,500	15,500	15,500	14,000
Variable O&M (£/MWh)	2	2	2	2
Load factor (net of availability)	93%	93%	93%	93%
Operating period	25	25	25	25

Source: DESNZ : Electricity Generation Costs 2023 available here

DESNZ also produces LCOE for various peaking technologies that enable a comparison on a £/Kw basis. *Figure 21* below shows the peaking technologies of reciprocating diesel and gas, OCGT and Hydrogen CCGT 1 GW, assumed to run 500 hours per year, and unabated gas CCGT at normal load factors, all assumed to be commissioned in 2025. Little detail is available on how those hydrogen CCGT costs may decline over time. A hydrogen-fuelled CCGT of this capacity might burn the equivalent of 1.15 TWh of hydrogen over 500 hours of operation.[97] Producing this quantity of hydrogen from renewables in Ireland and storing it would arguably not be feasible for a CCGT turbine of this size. Some argue that much smaller turbines (200 MW) would be needed to calibrate to renewables generation and storage at meaningful scale.[98] The IAE makes an initial estimate that with current technology back-up electricity produced using green hydrogen could cost between €377 and €516 per MWh in Ireland. That is, using the average accepted bid price of €86 per MWh on the Irish Offshore-RESS auction with Proton Exchange Membrane technology for electrolysis.[99]

[96] Nature (2024) Turbines driven purely by hydrogen in the pipeline. Available here
[97] Based on the assumption of a gas turbine with a capacity of 575 MW burning 40 tonnes per hour of H2 and an assumption of 1kg of H2 with an energy value of about 33.3 kWh. Source – Turbo Machinery International : https://www.turbomachinerymag.com/view/hydrogen-turbines
[98] Gulen, Zachary (2022) Feasibility of Achieving 62% Combined Cycle Efficiency With a 200 MW Gas Turbine. Available here.
[99] IAE (2023) A commentary on the medium term prospects of Ireland's hydrogen economy. Available here

Figure 21: Peaking technologies annual costs



Source: DESNZ Electricity generation costs 2023

Note: £/kW per annum presented for construction and fixed operating costs, with technology-specific discount rates. 2025 commissioning dates

Hydrogen converted to ammonia for power generation

Hydrogen has a share of less than 0.2% in the global electricity generation mix, and most of this share is in the form of ammonia converted from hydrogen.[100] Synthetic fuels (such as ammonia) produced using hydrogen possess technical qualities that make them more suitable to various end-use applications such as aviation and industry. Co-firing of ammonia in coal-fired power plants is still at demonstration stage and has been demonstrated in trials in Japan and China. Furthermore, the direct use of 100% ammonia was successfully demonstrated in a 2 MW gas turbine at IHI Yokohama works in Japan.

Although converting hydrogen to ammonia and shipping it as fuel is technically feasible, it has not been attempted at a large scale. Given that the transport and storage technology of ammonia have already been proven, ammonia is the most likely solution in Ireland capable of achieving high flow rates of hydrogen. Its liquification temperature is -33 degrees Celsius and has the potential to be stored in offshore LNG facilities. It has other problems due to its toxicity, which led it to be withdrawn from some end-use applications such as refrigeration systems. [101]

Transport and storage

The NHS outlines transport alternatives for hydrogen in Ireland. These include:

- compressed tankers: well-suited to decentralised small-scale applications, with their relatively low capital cost compared to pipelines, making them an attractive option for small hydrogen volumes;

[100] IEA – Global Hydrogen Review, 2023

[101] IAE (2023) A commentary on the medium term prospects of Ireland's hydrogen economy. Available here

- Pipelines: would allow the highest volume, lowest cost in the long term, but lacking a regulatory framework, which is risky for investors; and
- synthetic carriers: in the form of ammonia, e-methanol and e-kerosene represent an alternative to hydrogen liquefication and are suitable to aviation and to shipping, unlike gaseous hydrogen.

Hydrogen storage will help to balance fluctuations in supply from variable renewable generation and seasonal changes in demand in the same way as gas at present. The most viable options for hydrogen storage are:

- compressed tankers: a suitable option for decentralised small-scale applications, offering quick and flexible deployment;[102]
- line packs: of limited use except in emergency situations given hydrogen's low density[103];
- geological storage solutions in salt caverns or depleted oil and gas fields: a potential long-term option given the potential number of caverns and the relatively low cost; and
- hydrogen derived carrier storage: once converted to a synthetic fuel but suffers from substantial conversion loss and is less economically viable.

