WIND ENERGY IRELAND

Baringa

Bridging the Gap

Towards a zero-carbon power grid

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tnei

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Foreword from Wind Energy Ireland

It doesn’t feel like an emergency.

Just over three years ago the Oireachtas voted unanimously to declare that Ireland was in the middle of a climate and biodiversity emergency.

During the debate speaker after speaker warned of the growing threat posed to our country and our way of life from climate change. And many took the opportunity to remind their colleagues that declaring an emergency means absolutely nothing if there is no action to back it up.

It would be wrong to deny there has been progress. New renewable energy projects are under development, a planning framework for offshore wind energy is in place, solar power has started to connect to the grid for the first time.

But, as *Bridging the Gap* shows clearly, it is too little, and it may soon be too late.

The simple reality is that we are not moving fast enough.

Ireland is failing to plan properly and, as a result, is planning to fail. Our existing strategies and plans and targets are not adequate.

Unless our government, and wider society, understands this and is willing to respond, to act, then this report makes clear that we cannot achieve the carbon emissions reductions which will be required of the electricity sector.

Fixing this is possible but it requires us first to be honest about the scale of the problem. This is not about fixing a planning regulation or making some minor amendments in how we expand our grid capacity.

Hitting our 2030 targets, cutting our carbon emissions by 51%, is still – just about – possible but if it is to be done it must become a national mission, driven from the very highest levels of government but reaching into every community and home right across Ireland.

The full resources of the State must be brought to bear with determination and constancy. We must recognise the threat we face from climate change is far greater than the one we faced from Covid, and we must respond accordingly.

And it has never been more urgent to do so. Russia’s brutal invasion of Ukraine has seen spiralling gas and electricity prices across Europe. This means real hardship for families who will struggle to pay bills that, ultimately, end up funding Russia’s war in Ukraine.

Ireland can play a critical role in defending Europe. Not with guns or tanks, but with wind turbines and solar panels.

As Fintan O’Toole wrote recently:

“It is now obvious that the great European economic project of the next decade will be independence in the production of energy. Ireland can be right at the forefront of a new industrial revolution. And, in doing so, it can genuinely enhance the safety and security of Europe by becoming a significant exporter to the continent of clean and renewable energy.”

We can replace natural gas from Russia with green hydrogen from Cork and electricity generated in Donegal.

As this report shows the task before us – very broadly – breaks down into two key questions.

First, what can we do to build more wind farms – onshore and offshore – more solar farms and more energy storage projects as quickly as possible?

This is about speed. We know what to do. We have the expertise and the skills. We have the investment. We are ready. We are waiting.

But we cannot build these projects if we cannot get them through the planning system, if we cannot navigate the process to connect them to the electricity grid and then must wait for an opportunity, which comes every year or two, to win a contract to be built.

At every single step of this process we are taking too long. Projects languish for years in a planning system that is – fundamentally and utterly – not up to the job. Connecting to the grid is slow and expensive. We need to create more routes to market and to do that we need to make developing renewables cheaper.

Everything needs to change. The entire system of how we develop renewable energy in Ireland, from start to finish, needs to be completely redesigned.

And if we can achieve all of that, we will still fail, because we also need to answer the second key question.

How can we build an electricity grid in Ireland that will provide a secure supply of clean energy to every household and business on the island?

Again, we must start with honesty. Our electricity grid is not fit for purpose. It is a grid designed for a fossil fuel economy in the late 20th century. The outcome of tinkering at the edges or trying to do the minimum is inseparable from intentional failure. Telling ourselves otherwise is delusion.

We need to build critically needed new grid infrastructure like the North-South Interconnector and we must invest in the next stage of EirGrid's DS3 programme to ensure that the system can, when the wind and solar is available, operate with 100 per cent renewables.

Every part of EirGrid's *Shaping Our Electricity Future* strategy needs to be delivered and we need to be honest in being clear that anyone who does not support this strategy is – consciously or otherwise – undermining our country's energy security and our economic future.

But this report from Baringa and TNEI shows that EirGrid's strategy is not enough. It must be built on, integrating new technologies, demand flexibility and zero-carbon solutions. We need more power lines and underground cables to get power from the wind farms and solar farms which will generate it to the homes, farms and businesses that will need it.

We need all of this, and more, because perhaps our greatest need is for leaders and communicators to share this vision with us, to honestly and simply explain to the Irish people the challenges we face and to empower them too to act, to be part of building an energy-independent Ireland at the heart of an energy-secure Europe.

Next year will mark the 60th anniversary of US President John Fitzgerald Kennedy addressing the Dáil. And while he spoke of the threat we faced from nuclear annihilation, his words resonate today as we face a greater danger.

“In an age when a handful of nations have the power literally to devastate mankind, in an age when the needs of the developing nations are so large and staggering that even the richest nations often groan with the burden of assistance— in such an age, it may be asked, how can a nation as small as Ireland play much of a role on the world stage?

“The problems of the world cannot possibly be solved by sceptics. We need those who can dream of things that never were, and ask why not. Great powers have their responsibilities and their burdens, but the smaller nations of the world must fulfil their obligations as well.

“Ireland's hour has come.”

It is now.

Noel Cunniffe

CEO, Wind Energy Ireland

Executive Summary

Ireland's ambition towards power sector decarbonisation to date has been focussed on a vision for 2030. However, the total CO_2 emitted into the atmosphere during this transition to a decarbonised 2030 power sector is dependent upon the Pathway taken, rather than just the end state of the sector. Attention is beginning to shift; as of this year Ireland has adopted a carbon budget, a binding limit on cumulative emissions for the economy as a whole. In this study we have sought to quantify the impact on cumulative power sector emissions brought by the deployment rate of renewables, as well as to test the limit of achievability for the unfolding decade ahead under current policy.

Key findings

- The total **cumulative CO_2 emissions** from the Irish power sector out to 2030 are **sensitive to the Pathway taken to get there**.
- In Pathways that meet Ireland's 2030 targets, our analysis shows that **cumulative power sector emissions can be reduced by 4 million tonnes of CO_2** by the **rapid delivery of renewables** following RESS auctions compared to a delayed delivery of the same capacity.
- In an ambitious Pathway that **exceeds many of Ireland's 2030 targets**, with rapid delivery of renewable capacity and investment in enabling technologies, our analysis shows that **66 million tonnes of CO_2** are emitted from the power sector in the decade **between 2021 and 2030,** including **6 million tonnes resulting from transmission constraints**.
- This Pathway represents a **saving of at least 6 million tonnes of CO_2** compared to a Baseline of EirGrid's ***Shaping our Electricity Future Roadmap***. However, it still substantially exceeds an **indicative sectoral carbon budget of 55 million tonnes of CO_2**.
- Achieving a carbon budget of 66 million tonnes of CO_2 in the power sector requires the build of **onshore wind and solar PV** capacity as **early in the decade as possible** and **proactive investment in enabling technologies**, including:
  - Sources of **system flexibility** to manage **renewable oversupply**, such as interconnection, demand-side response, and energy storage technologies;
  - Provision of **zero-carbon system services** from battery assets and synchronous condensers, to **unwind DS3 limits** and moderate **renewable curtailment**; and
  - The continued **development of the transmission network** including all projects identified in the *Shaping Roadmap*, and further upgrades to circuits throughout Ireland. The rapid deployment of renewables also requires the **strategic deployment of constraint management solutions**, such as dynamic line rating, power flow control, and dedicated energy storage assets, to address **renewable constraint** due to transmission limits.
- Use of **carbon intensive fossil fuels including coal and peat in the first half of the decade** 'locks in' substantial emissions, and puts pressure on carbon budgets. Our analysis suggests that **66 million tonnes of CO_2** between 2021 and 2030 represents the **minimum achievable for the Irish power sector under current policies; major and fast interventions** are required to move the dial past this figure, including solutions to **phase out the usage of these carbon intensive fuels**, and an acceleration of renewables and enabling technologies **above and beyond existing policy**.

Our study

The *Shaping our Electricity Future Roadmap*, published by EirGrid and SONI in November 2021, laid out their vision of a secure transition to a decarbonised 2030 power sector in Ireland, compliant with the 70% renewable electricity ambition of the *Climate Action Plan 2019*. In the same month, the Irish Government published a revised *Climate Action Plan* that stated an increased ambition of 80% renewable electricity by 2030, and a complementary target of reducing power sector emissions to between 2 and 4 million tonnes of CO_2 per year.

In this study we have set out to explore a series of Pathways out to 2030 for the Irish power sector, to quantify the cumulative carbon budget unlocked by going beyond the *Shaping our Electricity Future Roadmap* and achieving the 2030 targets of the *Climate Action Plan 2021*:

- We first modelled two Pathways, **Rapid Delivery** and **Delayed Delivery**, which each achieve the same decarbonised Irish power sector by the end of 2030, but explore the different deployment rates of wind and solar capacity following RESS auctions, as fast and as slow as is compliant with the current timetable respectively.
- We then analysed a final Pathway, **Accelerated Decarbonisation**, in which all of the power sector targets of the *Climate Action Plan 2021* are achieved, or exceeded, including the delivery of 8.2 GW of onshore wind, 5 GW of offshore wind, and 3 GW of solar PV capacity. This renewable capacity is delivered as fast as achievable under current policy, complemented by investment in zero-carbon system services, and network solutions.

Apart from the volume and deployment rate of renewable capacity, and the adoption of zero-carbon system services, each of the assumptions underlying our three Pathways are aligned with those of EirGrid and SONI's *Shaping our Electricity Future Roadmap*. We have compared the results of our Pathways to those of a modelled Baseline, which aligns with the *Shaping Roadmap* for all assumptions, and achieves the now superseded target of 70% renewable electricity by 2030.