Considering geological storage options requires balancing several factors including density, capacity, discharge time, leakage, chemical reactions, and seismic risks.[104] Salt caverns are considered a suitable option for initial development as they have the shortest response times and lowest risk of losses from chemical reactions and leakage. Depleted gas fields are a potential option for scaling up storage as they have an abundance of available data for subsurface characterisation; existing infrastructure could be repurposed to convert a production site into a storage facility.

In Ireland, salt deposits tend to be restricted to offshore Permian and Triassic sedimentary basins along the east, south and north-west coasts, where existing borehole and seismic data can facilitate the future characterisation of these salt deposits for potential geological storage of hydrogen. A recent study identified 6,000 potential caverns in the two sea basins, which are located at the optimum depth and thickness for hydrogen storage. Assuming 1% of these were viable storage options, these could deliver 60 TWh of cumulative hydrogen storage, which would be enough to meet the indicative 90-day hydrogen storage needs for 2050 demand estimates in Ireland. [105]

There are no subsurface basins with halite salt onshore in the Republic, although one exists in Northern Ireland: Islandmagee. The Islandmagee project is currently in early-stage construction and aims to develop seven underground caverns capable of storing up to 500 mcm of natural gas in Permian salt beds. The salt caverns are at a depth of approximately 1400m below Larne Lough. It is estimated that it will have a withdrawal capability of 22m cubic meters of gas per day for 14 days,[106] which could create around 0.21 TWh of useable energy per day.[107]

In the Republic of Ireland, one example of the potential for depleted gas field storage is the Kestrel Project. ESB, dCarbonX and Bord Gáis Energy are proposing to redevelop the decommissioned gas reservoirs in the

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[102] Volume depends on tank type and pressure capabilities. A typical hydrogen car tank capacity is around 4-6kg of hydrogen weighing around 100kg (see Hyfindr (2023) Hydrogen Tank I – IV. Available here).
[103] As a comparison, Ireland's natural gas pipelines transported just under 60,000 GWh of natural gas in 2019 (see GN~~I (20~~20) Systems Performance, Available here)
[104] English and English (2022) Overview of hydrogen and geo-storage potential in Ireland. Available here
[105] SLR (2024) Hydrogen Salt Storage Assessment (HYSS). Available here
[106] Islandmagee Storage (2020) Environmental Statement Non-technical Summary. Available here
[107] SEAI conversion factors, available here

offshore Kinsale area for large-scale hydrogen storage. ESB and BGE operate significant electrical generation capacity at their nearby onshore Aghada and Whitegate gas-fired power stations. English and English estimate the total energy storage capacity for the Kinsale Head and Corrib gas fields at circa 134 TWh and 75 TWh respectively, of which half is working gas capacity of 67 TWh and 38 TWh respectively assuming a cushion gas requirement of 50%.[108] The Irish Academy of Engineering (IAE) estimates the scale of investment required to produce the "cushion gas" to restore the pressures required for high volume delivery to be many multiples the price paid for the natural gas produced from those fields.

The volume of required storage for electricity generation will depend on assumptions on running profiles of plants.[109] Recovering the hydrogen from geological storage at flow rates required for electricity generation presents a further challenge. The IAE estimates that 4 GW of hydrogen back-up dispatchable power generation would require 18 times the peak flow rate from the SW Kinsale reservoir when it was used to store natural gas, and 6.6 times the peak flow rate from the Corrib Field (in 2017).

Regulatory and legislative planning issues

Regulation is required across multiple stages of the hydrogen supply chain, including production, transport, storage and end use. Due to its relative infancy as an industry, the current regulation is inadequate to facilitate the safe and efficient scaling up of hydrogen.

There is no specific occupational health and safety legislation at the European or national level specific to hydrogen. The current regulatory regime for natural gas implemented by the CRU does cover the safety of blends of hydrogen of up to 20%, however future legislation will be needed for pure hydrogen transport.[110] While the HSA regulates the transport and storage of dangerous goods, requirements under COMAH legislation are only relevant where the maximum anticipated quantity of hydrogen is greater than five tonnes. This will have implications for potential end users such as hydrogen refuelling stations, which will fall under this threshold. COMAH would also cover large scale storage of ammonia due to its poisonous nature. Storage of ammonia would require significant sterilisation zones around the chosen site.

The EU is currently developing the Hydrogen and Decarbonised Gas Market Package with the aim of developing a framework, which enables the deployment of renewable gas and establishes rules on hydrogen infrastructure development. Most rules proposed align with the regulatory regime that underpins today's integrated natural gas market in Europe.[111]

International examples of hydrogen power generation and production

Most projects for hydrogen powered electricity generation are currently under development.

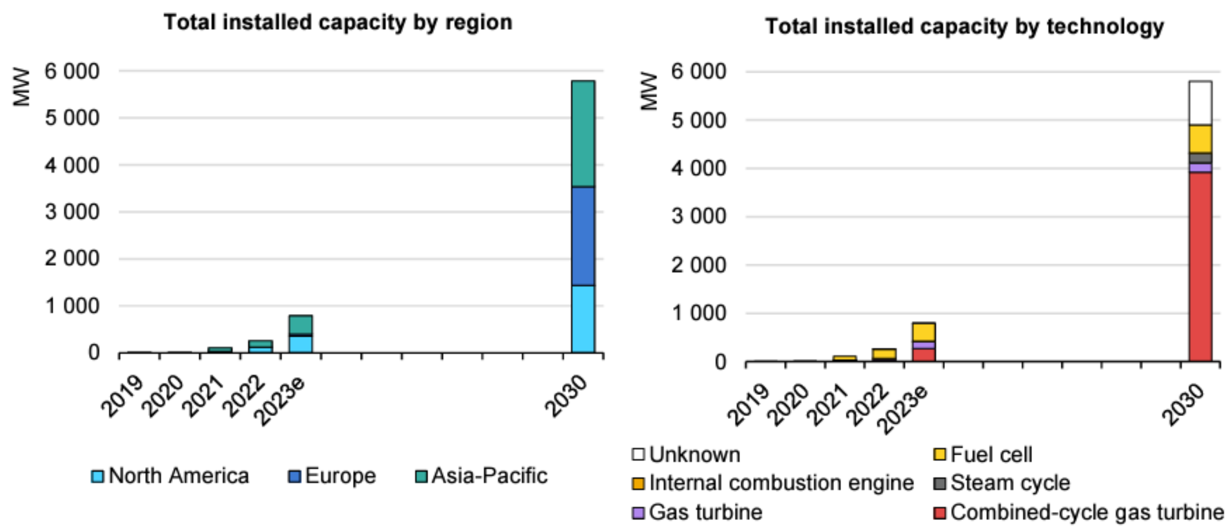
- Several utilities in North America, Europe and the Asia-Pacific region are exploring the possibility to co-fire hydrogen with natural gas in combined-cycle or open-cycle gas turbines. For example, the Saltend

[108] English and English (2022) Overview of Hydrogen and Geostorage Potential in Ireland. Available here
[109] For instance, if we assume a 60 Hz J+ class turbine of 300 MW burns circa 30 tonnes of hydrogen per hour and running for 500 hours per year, this would result in around 0.345 TWh equivalent of hydrogen. Assuming a hydrogen energy value conversion factor of 33.3 kWh per kg/H2a PEM electrolyser requires around 55 kWh per kg of hydrogen, thus requiring 2.2 GW of green power. However, the total dispatch down of wind energy in Ireland was only 988 GWh in 2022. More information at Carbon commentary (2021) Some rules of thumb for the hydrogen economy. Available here. Turbomachinery international (2023) Hydrogen turbines. Available here.
[110] Gas Networks Ireland, Hydrogen and Ireland's national gas network. Available here
[111] Government of Ireland (2023) National Hydrogen strategy. Available here

project aims to refurbish 1,200 MW natural gas-fired combined heat and power plant for 30% hydrogen co-firing share by 2027.[112]

- Other demonstration projects have been announced that focus on increasing their hydrogen co-firing share, including Hanwha Impact in Korea, a 15% hydrogen co-firing share gas turbine in Austria tested by Wienenergy and commercial partners including Siemens, and a 38% hydrogen co-firing share achieved by Constellation's Hillabee Generating Station.
- In Asia, several projects have been announced to explore the use of ammonia in coal-fired power plants.[113]

Figure 22: Power generation capacity using hydrogen and ammonia by region, historical and announced projects, 2019-2030



Source: IEA (2023) Global hydrogen review 2023. Available here

Around 70% of projects are linked to hydrogen use in open-cycle or combined-cycle gas turbines, while the use of hydrogen in fuel cells accounts for 10% and the co-firing of ammonia in coal-fired power plants for 3% of the capacity of announced projects. Regionally, these projects are principally located in the Asia-Pacific region (39%), Europe (36%) and North America (25%) (*Figure 22*).