In this study, we have not only modelled the Irish power sector at the market and system levels, but also at the network level with **modelling of hourly power flows through each transmission line in Ireland**. This circuit-level analysis, enabled by a collaboration between Baringa and TNEI, has allowed us to determine the potential options for spatial deployment of generation assets, and evaluate the hourly constraint of renewables. This provides a holistic view of our Pathways beyond that of previous market studies, and aligns with the modelling approach used by transmission system operators including EirGrid.

Table 1 below presents the key assumptions of the Shaping our Electricity Future (SOEF) Baseline and three Pathways we have modelled in this study.

Table 1: DS3 limit and Irish year-end renewable capacity assumptions of the Baseline and Pathways

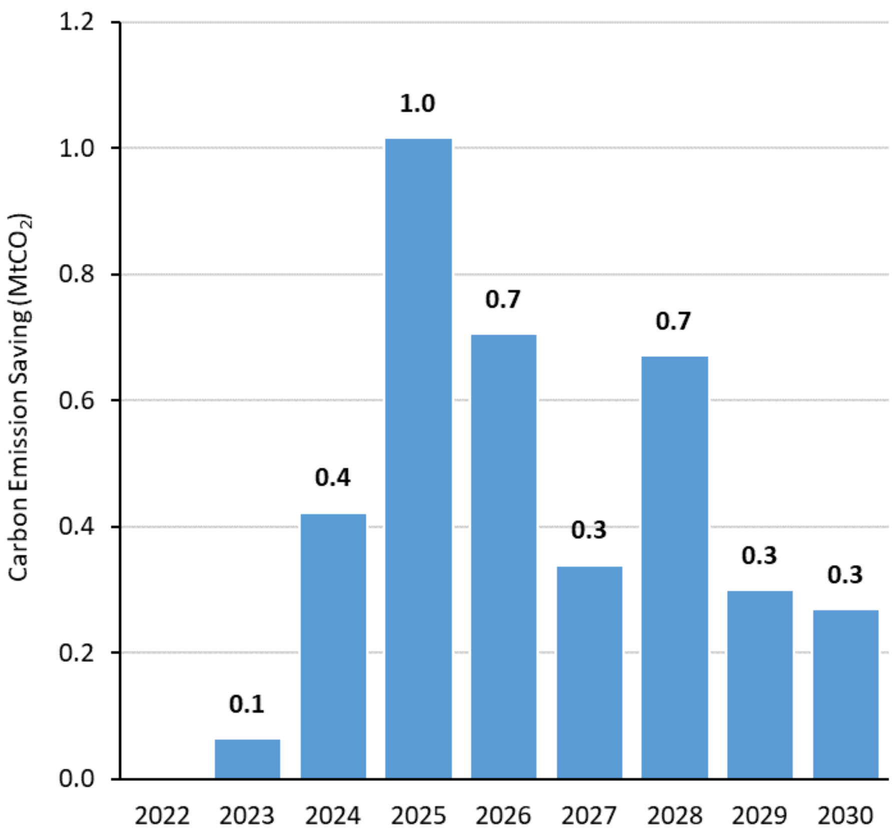
Pathway Assumptions	Units	2022	2023	2024	2025	2026	2027	2028	2029	2030
SOEF Baseline										
SNSP limit	*%*	75%	75%	75%	85%	85%	85%	85%	85%	95%
Minimum units - ROI	*#*	4	4	4	4	4	3	3	3	2
Onshore wind	*MW*	4,600	4,770	4,900	5,030	5,170	5,300	5,430	5,570	5,700
Offshore wind	*MW*	30	30	30	30	1,000	2,000	3,000	4,000	5,000
Solar PV	*MW*	320	460	610	760	900	1,050	1,200	1,350	1,500
All Further Modelled Pathways										
SNSP limit	*%*	75%	75%	75%	85%	85%	95%	95%	95%	100%
Minimum units - ROI	*#*	4	4	4	3	2	2	1	1	0
Rapid Delivery										
Onshore wind	*MW*	4,730	4,940	5,790	6,760	7,000	7,000	7,000	7,000	7,000
Offshore wind	*MW*	30	30	30	30	30	30	2,560	3,780	5,000
Solar PV	*MW*	710	760	1,680	2,740	3,000	3,000	3,000	3,000	3,000
Delayed Delivery										
Onshore wind	*MW*	4,730	4,780	4,780	5,030	5,520	7,000	7,000	7,000	7,000
Offshore wind	*MW*	30	30	30	30	30	30	980	1,930	5,000
Solar PV	*MW*	710	760	760	1,010	1,510	3,000	3,000	3,000	3,000
Accelerated Decarbonisation										
Onshore wind	*MW*	4,730	4,940	5,870	7,350	8,200	8,200	8,200	8,200	8,200
Offshore wind	*MW*	30	30	30	30	30	30	2,560	3,780	5,000
Solar PV	*MW*	710	760	1,410	2,420	3,000	3,000	3,000	3,000	3,000

The impact of renewable deployment rate on Irish CO_2 emissions

Figure 1 below presents the annual net CO_2 savings unlocked in Ireland in the Rapid Delivery Pathway by the deployment of wind and solar capacity at the fastest achievable rate over the decade based on current policy, i.e., projects are commissioned at the start of the delivery windows following each RESS auction. These net savings have been measured relative to the Delayed Delivery Pathway, which assumes that capacity is deployed around the long-stop dates of each auction; the latest delivery compliant with the current RESS schedule.

Evaluated at the system level, i.e., before the impact of transmission constraints, a total of 4 million tonnes of CO_2 can be saved in the Irish power sector by faster deployment of renewable capacity over the decade. This saving represents two years' worth of emissions at 2030 levels in either Pathway, despite both achieving Ireland's 2030 targets of 80% renewable electricity and 2 million tonnes of CO_2. Emissions remain persistently high in the early years of the decade, as a result of continued generation from carbon intensive fuels such as coal and peat. This 'locks in' a substantial accumulation of emissions, placing intense pressure on carbon budgets even with the most optimistic rate of renewable build-out under current policies. Our analysis shows that a total of 61 million tonnes of CO_2 are emitted from the Irish power sector between 2021 and 2030 at the system level in the Rapid Delivery Pathway, before network constraints are accounted for.

Figure 1: Avoided Irish system-level CO_2 emissions in Rapid Delivery relative to Delayed Delivery



An Accelerated Decarbonisation Pathway for Ireland

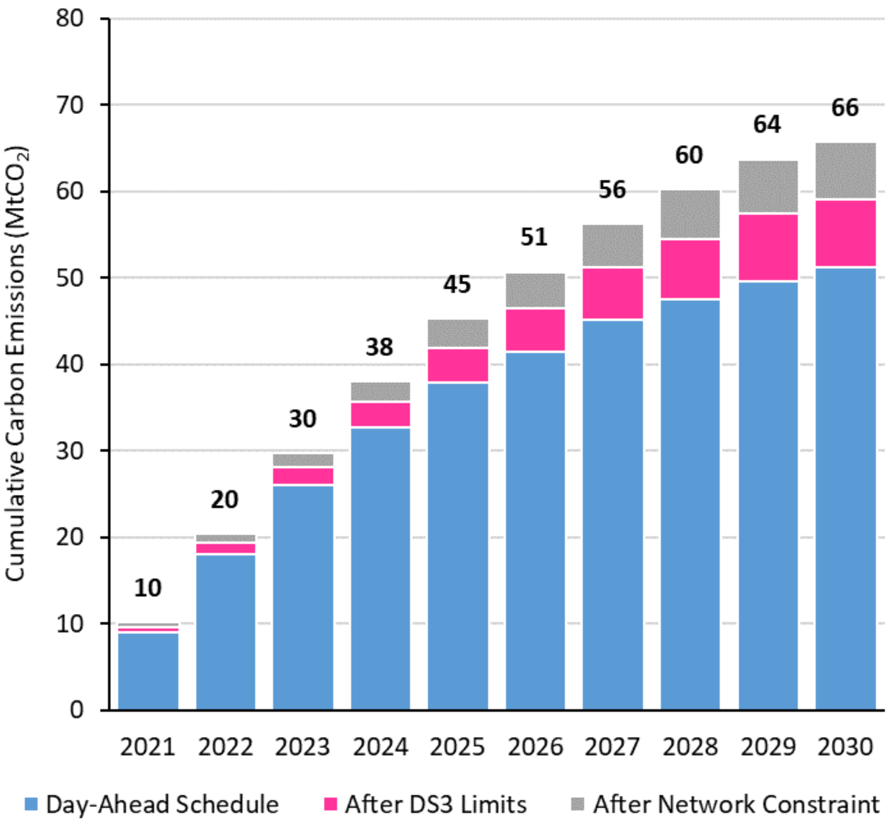
We have evaluated a final Pathway, Accelerated Decarbonisation, designed to explore the limit of ambition with respect to power sector decarbonisation in Ireland under current policy.

The Accelerated Decarbonisation Pathway delivers a 2030 power sector compliant with the 2 million tonnes of CO_2 ambition of the *Climate Action Plan 2021*, and exceeds the renewable electricity target with 90% of end consumer demand met by zero-carbon sources. On a cumulative basis however, 45 million tonnes of CO_2 are emitted in the first half of the decade alone, resulting from a continued reliance on carbon intensive fuels including coal and peat. Between 2021 and 2030, a total of 66 million tonnes of CO_2 is emitted from the Irish power sector in this Pathway, including emissions resulting from transmission constraints at the network level, as is presented below in Figure 2.

To achieve a Pathway to 2030 with cumulative power sector emissions below 66 million tonnes of CO_2, solutions must be found to the use of these carbon intensive fuels over the first half of the unfolding decade, beyond current policy in Ireland.

In comparison, the SOEF Baseline, which benefits from the optimistic *Shaping Roadmap* assumption of offshore wind deployment from 2026, updated to 2028 in the Pathways, results in a total of 72 million tonnes of CO_2 being emitted from the Irish power sector over the decade. The 6 million tonne CO_2 saving in Accelerated Decarbonisation represents the equivalent of three years' worth of power sector emissions by 2030.

Figure 2: Cumulative total power sector CO_2 emissions in Ireland in Accelerated Decarbonisation

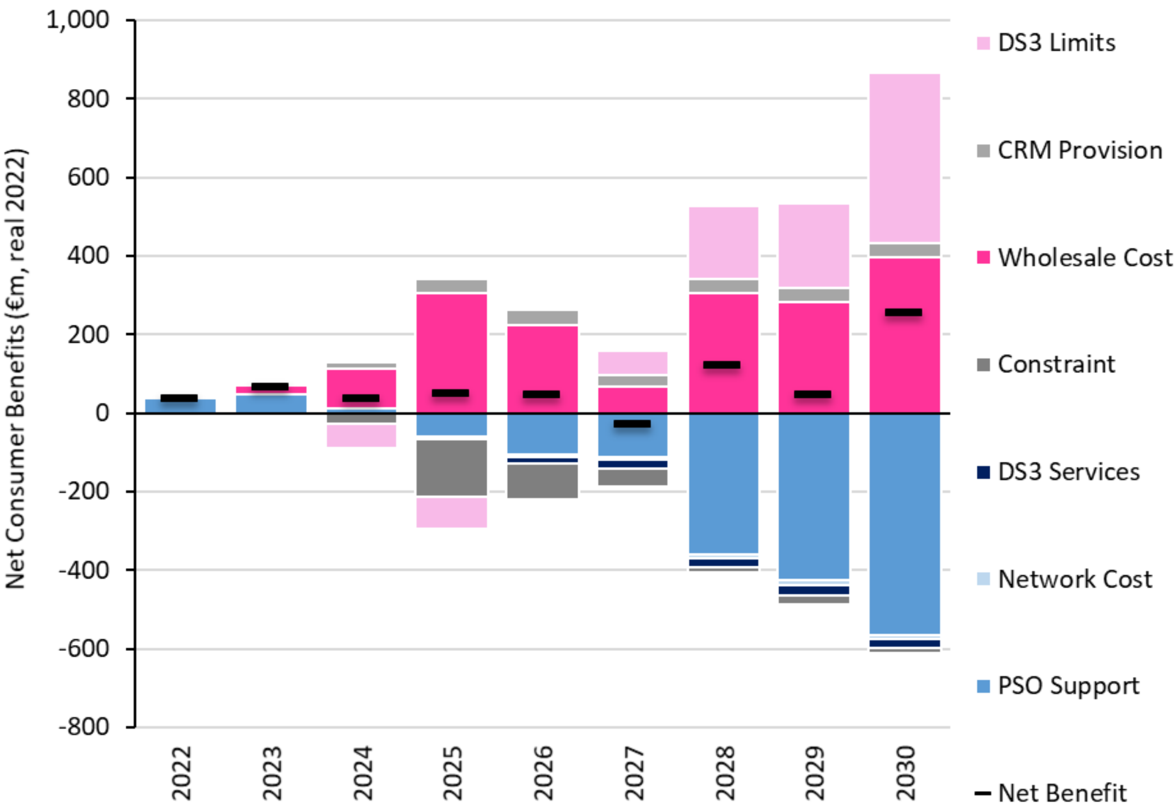


In addition to avoided CO_2, the Accelerated Decarbonisation Pathway offers significant net cost savings to end consumers compared to the SOEF Baseline, as presented below in Figure 3.

An overall net cost saving of over €600m was found to be conferred to end consumers in Ireland between 2022 and 2030 from the holistic cost-benefit analysis presented below, in which net benefits are presented as positive, and net costs as negative. The incremental cost of supporting renewable generators via the PSO levy and the greater cost of re-dispatching constrained renewable output are outweighed by the €1,700m net benefit provided by lower wholesale power prices. Zero-carbon system services, provided by incremental build-out of synchronous condensers and dedicated short-duration battery storage assets, provide a further net saving of €750m over the decade, unlocked by the unwinding of system-level DS3 limits at the back-end of the horizon, which greatly outweighs the cost of the assets. The annuitized incremental cost of the network development required beyond the Baseline, to enable the connection of additional renewable capacity and unlock the overall net benefit to end consumers, totals around €50m over the decade.

Achieving the rapid rate of renewable capacity deployment assumed in this Pathway requires the build-out of all network development projects assumed in the *Shaping Roadmap*, as well as incremental circuit upgrades beyond this. Where long lead times apply to network upgrades, and prevent their timely delivery in-line with the build-out of renewable capacity, strategic spatial deployment of enabling technologies can act to manage constraint across the Irish network, including STATCOMs, power flow control, and dedicated energy storage capacity.

Figure 3: Irish end consumer cost-benefit analysis of Accelerated Decarbonisation relative to SOEF



1 Introduction

The *Shaping our Electricity Future Roadmap*[1], a joint publication by the transmission system operators (TSOs), EirGrid and SONI, was released in November 2021. The publication set out the TSOs plans from the perspective of networks, engagement, operations, and the market, to support a secure transition to an Irish electricity system supplied by 70% renewable energy by 2030. This '70 by 30' target had been adopted by the Irish government in June 2019 in the initial publication of Ireland's *Climate Action Plan*[2], having been explored in Baringa's *70 by 30*[3] study.

Since the adoption of this target, the Irish power sector has seen holistic market and policy developments, with increasing ambition towards the deployment of renewable technologies, and overall sector decarbonisation. An updated *Climate Action Plan*[4], published in November 2021, confirmed a more ambitious target of 80% renewable electricity by 2030 as government policy. The Irish Government also confirmed a complementary target of reducing greenhouse gas emissions from the power sector to between 2 and 4 million tonnes of CO_2 ($MtCO_2$). This target reflects a similar increase in ambition, with the 2019 release having stated an indicative target of between 4 and 5 $MtCO_2$. The benefits to end consumers of achieving the target of less than 2 million tonnes of CO_2 from the power sector had been explored in Baringa's *Endgame*[5] report, published in June 2021.

A cumulative 'carbon budget', a binding limit on greenhouse gas emissions across all sectors of the Irish economy, was proposed by the Climate Change Advisory Council in October 2021[6], and adopted as a binding government target in April 2022[7]. The budget limits Irish emissions to the equivalent of 295 $MtCO_2$ over the 2021-2025 period, and a further 200 $MtCO_2$ in 2026-2030. Despite a shift in attention towards cumulative emissions in Ireland, a carbon budget for the power sector over the next decade has not yet been finalised. An indicative sectoral carbon budget has been suggested by Dr Paul Deane of University College Cork; a total of around 55 $MtCO_2$ over the 2021-2030 period[8].

In this study we have modelled the Irish power sector in a series of Pathways out to 2030 to explore the impact of the timing and volume of renewable build on carbon budgets and the power system. We have gone beyond the system-level modelling methodology used in previous studies[9], by layering on a network-level representation of the Irish system through the collaboration of Baringa and TNEI.

Baringa's pan-European power market model first simulated the hourly plant dispatch in the island of Ireland at the system level, considering both day-ahead schedule positions and re-dispatch of plant required to account for system-level constraints. TNEI then modelled the all-island system in our final, most decarbonised, Pathway at the network level, determining the potential options for spatial deployment of renewables, required network reinforcement, and further re-dispatch of plant resulting from transmission constraints.

[1] *Shaping our Electricity Future Roadmap*
[2] *Climate Action Plan 2019*
[3] *70 by 30*
[4] *Climate Action Plan 2021*
[5] *Endgame*
[6] *Letter to Minister Ryan, 25/10/21*
[7] Carbon Budgets
[8] *Goodbye Renewable Targets: Hello Carbon Budgets*
[9] Detail on previous Baringa reports is given in Appendix C.2.

Pathways to Ireland's 2030 power sector

We considered three Pathways in this study, each modelled at an hourly granularity from 2022 to 2030 inclusive. The first two Pathways both achieve the current 2030 power sector targets of 80% renewable electricity and 2 $MtCO_2$, but explore different deployment rates of wind and solar capacity procured in Renewable Electricity Support Scheme (RESS) auctions. Our final Pathway, Accelerated Decarbonisation, then explores the limit of ambition under current policy towards decarbonisation in the sector, and quantifies the cumulative CO_2 emissions that result. We have modelled each at the system level, and layered network-level considerations onto the Accelerated Decarbonisation Pathway. The three Pathways explored in this study are:

- **Rapid Delivery**: A Pathway in which future RESS auctions, assumed out to RESS 4[10], proceed according to the indicative schedule proposed by the Department of the Environment, Climate and Communications (DECC) in December 2021[11]. The commission of contracted capacity following each auction is concentrated towards the start of each delivery window, or the earliest feasible date. A total of 7 GW of onshore wind, 5 GW of offshore wind, and 3 GW of solar PV is deployed in Ireland by the end of 2030. The integration of this renewable generation capacity is enabled by the deployment of zero-carbon solutions to DS3 limits[12], such as synchronous condensers and dedicated battery storage capacity. Evaluated at the system level, the Irish ambition of 80% renewable electricity in 2030 is achieved, and emissions from residual fossil gas-fired assets fall below 2 $MtCO_2$ per year.
- **Delayed Delivery**: A Pathway in which an equivalent 7 GW of onshore wind, 5 GW of offshore wind, and 3 GW of solar PV capacity is deployed by the end of 2030 as in Rapid Delivery. Although RESS auctions proceed according to the same schedule, with auctions out to RESS 4 considered, the contracted renewable capacity is deployed towards the assumed long-stop dates of each auction. The majority of this new-build capacity is procured in later auctions, though the lower bound of DECC's indicative auction volume range is secured in all auctions. The 2030 targets of 80% renewable electricity and 2 $MtCO_2$ are also achieved in this Pathway, having been evaluated at the system level.
- **Accelerated Decarbonisation**: In this Pathway we explore the limit of ambition with respect to power sector decarbonisation in Ireland based on current policy. The *Climate Action Plan* target of 8.2 GW of onshore wind by 2030 is delivered. According to an aligned deployment schedule with Rapid Delivery, this penetration of onshore wind capacity is achieved alongside 5 GW of offshore wind, and 3 GW of solar PV. The increased ambition towards onshore wind capacity allows around 90% of the electricity demand in Ireland to be met by renewable sources in 2030, and enables emissions from the Irish power sector to achieve the 2 $MtCO_2$ target, including emissions resulting from transmission constraints at the network level.