In addition, several utilities announced plans to build new gas power plants or to upgrade existing gas power plants to be H2-ready, i.e. able to co-fire a share of hydrogen.[114] The hydrogen share of the H2-ready announced capacity would correspond to 3 400 MW. Existing gas-fired power plants can handle from 10% to 100% hydrogen, depending on the gas turbine design. The hydrogen-fired capacity from existing gas turbines could amount to more than 70 GW globally.[115]

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[112] Hydrogen shares are on a volumetric basis.
[113] IEA – Global Hydrogen Review, 2023
[114] There is disagreement on what exactly it means to be hydrogen-ready. For instance, EU Turbines identifies different readiness categories for a given share of hydrogen between 10% - 100%, depending on technical adaptions and related investments required (see EU Turbines (2024) H2-Ready Definition. Available here). The Siemens definition is much narrower, and refers to plants that are prepared for immediate conversion to 100% hydrogen (see Siemens Energy (2022) Ten fundamentals to hydrogen readiness. Available here). For the purposes of our discussion, we are referring to plants that can co-fire a share of hydrogen.
[115] IEA – Global Hydrogen Review, 2023. Available here

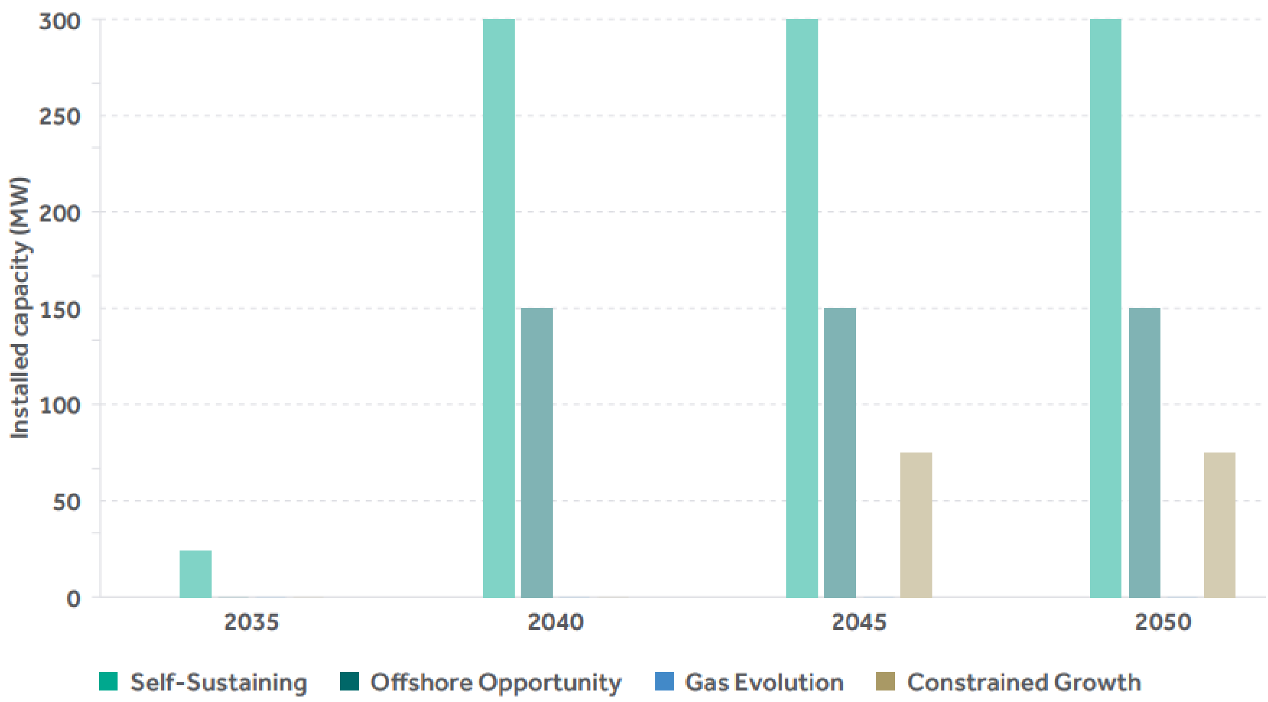
15. Carbon capture and storage from gas and bio-energy plant

In this section we summarise the drivers of deployment of CCS in the Irish power sector (on gas and bioenergy plant). These include advances in CCS in other jurisdictions, LCOE for CCS power generation, technical barriers to CCS uptake, and CCS potential in the Irish context.

Currently, CCS is not a commercially viable technology in Ireland and the speed of its development in the future is uncertain. However, policy and long-term scenario planning envisage a significant role for CCS in decarbonising the Irish energy sector. This is envisaged to include retrofitting existing power plants, and waste-to-energy facilities with carbon capture capabilities, as well as building out necessary transport and storage infrastructure.[116]

The presence of negative emission technologies such as Bio-Energy with CCS (BECCS) can be important in a future power system as it allows some unabated power generation to run while the system overall achieves zero net emissions. When constrained to meet ambitious net zero targets in the power sector, EirGrid's scenarios indicate a preference for BECCS over biomass by 2040. EirGrid's most recent modelling assumes that biomass with CCS will become available between 2033 and 2045 forming a significant part of a least-cost generation mix by 2040 for one out of four scenarios (*Figure 23*).[117] High-level scenarios from SEAI also indicate the negative emissions contributions of several potential gas-CCS (up to five sites) and BECCS generation sites in Ireland (*Figure 24*).