[10] We have not assumed auctions beyond those detailed in the current schedule, out to RESS 4 and ORESS 2.

[11] Renewable Electricity Support Scheme – Schedule of Future Auctions

[12] Delivering a Secure, Sustainable Electricity System (DS3) is EirGrid's holistic programme of changes designed to enable power sector decarbonisation. 'DS3 limits' are requirements that the all-island system must meet in all hours to ensure system stability and security of supply. Market participants can provide 'DS3 services', ancillary products such as reserve, inertia, and reactive power, which are required to maintain the DS3 limits.

Each Pathway builds on the underlying scenario assumptions behind the *Shaping our Electricity Future Roadmap*, with the deployment of renewable capacity and enabling technologies going beyond that assumed by EirGrid and SONI. All scenario assumptions besides the rate and volume of renewable capacity deployment are aligned across the three Pathways. In this study we have evaluated our modelled Pathways against a Baseline, modelled at both the system level and network level, which employs the same assumptions as the *Shaping Roadmap*:

- **Shaping our Electricity Future (SOEF[13])**: A Baseline in which steady deployment of renewable generation capacity enables the Irish power sector to achieve the *Climate Action Plan 2019* target of 70% renewable electricity by 2030, but falls short of the revised 80% target. A total of 5.7 GW of onshore wind, 5 GW of offshore wind, and 1.5 GW of solar PV are commissioned in Ireland by 2030. Although the all-island DS3 limits are partially addressed by zero-carbon system services, curtailment[14] of renewable generation, and a reliance on fossil gas-fired plant to provide inertia, remains in 2030. Around 4 $MtCO_2$ is emitted from the power sector in 2030, including emissions from transmission constraints at the network level. This Baseline benefits from the optimistic *Shaping Roadmap* assumption that offshore wind capacity is delivered from 2026 onwards, an assumption that has been updated to 2028 in the Pathways to reflect the current view of industry.

All assumptions, besides the deployment of renewable capacity, zero-carbon solutions to DS3 limits, and network development, are aligned between the Baseline and each Pathway. Where scenario assumptions are not stated in the *Shaping Roadmap*, we have based them on other publicly available sources, as well as internal analysis and market intelligence.

The underlying assumptions of the Pathways are presented in this report, along with details of the methodologies used, and the results and implications of the study.

The remainder of this report is structured as follows:

- **Section 2** details the findings of the modelling of each Pathway, as well as the key assumptions and methodologies underpinning them;
- **Section 3** provides detail of the network solutions required to enable the Accelerated Decarbonisation Pathway;
- **Section 4** summarises the key findings of the study; and
- **Appendix A** to **Appendix D** provide further detail on the scenario assumptions used throughout the study, and overviews of Baringa and TNEI.

All monetary figures in this report are presented in real 2022 currency.

[13] To avoid ambiguity, in all further references to our modelled Baseline it is termed 'Baseline', 'SOEF', or 'SOEF Baseline', with references to EirGrid and SONI's *Shaping our Electricity Future Roadmap* document using the full name, or '*Shaping Roadmap*'.

[14] Definitions of dispatch-down actions in I-SEM are provided in Appendix A.1, with detail on mitigating solutions modelled in this study presented in Appendix A.2.

2 Pathways to Ireland's 2030 targets

2.1 Pathway assumptions

2.1.1 Overview of system-level assumptions

Our Baseline, and each of our modelled Pathways, include a series of assumptions aligned with the *Shaping our Electricity Future Roadmap* in 2030, with interim assumptions sourced from other EirGrid and SONI publications where appropriate. All assumptions are held consistent across the Baseline and Pathways, with three exceptions:

- DS3 limits, and the zero-carbon solutions to them, including dedicated batteries and synchronous condensers. The assumptions underlying these are aligned between Pathways, but exceed the corresponding assumptions of our Baseline.
- The capacity of wind and solar generation technologies installed in Ireland, and their rates of deployment. Each Pathway includes distinct renewable capacity assumptions, each of which exceed those of the Baseline.
- The incremental network development, and spatial deployment of enabling technologies, required to integrate renewable capacity onto the system. These assumptions, evaluated for the Accelerated Decarbonisation Pathway, are detailed in Section 3.

The key system-level assumptions underlying the modelling of the Integrated Single Electricity Market (I-SEM), comprised of Ireland (ROI) and Northern Ireland (NI), in this study are presented in Table 2 to Table 6 below.

Table 2: Key all-island assumptions

I-SEM Assumptions	Units	2022	2023	2024	2025	2026	2027	2028	2029	2030
Commodity & Carbon Prices										
Coal CIF ARA	*$/tonne*	117	98	87	81	79	77	76	74	73
Gas NBP	*€/MWh*	84	49	29	29	28	27	26	25	25
Oil Brent	*$/bbl*	82	74	69	70	73	76	79	82	84
Carbon EUA	*€/tonne*	88	87	86	89	93	96	100	103	105
Carbon UKA	*£/tonne*	79	74	74	76	80	83	87	91	93
Interconnector Capacity										
Import from GB	*MW*	950	950	950	1,450	1,450	1,450	1,450	1,450	1,450
Export to GB	*MW*	1,000	1,000	1,000	1,500	1,500	1,500	1,500	1,500	1,500
Import from France	*MW*	0	0	0	0	700	700	700	700	700
Export to France	*MW*	0	0	0	0	700	700	700	700	700

Table 3: DS3 limit assumptions in our Baseline and Pathways

I-SEM Assumptions	Units	2022	2023	2024	2025	2026	2027	2028	2029	2030
DS3 Limits (Baseline)										
SNSP limit	*%*	75%	75%	75%	85%	85%	85%	85%	85%	95%
RoCoF limit	*Hz/s*	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Minimum inertia	*GWs*	20	20	20	15	15	15	15	15	15
Minimum units - ROI	*#*	4	4	4	4	4	3	3	3	2
Minimum units - NI	*#*	3	3	3	2	2	2	2	2	2
DS3 Limits (Pathways)										
SNSP limit	*%*	75%	75%	75%	85%	85%	95%	95%	95%	100%
RoCoF limit	*Hz/s*	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Minimum inertia	*GWs*	20	20	20	15	15	15	15	15	0
Minimum units - ROI	*#*	4	4	4	3	2	2	1	1	0
Minimum units - NI	*#*	3	3	3	2	2	1	1	0	0

Table 4: Ireland year-end wind and solar capacity assumptions in our Baseline and Pathways

ROI Assumptions	Units	2022	2023	2024	2025	2026	2027	2028	2029	2030
SOEF Baseline										
Onshore wind	*MW*	4,600	4,770	4,900	5,030	5,170	5,300	5,430	5,570	5,700
Offshore wind	*MW*	30	30	30	30	1,000	2,000	3,000	4,000	5,000
Solar PV	*MW*	320	460	610	760	900	1,050	1,200	1,350	1,500
Rapid Delivery										
Onshore wind	*MW*	4,730	4,940	5,790	6,760	7,000	7,000	7,000	7,000	7,000
Offshore wind	*MW*	30	30	30	30	30	30	2,560	3,780	5,000
Solar PV	*MW*	710	760	1,680	2,740	3,000	3,000	3,000	3,000	3,000
Delayed Delivery										
Onshore wind	*MW*	4,730	4,780	4,780	5,030	5,520	7,000	7,000	7,000	7,000
Offshore wind	*MW*	30	30	30	30	30	30	980	1,930	5,000
Solar PV	*MW*	710	760	760	1,010	1,510	3,000	3,000	3,000	3,000
Accelerated Decarbonisation										
Onshore wind	*MW*	4,730	4,940	5,870	7,350	8,200	8,200	8,200	8,200	8,200
Offshore wind	*MW*	30	30	30	30	30	30	2,560	3,780	5,000
Solar PV	*MW*	710	760	1,410	2,420	3,000	3,000	3,000	3,000	3,000

Table 5: Key Ireland assumptions aligned over our Baseline and Pathways

ROI Assumptions	Units	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand[15]										
Annual demand[16]	*TWh*	34.4	36.6	38.4	39.6	41.1	42.6	44.3	45.6	46.9
Peak demand	*MW*	6,030	6,220	6,380	6,440	6,550	6,670	6,810	6,880	6,790
EV number	*k*	75	140	205	270	400	535	670	805	935
HP number	*k*	110	165	225	285	345	410	475	535	600
Generation Capacity										
Biomass	*MW*	70	70	120	120	120	120	120	120	120
Coal	*MW*	860	860	860	860	0	0	0	0	0
Fossil gas	*MW*	4,210	5,120	5,850	6,000	6,000	5,800	5,800	5,490	5,790
Hydro	*MW*	220	220	220	220	220	220	220	220	220
Oil	*MW*	1,540	1,540	940	940	940	300	300	300	300
Peat	*MW*	70	70	0	0	0	0	0	0	0
Waste	*MW*	80	80	80	80	80	80	80	80	80
Energy Storage Capacity										
Pumped hydro	*MW*	290	290	290	290	290	290	290	290	290
Battery (SOEF)	*MW*	450	550	650	760	950	1,140	1,320	1,510	1,700
Battery (Paths)	*MW*	450	550	650	810	1,180	1,370	1,550	1,740	1,930
Synchronous Condensers										
Condensers (SOEF)	*GWs*[17]	0.0	0.0	0.0	0.0	1.6	1.6	4.8	4.8	8.4
Condensers (Paths)	*GWs*	0.0	0.0	0.0	1.6	4.8	8.0	11.6	13.2	14.4

[15] As is detailed in Section 2.1.3, the Baseline and Pathways of this study assume Irish demand is aligned with that of the High Scenario in EirGrid and SONI's *Generation Capacity Statement 2021*, as was assumed in the *Shaping Roadmap*.