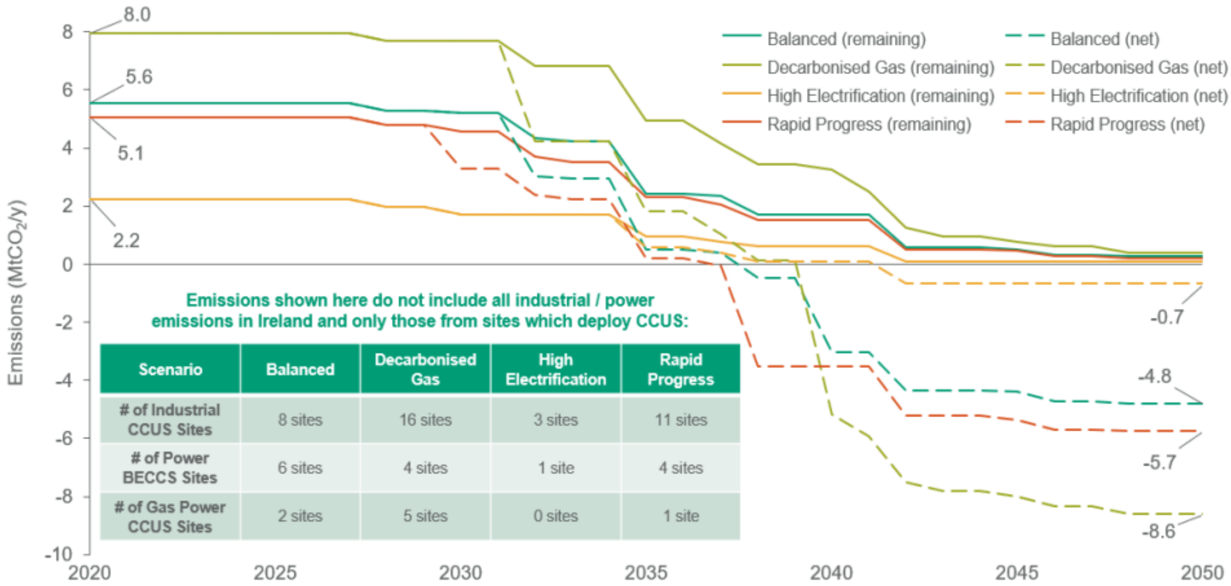
Figure 23: Biomass and BECCs capacity under different long-term power sector decarbonisation scenarios



Source: EirGrid Tomorrow's Energy Scenarios 2023 Consultation Report

[116] Government of Ireland (2023) Climate Action Plan 2024. Available here
[117] EirGrid Tomorrow's Energy Scenarios 2023 Consultation Report

Figure 24: Remaining and net emissions from all industrial and power sites abated by CCUS or BECCS



Scenario	Balanced	Decarbonised Gas	High Electrification	Rapid Progress
# of Industrial CCUS Sites	8 sites	16 sites	3 sites	11 sites
# of Power BECCS Sites	6 sites	4 sites	1 site	4 sites
# of Gas Power CCUS Sites	2 sites	5 sites	0 sites	1 site

Source: SEAI (2022) Carbon Capture Utilisation and Storage (CCUS). Available here

Other jurisdictions with CCS power generation and storage

The future availability and deployment rate of CCS in the Irish power sector is highly dependent on the outcome of RD&D activities in other jurisdictions, including the performance of pilot and demonstration projects elsewhere in the world. Internationally, the CCS industry is at an early stage, although it is developing rapidly. Approximately 40 commercial facilities are in operation applying CCS processes with a further 500 projects in development.[118] CCS projects are now operating or under development in 25 countries around the world, with the United States and Europe (UK, Norway, Netherlands) [119] accounting for three-quarters of the projects in development[120]. Other countries such as Australia and Canada have also been described as first movers.[121] Some of these are described in *Table 7* below.

Support for CCUS is also growing in Canada and Australia. Canada has announced an investment tax credit for CCUS and CAD 319 million in funding to support CCUS RD&D. In Australia, AUD 250 million in funding has been announced for CCUS hubs alongside the inclusion of CCUS under the Emissions Reduction Fund valued at around AUD 20/tCO2).