[16] Excludes demand from storage assets.

[17] Gigawatt-seconds (GWs) are units of inertia and are not synonymous with Gigawatts (GW). 1 GWs is equal to 1,000 MWs. The synchronous condensers in this study have a ratio of inertia produced per electricity used of 400 MWs per MW, i.e., a 4,000 MWs asset would require 10 MW of import capacity to power it.

Table 6: Key Northern Ireland assumptions aligned over our Baseline and Pathways

NI Assumptions	Units	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand										
Total demand	*TWh*	8.8	8.9	9.0	9.2	9.3	9.4	9.6	9.6	10.2
Total peak demand	*MW*	1,540	1,510	1,500	1,500	1,490	1,480	1,470	1,440	1,470
EV number	*k*	15	30	45	65	105	145	190	230	275
HP number	*k*	25	30	35	40	45	50	55	60	65
Generation Capacity										
Onshore wind	*MW*	1,320	1,440	1,590	1,730	1,880	2,020	2,160	2,310	2,450
Offshore wind	*MW*	0	0	0	0	0	0	0	0	100
Solar PV	*MW*	280	310	350	390	430	480	520	560	600
Biomass	*MW*	0	0	0	20	30	50	70	100	100
Coal	*MW*	400	400	0	0	0	0	0	0	0
Fossil gas	*MW*	1,020	1,020	1,580	1,910	1,770	1,770	1,770	1,870	1,920
Hydro	*MW*	0	0	0	0	0	0	0	0	0
Oil	*MW*	490	490	350	350	250	250	250	250	250
Peat	*MW*	0	0	0	0	0	0	0	0	0
Waste	*MW*	30	30	30	30	30	30	30	30	30
Energy Storage Capacity										
Pumped hydro	*MW*	0	0	0	0	0	0	0	0	0
Battery (SOEF)	*MW*	140	160	190	220	230	250	270	280	300
Battery (Paths)	*MW*	140	160	190	270	300	320	340	350	370
Synchronous Condensers										
Condensers (SOEF)	*GWs*	0.0	0.0	0.0	0.0	0.4	0.4	1.2	1.2	1.6
Condensers (Paths)	*GWs*	0.0	0.0	0.0	0.4	1.2	2.0	2.4	2.8	3.2

2.1.2 Commodity and carbon prices

We have derived our commodity and carbon price assumptions for this study from a combination of traded forward prices, and the *International Energy Agency World Energy Outlook (IEA WEO) 2021* publication. We have aligned our assumptions between the Baseline and each modelled Pathway.

In the years 2022 to 2024 inclusive, we have sourced our price assumptions for each commodity from their respective traded monthly forward prices, as of the 7th of January 2022. We have then linearly interpolated our projections on a quarterly basis from their values in Q4 2024, to our assumed 2030 values, each described below.

Since the 7th of January, traded forward prices for fossil fuels have increased as a result of the Russian Invasion of Ukraine. Although this impact has not been captured under the assumptions of this study, the commodity price increases would act to drive up the net benefits to end consumers of our Accelerated Decarbonisation Pathway over the SOEF Baseline, relative to those presented in Section 2.3.4. This increase in net benefits would result from reduced net costs incurred under the Public Service Obligation (PSO) levy (detailed in Section 2.2.4), and increased net benefits conferred via the wholesale market (Section 2.2.8) and imperfections charge (Sections 2.2.7 and 2.2.10).

For CIF ARA[18] hard coal and Brent Crude[19] oil, we have aligned our 2030 figures with the Stated Policies scenario of the *IEA WEO 2021*; 73 $/tonne and 84 $/bbl respectively.

We have assumed that by 2030, the price of NBP[20] fossil gas is set by the cost of HH[21] fossil gas imported as liquified natural gas (LNG) from the United States. The price of delivered fossil gas has been assumed to include the costs of liquefaction, transport, and regasification, in addition to the 3.9 $/MMBtu cost of traded HH fossil gas in the Stated Policies scenario of the *IEA WEO 2021*; totalling 64 p/therm or 25 €/MWh in 2030. For each year from 2025 onwards we have overlayed our interpolated NBP prices with a monthly seasonality calculated based on historical variation seen in European fossil gas prices.

The cost of fossil gas delivered to each power plant in the all-island system has been assumed to include either an annual (per kW) or short-term (per MWh) gas capacity charge, sourced from Gas Networks Ireland (GNI)[22] or Gas Market Operator Northern Ireland (GMO NI)[23] for plant in Ireland and Northern Ireland respectively. Fossil gas-fired plant are assumed to switch from annual to short-term tariffs as their load factors decrease from historical outturn, and it becomes profitable to do so.

We have aligned our 2030 assumptions for EUA[24] and UKA[25] carbon prices with the non-ETS price ambition of 100 €/tonne as stated in the *Climate Action Plan 2021*, which we have inflated to 105 €/tonne in real 2022 currency.

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[18] North-West European coal price (Amsterdam-Rotterdam-Antwerp) including cost, insurance, and freight.
[19] North-West European crude oil hub based in the North Sea.
[20] National Balancing Point, a virtual trading hub for fossil gas based in the United Kingdom.
[21] Henry Hub, a physical trading and distribution hub for fossil gas based in Louisiana, United States.
[22] Gas Networks Ireland 2021/22 Tariffs
[23] Gas Market Operator NI 2021/22 Tariffs
[24] European Union Allowances, carbon credits used within the EU Emissions Trading System (EU ETS).
[25] United Kingdom Allowances, carbon credits used within the UK Emissions Trading System (UK ETS).

2.1.3 Electricity demand

Our demand assumptions consist of two evolving tranches of load on the all-island system over the modelled horizon:

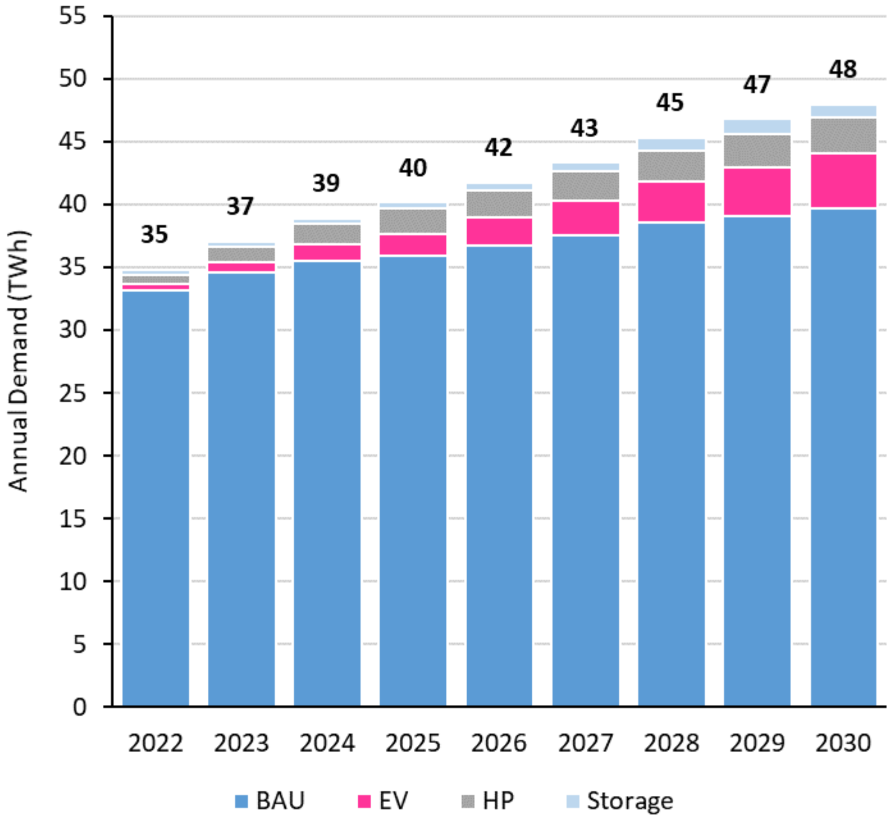
- A relatively inflexible business-as-usual (BAU) component, representative of rigid domestic, commercial, industrial, and data centre demand. We have sourced our BAU demand figures from the total demand assumptions of the High Scenario of EirGrid and SONI's *Generation Capacity Statement (GCS) 2021*[26], as was assumed in the *Shaping our Electricity Future Roadmap*, having subtracted the contribution of electric vehicles (EVs) and heat pumps (HPs) from the annual totals. The *Shaping Roadmap* included some deviation in annual total and peak demand from the *GCS 2021* in the year 2030, which we have included in our assumptions. Annual BAU demand in Northern Ireland totals around 9 TWh by 2030. Data centres make up an increasing proportion of Irish demand through the horizon, contributing around 35% of the 40 TWh of BAU demand in 2030. A constant degree of flexibility is included within this BAU component; around 360 and 120 MW[27] in Ireland and Northern Ireland respectively is assumed to be able to turn-down during hours of system tightness, with a further 160 and 50 MW being able to shift load profile within each day.
- A more flexible contribution from EVs and HPs. We have assumed a linear increase from the 45,000 registered EVs in Ireland as of the *Climate Action Plan 2021* to the roughly 270,000 projected in 2025 in the Community Action scenario of EirGrid's *Tomorrow's Energy Scenarios (TES) 2019*[28], and a further linear growth to the 935,000 assumed in the *Shaping Roadmap* by 2030. We have aligned our EV efficiency assumptions with those of the *TES 2019*. We have applied a similar approach to HP deployment, assuming linear growth out to the *TES 2019* figure by 2025 (282,000), and the *Shaping Roadmap* value in 2030 (600,000). We have estimated our 2022 Irish HP figure of around 51,000 using data on new dwelling completions and retrofitted dwellings, and indicative assumptions on the proportions of these fitted with HPs. We have applied these same methodologies in Northern Ireland, reaching 273,000 EVs and 67,000 HPs in 2030. The relative flexibility of these technologies is assumed to increase over time in both jurisdictions, with around 25% of EVs and 7% of HPs in 2030 able to shift their hours of charge within day in response to price signals, up from 15% and 3% respectively in 2025.

The total annual Irish demand assumed in this study is presented in Figure 4 below. In aggregate, the assumptions detailed above result in a roughly 80:20 split between Ireland and Northern Ireland in each year. This demand-weighted ratio has been used throughout this study to divide the assumed deployment of dedicated DS3 service capacity such as synchronous condensers, as well as system-level costs and benefits such as the cost of procurement in the capacity market (as is the case under current policy). We have aligned our demand assumptions between each Pathway, and the Baseline.

Sources of flexible demand, such as the EVs and HPs detailed above, offer solutions to mitigate the oversupply of renewables in the day-ahead schedule in Ireland, when deployed in combination with further sources of system flexibility such as interconnection and energy storage capacity. Each of these solutions is modelled within the Baseline and Pathways, as is detailed in Appendix A.2.

[26] *Generation Capacity Statement 2021*
[27] European Commission study on demand-side response
[28] *Tomorrow's Energy Scenarios 2019*

Figure 4: Annual electricity demand assumptions in Ireland



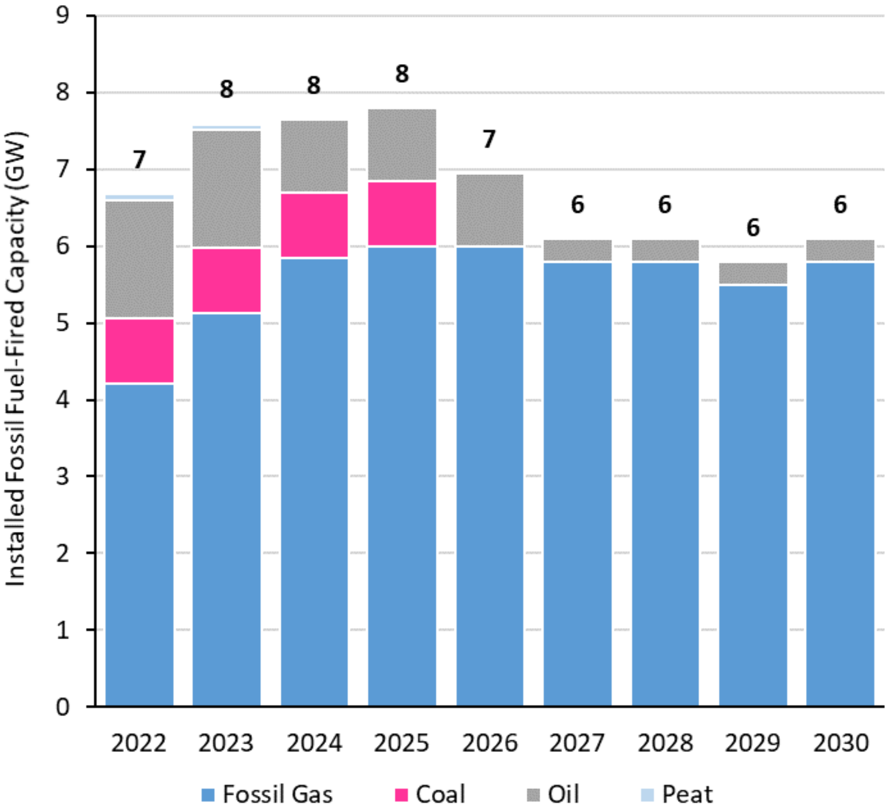
2.1.4 Dispatchable generation, energy storage, and DS3 service capacity

We have aligned our assumptions around the build-out and decommissioning of plant in I-SEM with that stated in the *Shaping our Electricity Future Roadmap* in our Baseline, and each modelled Pathway. Where assumptions are not provided in the *Shaping Roadmap*, we have first aligned our decommissioning schedule of existing fossil fuel-fired plant, and the commissioning of short-term capacity, with the *GCS 2021*. We have then used Baringa's in-house capacity market model to simulate the Capacity Remuneration Mechanism (CRM) out to 2030 across Ireland and Northern Ireland, to determine the necessary build-out of fossil fuel-fired capacity to maintain a de-rated capacity margin (DRCM) of around 4%, net of the all-island reserve requirement.

Our annual assumptions for installed fossil fuel-fired capacity in Ireland are presented in Figure 5 below. The stated intent from the Commission for Regulation of Utilities (CRU), echoed in the *Climate Action Plan 2021*, to procure 1,950 MW of new-build de-rated fossil gas-fired capacity in Ireland by Q3 2025 is achieved. By 2030, around 5,800 MW of fossil gas-fired capacity is installed in Ireland, with a further 1,900 MW installed in Northern Ireland. In alignment with the *GCS 2021*, coal and peat-fired generation is assumed to be phased-out in Ireland by 2025 and 2024 respectively, with the decommissioning of Moneypoint and biomass conversion of Edenderry 1. A residual 300 MW of oil-fired capacity remains in Ireland throughout the horizon, as is assumed in the *Shaping Roadmap*.

The modelled fossil fuel-fired capacity is accompanied by renewable technologies including biomass, reaching 120 and 100 MW in Ireland and Northern Ireland respectively by 2030, and around 220 MW of hydro capacity in Ireland throughout the horizon. In alignment with EirGrid and SONI's methodology in the *GCS 2021*, half of the generation from the 80 and 30 MW of waste-to-energy capacity in Ireland and Northern Ireland respectively is assumed to be renewable. Our modelled deployment schedules for wind and solar capacity, and the methodology behind them, are presented in Section 2.1.6.

Figure 5: Fossil fuel-fired installed generation capacity assumptions in Ireland



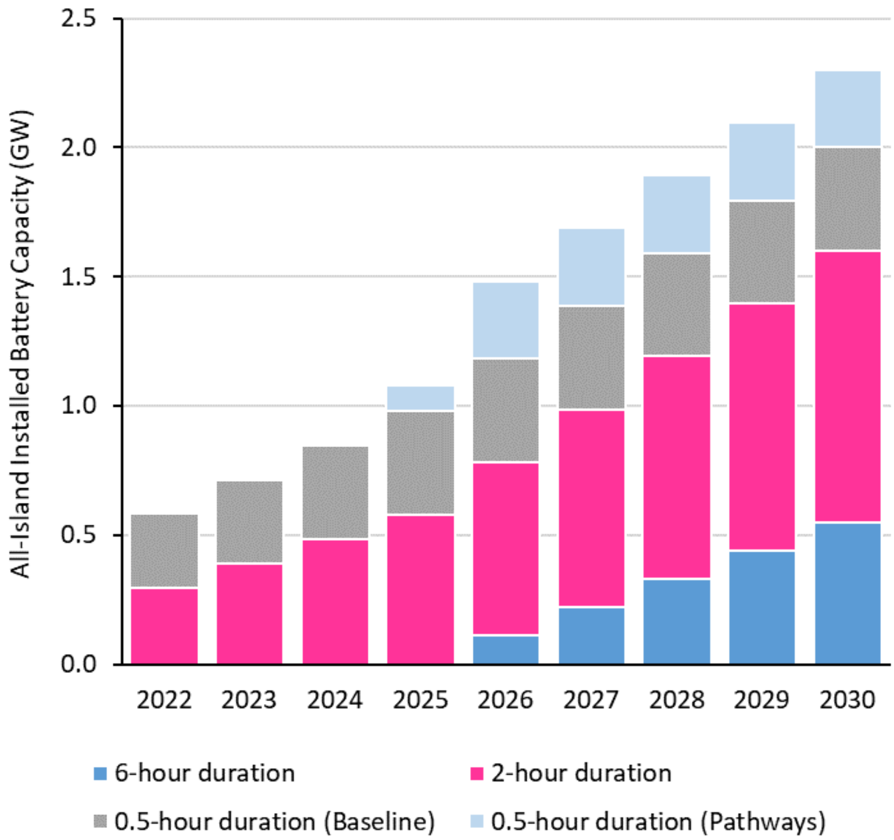
We have based our all-island energy storage deployment assumptions on those detailed in the *Shaping Roadmap*, namely:

- Linear growth in 0.5-hour duration battery capacity from today's levels to 350 MW in Ireland and 50 MW in Northern Ireland by 2025;
- Linear growth in 2-hour duration battery capacity from today's levels to 800 MW in Ireland and 250 MW in Northern Ireland by 2030; and
- Linear growth in 6-hour duration battery capacity from 0 MW in 2025 to 550 MW by 2030 in Ireland only.

As stated in the *Shaping Roadmap*, the 0.5-hour duration battery capacity is assumed to not participate in the day-ahead market, instead being dedicated to provision of fast-acting DS3 services, including frequency response (FFR), and operating reserve (POR – TOR2).

In our modelled Pathways, we have assumed an increased build of 0.5-hour duration batteries relative to the SOEF Baseline, in order to meet the all-island operating reserve requirement[29] with dedicated zero-carbon sources from 2025 onwards. Figure 6 below presents the total all-island battery capacity assumed in our Baseline, and the incremental capacity assumed in our Pathways. We have included the existing 290 MW Turlough Hill pumped hydro storage plant in the Baseline and all Pathways.

Figure 6: All-island installed battery capacity assumptions in our Baseline and Pathways



In addition to the dedicated operating reserve-providing batteries, we have assumed that synchronous condensers are deployed in I-SEM from 2026 in our Baseline. These assets are configured to provide zero-carbon inertia in our model simulations, reducing the reliance on fossil fuel-fired assets. We have assumed that a total of 10,000 MWs can be produced by these assets on an all-island basis by 2030, around two-thirds of the minimum requirement. The build-out of these assets is assumed to be divided between Ireland and Northern Ireland on a demand-weighted basis.