Projections of LCOEs for plants with CCS

Cost reductions are a challenge and are crucial for the wide-scale deployment of CCS.[122] The UK's Department for Business, Energy and Industrial Strategy outlines the predicted LCOE across multiple fuel types and scenarios in its Electricity Generation Costs 2020 report. [123] Figure 25 presents the levelised cost estimates for CCGT + CCS Post Combustion and Biomass CCS projects commissioned in 2025, 2030 and 2040. The cost of biomass projects is expected to be more than double that of CCGT across all years, despite having a greater reduction in total real costs by 2040.

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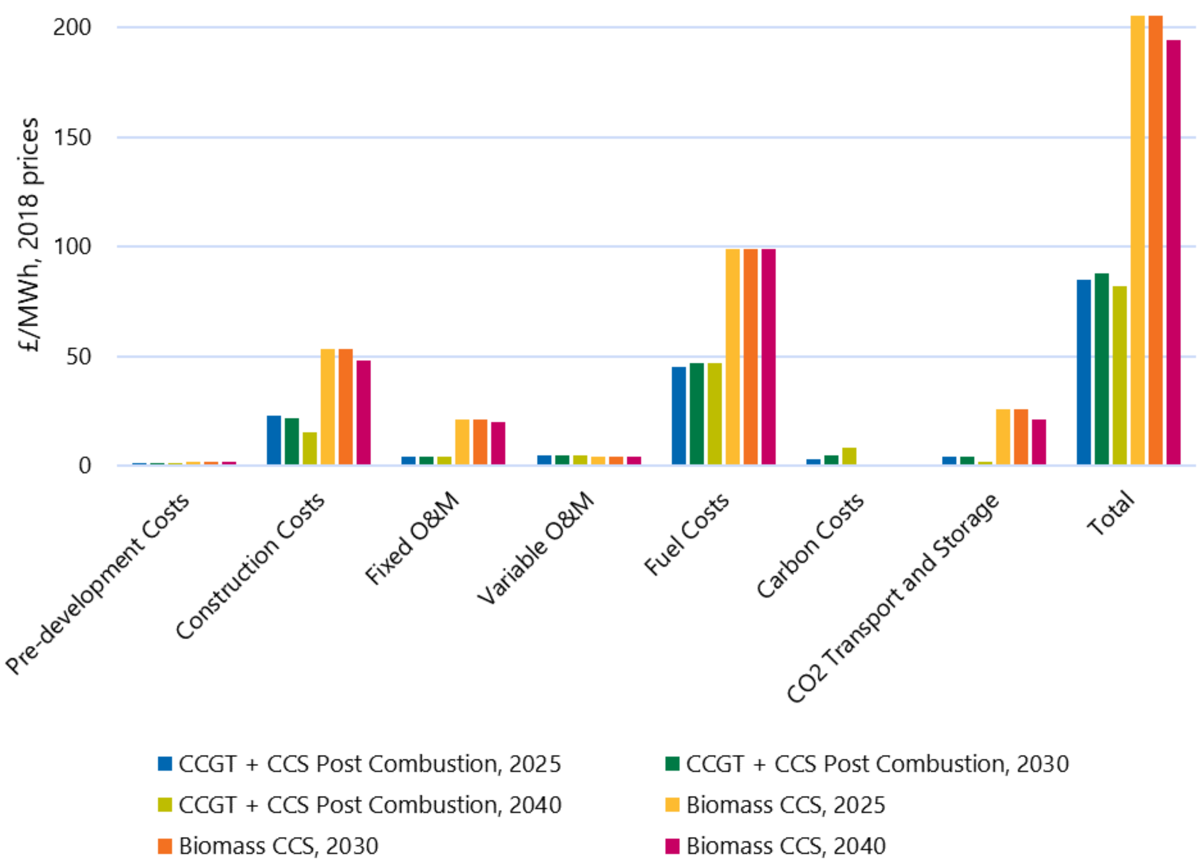
[118] IEA https://www.iea.org/energy-system/carbon-capture-utilisation-and-storage
[119] IEA (2021) Carbon capture in 2021 : Off and running or another false start? Available here
[120] IEA (2021) Carbon capture in 2021 : Off and running or another false start? Available here
[121] Energy Focus (2023) Five countries leading the way in carbon capture and storage. Available here
[122] Diego et al, "Making gas-CCS a commercial reality: The challenges of scaling up (2017). Available here
[123] The updated 2023 report from DESNZ does not update its cost estimates for power generation with CCUS