In our Pathways, we have assumed a greater build-out of synchronous condensers, 17,600 MWs by 2030, to enable both the minimum inertia and rate-of-change-if-frequency (RoCoF) limits to be met without reliance on fossil fuel-fired plant. Further detail is provided in Section 2.1.7.

[29] We have assumed that the requirement for each operating reserve product reaches 100% of the largest infeed by 2025. This represents an increase on current levels of POR and SOR, each currently procured at 75% of the largest infeed, bringing them in-line with the TOR1 and TOR2 requirements. The largest infeed is assumed to be the 500 MW East-West HVDC Interconnection (EWIC) until the 2026 commission of the 700 MW Celtic Interconnector.

2.1.5 Interconnection and external markets

In this study, the I-SEM day-ahead market is assumed to be coupled directly to the neighbouring British and French markets via interconnectors. Our assumptions around these interconnectors have been aligned across the Baseline and each modelled Pathway.

The Moyle Interconnector, which connects Northern Ireland and Scotland, is assumed to have achieved its maximum export capacity of 500 MW by April 2022, in-line with EirGrid's stated intent in the *GCS 2021*. Import capacity into Northern Ireland is assumed to remain at 450 MW. Dispatch of the East-West HVDC Interconnection (EWIC) between Ireland and Wales is also modelled throughout the horizon of this study, with a maximum capacity of 500 MW in each direction.

We have also included the Greenlink (500 MW to and from GB) and Celtic (700 MW to and from France) interconnectors in this study from 2025 and 2026 respectively, based on evaluations of their feasibility and business cases. The North-South Interconnector between Ireland and Northern Ireland is assumed to commission during 2025, in-line with the assumptions of the *GCS 2021*.

We have projected the installed dispatchable generation capacity in the neighbouring British and French markets using equivalent methodologies to that presented in Section 2.1.4 above. We have configured our installed wind and solar capacity assumptions in these markets to target approximate parity of day-ahead wholesale price between them and I-SEM by 2030 across the Pathways, with annual deployment based on available pipeline data and expected auction delivery volumes.

We have assumed that:

- Around 20 GW of onshore wind, 32 GW of offshore wind, and 20 GW of solar PV is commissioned in GB by 2030; and
- Around 36 GW of onshore wind, 6 GW of offshore wind, and 61 GW of solar PV is commissioned in France by 2030.

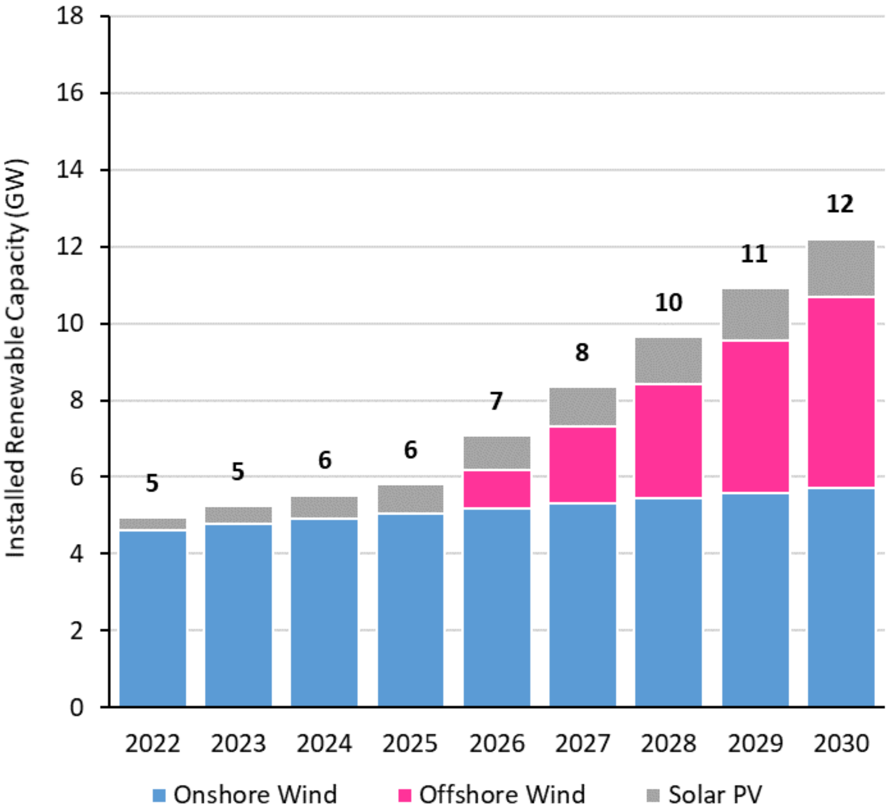
2.1.6 Wind and solar generation capacity

In the *Shaping our Electricity Future Roadmap*, EirGrid and SONI set out annual assumptions for the installed wind and solar capacity in each jurisdiction. In our SOEF Baseline, we have aligned our modelling assumptions with the linear growth by technology assumed in Ireland in the *Shaping Roadmap*, as is presented in Figure 7 below. In total, 5.7 GW of onshore wind, 5 GW of offshore wind, and 1.5 GW of solar PV is assumed to be installed in Ireland by 2030.

The Baseline, in alignment with the *Shaping Roadmap*, assumes that new-build offshore wind capacity is deployed in Ireland from 2026. We have updated this optimistic assumption to 2028 in each of our Pathways, to reflect the current industry view of the earliest connections of the Phase 1 offshore wind projects.

By the end of 2030 in each of our Pathways, we have assumed alignment with the 5 GW of offshore wind capacity, but have incrementally increased our assumptions for onshore wind and solar PV, to bridge the gap to the 2030 targets of the *Climate Action Plan 2021*.

Figure 7: Wind and solar generation capacity assumptions in Ireland in the SOEF Baseline



In December 2021, DECC published an indicative schedule for future RESS auctions, out to RESS 4 for onshore auctions and ORESS 2 for offshore auctions, following the first onshore auction that took place in July and August 2020[30]. We have used this schedule to determine the deployment rate limits for renewable capacity successful in these auctions, without violating the indicative upper and lower bounds for procured auction volumes, or moving from the targeted dates for the auctions themselves.

In the Rapid Delivery and Delayed Delivery Pathways, we have sought to isolate the impact of renewable capacity deployment rate on Ireland's cumulative power sector CO_2 emissions, by modelling two Pathways that achieve the same installed capacity by the end of 2030, but commission it at different rates in the preceding decade. Both Pathways consider 7 GW of onshore wind, 5 GW of offshore wind, and 3 GW of solar PV by the end of our modelled horizon, with Rapid Delivery assuming the fastest rate of deployment of RESS-backed capacity according to the DECC schedule, and Delayed Delivery assuming the slowest compliant roll-out of this capacity.

[30] R1AT

We have taken the following approach to project the capacity delivery schedules for wind and solar technologies in Ireland in these two Pathways:

- Each auction is assumed to proceed without delay, or advancement, to the proposed schedule as published by DECC. The indicative upper and lower bounds of auction volumes presented in the schedule have been taken as absolute limits, and we have converted them to equivalent generation capacities using load factors of 35% for onshore wind, 45% for offshore wind, and 11% for solar PV.
- The delivery windows for assets contracted in each auction are assumed to open in Q1 of the stated operational target year for that auction, and close 24 months later. This duration of delivery window is consistent with the 24-month window of the RESS 1[31] auction, and represents a small deviation from the 30-month window of RESS 2[32].
- The incremental capacity required to meet the assumed 2030 figures has been calculated relative to the 'end of 2021' values of the *GCS 2021*. This net capacity requirement is assumed to commission during the delivery windows of each auction, i.e., any projects supported by corporate power-purchase agreements (CPPAs) are assumed to deliver under the same timeline as projects supported by RESS contracts.
- The ratio of onshore wind to solar PV capacity procured in each future onshore auction[33] is assumed to be constant.
- In the Rapid Delivery Pathway, contracted capacity is deployed at the start of the commission windows for each auction. Earlier auctions are assumed to commission their upper volume bounds, and later auction procure their lower bounds, i.e., the assets are commissioned as soon as possible, without violating the bounds provided in the indicative auction schedule. This methodology has been applied separately for the onshore auctions, and the offshore auctions.
- In Delayed Delivery, contracted capacity is deployed as late as possible into each delivery window, with earlier auctions procuring their lower volume bounds, and later auctions procuring their upper bounds.

The results of this methodology are presented on a quarterly basis in Figure 8 and Figure 9 below, for Rapid Delivery and Delayed Delivery respectively. We have aligned our Northern Ireland wind and solar installed capacity assumptions with the *Shaping Roadmap* in our Baseline and all Pathways.

[31] RESS 1 Terms and Conditions

[32] RESS 2 Terms and Conditions

[33] The power market modelling phase of this study was completed ahead of the publication of the RESS 2 auction results, and therefore the assumed capacity procured in the auction has been varied between Pathways according to this methodology.