Table 7: Overview of CCS projects in development

Country	Project name	Investment	Target capture
Norway	Northern Lights offshore storage hub	1.8 bn USD	1.5 Mt pa from 2024
Netherlands	Porthos CCUS hub	2 bn EUR (max)	
UK	Net Zero Teeside – full chain CCS[48]	1 bn GBP	4 Mt pa from 2027
UK	Drax – BECCs pilot[49] - part of proposed Zero Carbon Humber CCUS hub	31.7 bn GBP[124]	1.3 tonne/day from 2027
USA	Houston Ship Channel CCS	100 bn USD	100 Mtpa by 2040
USA	Direct Air Capture – Permian Basin	1.3 bn USD	0.5 – 1.0Mt pa in 2024
USA	Next Decade[125] - CCS in LNG supply chain	18.4 bn USD	Up to 5 m Mt
Japan	Tomakomai CCS Demo project (2016–19)	300m USD[126]	0.1 Mtpa – 0.3 Mtpa

Source – Frontier Economics

Figure 25: Levelised cost estimates for projects commissioning in 2025, 2030 and 2040



Source: Department for Business, Energy and Industrial Strategy (2020) Electricity generation costs 2020. Available here.

[124] Ember (2021) Understanding the cost of the Drax BECCS plant to UK consumers. Available here 125 https://nextdecade.gcs-web.com/static-files/03effa09-1b7f-4245-95a9-cc88d74f75e4
[126] Reuters (2018) Available here

Technical barriers to CCS power generation deployment

There are some key risks and uncertainties for CCS development, including site performance risks (effective capacity and injectivity); containment risks (effective CO2 containment in the storage phase); public perception risks; and market failure risks (relating to the expected revenue stream and demand).

Post-combustion technology is the most mature technology option for CCS from CCGT plant, with the option to integrate the provision of necessary steam from the main CCGT plant or to build separate auxiliary boilers with electricity supplied from the grid connection.[127] Site-specific space constraints may pose a significant challenge to the integration of a new capture plant with an existing power plant. Furthermore, the addition of a capture plant to a CCGT plant is typically estimated to incur an efficiency penalty of around eight percentage points.

SEAI has identified infrastructure development[128] as a key constraint for adopting CCUS at both industrial and power sites, and particularly for more dispersed sites. The development of onshore transport options is unlikely to be a limiting factor for the deployment of CCUS in Ireland. While obtaining permits for onshore pipelines can be a lengthy process, trailers can be procured within relatively short timeframes—typically less than four years. Rather, the technology readiness of carbon capture and the availability of downstream transport and storage infrastructure at a site will be the key constraints for adoption of CCUS abatement. Previous studies have estimated lead times for CO2 shipping infrastructure to be around five to seven years.[129]

The spatial distribution of the source emitters is also an important consideration as the more closely clustered the sites are, the lower the overall cost of the CO2 transportation and shipping. Large point carbon source emitters would need reassurance about the viable downstream CO2 transport and storage options before investing in CO2 capture. Potential storage sites in Ireland are discussed further below.

Legal and regulatory issues

The Climate Action Plan 2024 sets an action to develop a clear framework to assist long-term decisions on CCS. The EU Directive 2009/31/EC on Geological Storage of CO2 requires that EU Member States ensure that all operators of combustion plants of 300 MW or more demonstrate that suitable storage sites are available, and transport facilities and retrofit for CO2 capture are technically and economically feasible. This minimum size of 300MW also corresponds to examples in Australia and the UK.[130] [131]

In relation to Irish legislation, the capture element of a CCS project could largely be regulated under existing planning and environmental law.[132] In relation to storage, the following two Statutory Instruments (S.I.) transpose Directive 2009/31/EC into Irish legislation. These are currently the only two Irish regulations specifically relating to carbon capture and storage.

- European Communities (Geological Storage of Carbon Dioxide) Regulations, S.I. No. 575 of 2011.125.
- European Communities (Geological Storage of Carbon Dioxide) (Amendment) Regulations, S.I. No. 279 of 2014.126.

[127] Poppa et al in Energy Procedia 4, "Carbon Capture Considerations for Combined Cycle Gas Turbine" (2011)
[128] SEAI (2022) Carbon Capture Utilisation and Storage (CCUS). Available here
[129] Ibid, cited from Element Energy, 'Deep Decarbonisation Pathways for UK Industry', pg. 80. A report for the Climate Change Committee, November 2020. Available here
[130] Aurecon (2022) Costs and Technical Parameter Review. Available here
[131] Poppa et al in Energy Procedia 4, "Carbon Capture Considerations for Combined Cycle Gas Turbine"
[132] Ervia (2020) Carbon Capture and Storage for Ireland: Initial Assessment. Available here

Through these regulations, Ireland is one of several countries that have applied restrictions on CO_2 storage. Article 4 of the S.I. No. 575 of 2011, Selection of Storage Sites, prohibits storage of CO_2 in amounts greater than 100,000 tonnes. However, the explanatory note accompanying S.I. No. 575 of 2011 recognises the potential value of CCS and states that the restriction will be kept under active review. For a CCS project in Ireland to progress, the regulation would need to be amended or revoked, and the full permitting requirements of the CCS Directive would need to be transposed into Irish law. Ultimately this would require a framework of consents for the storage of CO_2 in Ireland to be developed and implemented.

There is no specific legislation or consenting regime in place to regulate the construction or operation of a pipeline transporting CO_2 in Ireland. A regime similar to that currently in place for gas pipelines under the Gas Act (1976)127, as amended, could be introduced for CO_2 pipelines.

Bio-energy supply chains in Ireland and potential constraints on BECCS

BECCS involves the combination of bioenergy production with CCS. There are several potential supply chain problems that could affect BECCS implementation, including biomass availability, land use and competition, sufficiently large storage and transport, and transportation infrastructure as discussed above.

There are currently some indicative pathways for the deployment of negative emissions technologies in Ireland.[133] In the short to medium term (five to fifteen years), the most promising option appears to be afforestation, owing to its simplicity and technical maturity. Afforestation can be a short-term CO_2 removal triage measure with a clear strategic objective for the removed carbon to be transferred to secure, long-term geological storage as soon as possible, most probably through early deployment of BECCS. In the longer term, BECCS (combined with indigenous bioenergy crop cultivation) appear to offer the best prospect of large-scale indigenous CO_2 removal providing a technical potential of 400–600 $MtCO_2$ by 2100. However, the technical potential is premised on extremely ambitious, early, rapid, and sustained deployment of BECCS infrastructure (including CO_2 geo-storage), rapid and sustained land use change to bioenergy cultivation and, ultimately, large-scale land use reallocation. A more conservative estimate would be less than 200$MtCO_2$.

Transport and storage of CO2 in Ireland

Ireland has limited accessible domestic CO_2 storage sites. Moreover, these CO_2 storage sites are also possible hydrogen storage sites, as described in the section above. The greatest potential exists offshore in saline aquifers but the most accessible storage is in the depleted gas fields of Kinsale Head and Corrib gas field. Islandmagee in Northern Ireland is a secondary potential site.

[133] McMullin et al, (2020) IE-NETs: Investigating the Potential for Negative Emissions Technologies (NETs) in Ireland, EPA research paper. Available here

Table 8: Principal gas storage sites

Gas field	Capacity (CO2)	Comment
Kinsale	321 Mt	Decommissioned gas site, potential option for carbon or H2
Corrib	44 Mt[134]	Gas site, in operation for the next 10-15 years.
Islandmagee	500 mcm – gas capacity[135]	A salt gas storage project. Development timeline is unclear

Kinsale gas field has been identified as an attractive target for CCS because the overall capacity and injectivity appear to be satisfactory, but its potential remains to be proven for large scale CCS. It has a carbon storage capacity of 321 Mt, the equivalent of up to 40 years of CO2 emissions from the top 10 point-source emitters in Ireland.[136]

Kinsale gas field could receive carbon from power plants and industry in the Cork area. 1.5 to 2.5 Mt of CO2 per annum could be captured this way (i.e. up to a quarter of Irish annual gas related emissions). [137] SEAI cited an estimate of €12/tCO2 storage cost for Kinsale.[138] The offshore pipeline required from Cork could cost an estimated additional €2/tCO2. In comparison, the Northern Lights Project, a Norwegian CCS project with a targeted scale of 5 Mt pa CO2 captured by 2030, has a targeted combined cost range of €30-55/tCO2 for transport and storage by 2030.[139]

[134] English and English (2022) Carbon capture and storage potential in Ireland – returning carbon whence it came
[135] Islandmagee Energy (2024) Islandmagee gas storage project. Available here
[136] English and English (2022) Carbon capture and storage potential in Ireland – returning carbon whence it came
[137] Ervia (2020) Carbon Capture and Storage for Ireland: Initial Assessment. Available here. Ervia (2022) has commissioned a pre-FEED study to evaluate the infrastructure necessary for the compressing and transport of liquid CO2 at Cork harbour for subsequent export to the Northern Lights project, here.
[138] SEAI. CCUS 'Suitability, Costs and Deployment Options in Ireland', available here
[139] Smith et al, The cost of CO2 transport and storage in global integrated assessment modelling, International Journal of Greenhouse Gas, vol 109, July 2021

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