Figure 8: Quarterly wind and solar capacity assumptions in Ireland in Rapid Delivery

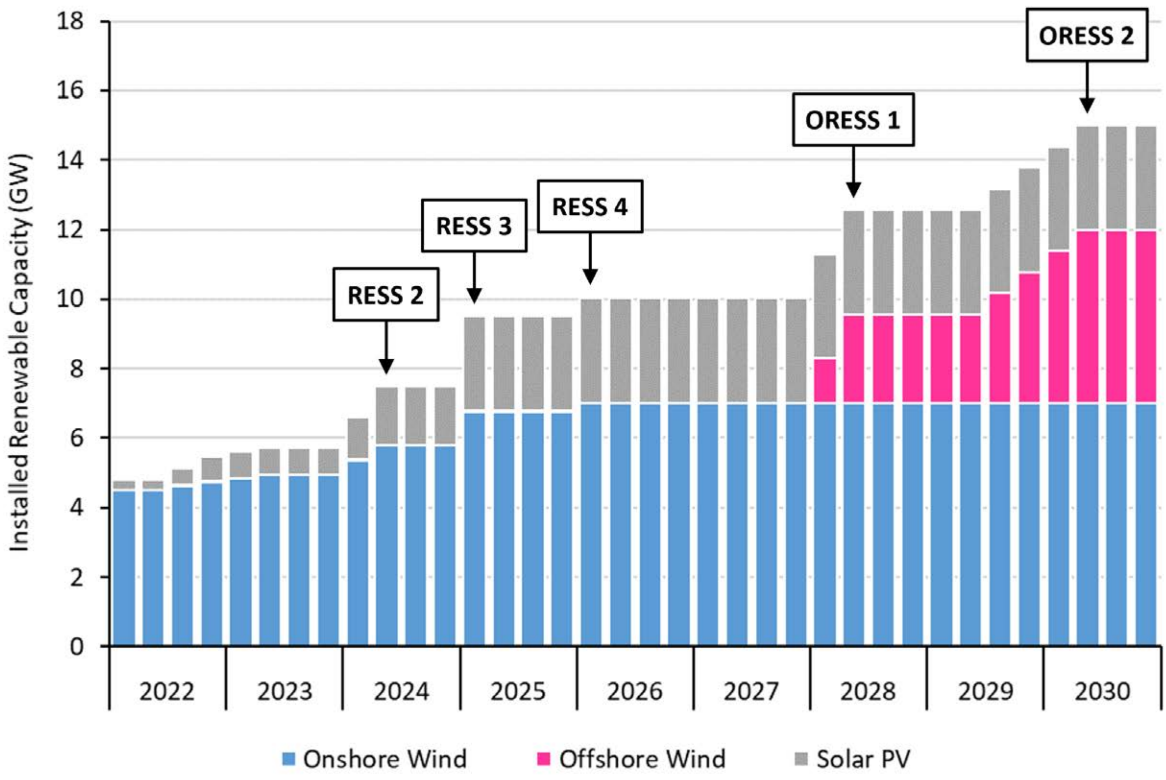
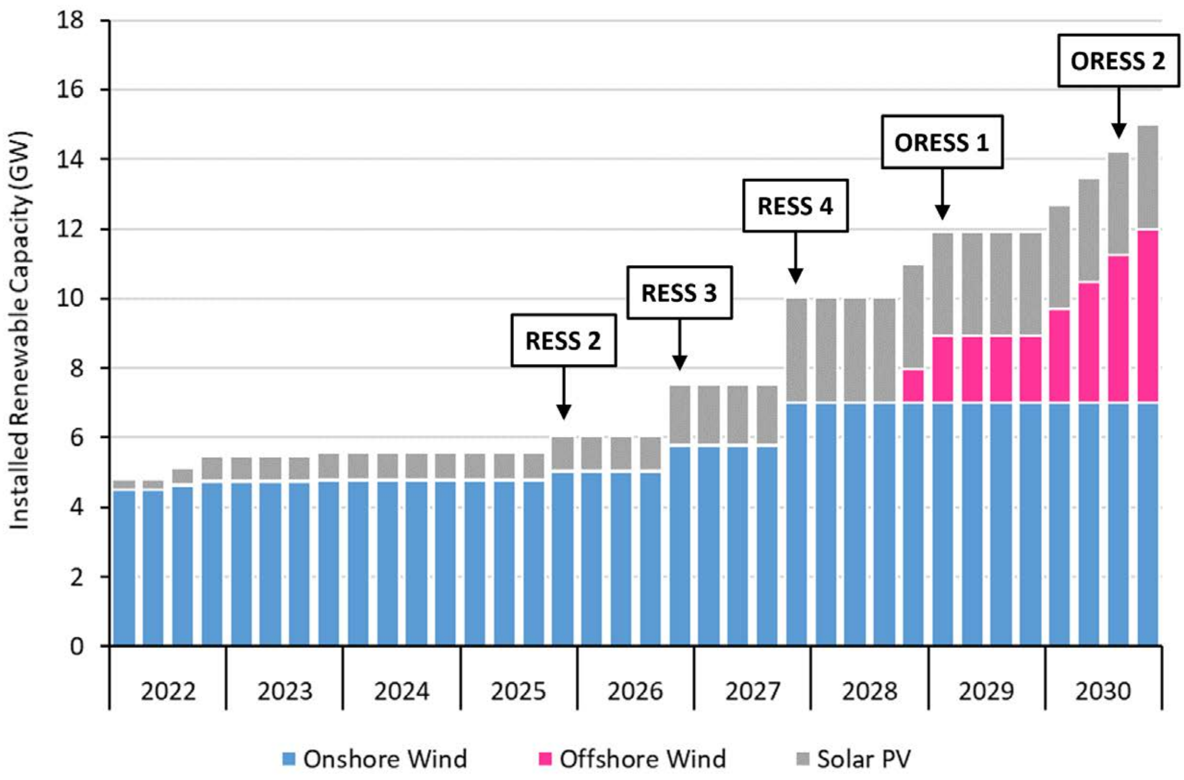


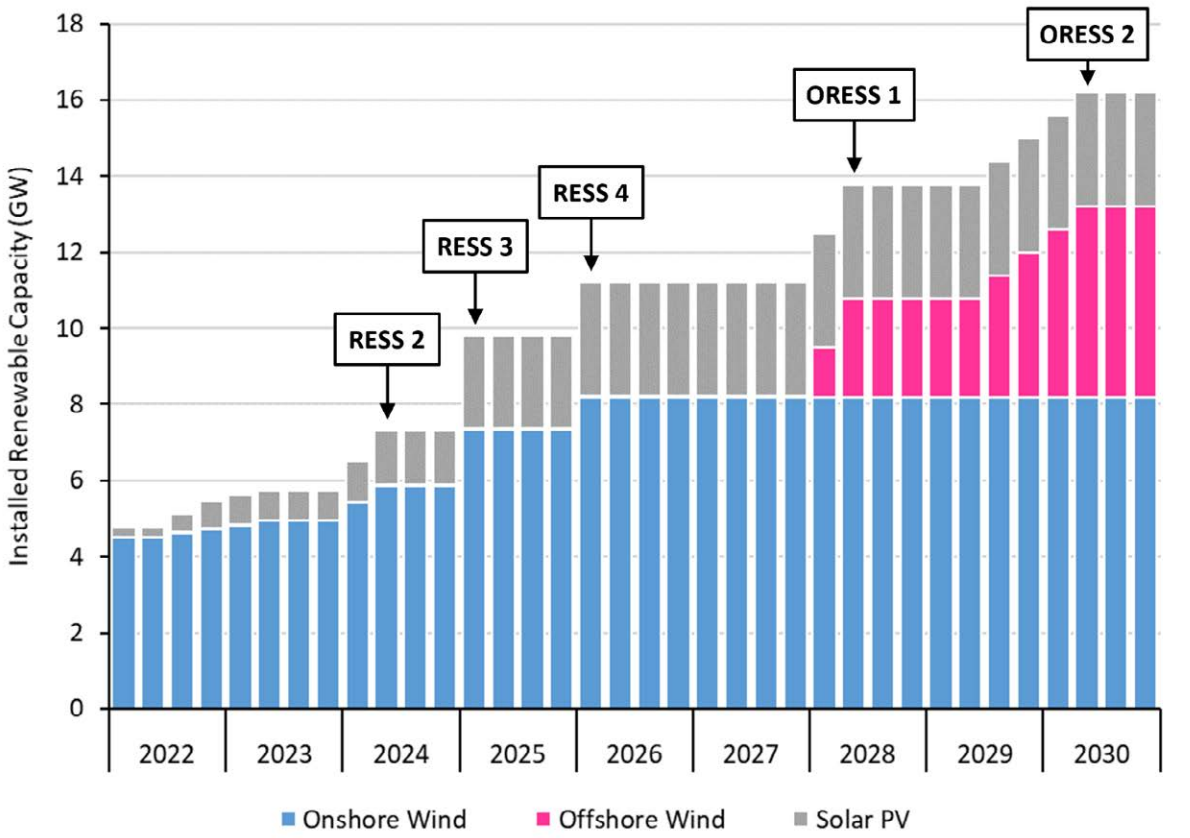
Figure 9: Quarterly wind and solar capacity assumptions in Ireland in Delayed Delivery



In our final Pathway, Accelerated Decarbonisation, we have assumed an aligned commissioning schedule of RESS-backed renewable capacity with Rapid Delivery, but with the *Climate Action Plan* target of 8.2 GW of onshore wind achieved in Ireland by the end of 2030. This Pathway also achieves the 5 GW target for offshore wind by 2030, and exceeds the 1.5-2.5 GW solar PV target, with 3 GW installed by 2030. Our quarterly wind and solar capacity assumptions for this Pathway are presented in Figure 10 below.

To achieve these capacity targets via RESS auctions, the upper bounds for volume procurement in RESS 2, RESS 3, and ORESS 1 are reached. However, in this Pathway as in the previous two, the minimum bound for ORESS 2 (15 TWh, or around 4 GW) is not achieved, as achieving this bound would take the installed capacity of offshore wind in Ireland beyond 5 GW, even when assuming the minimum bound of ORESS 1 is procured.

Figure 10: Quarterly wind and solar capacity assumptions in Ireland in Accelerated Decarbonisation



A summary of the key figures from DECC's indicative timetable, and the assumptions we have used in each of our Pathways, are presented in Table 7 below.

Table 7: Irish RESS auction schedule assumptions in our Pathways

RESS Assumptions	Units	RESS 1	RESS 2	RESS 3	RESS 4	ORESS 1	ORESS 2
Auction Timetable Details							
Lower volume bound	*GWh*	2,240	1,000	2,000	1,000	7,500	15,000
Upper volume bound	*GWh*	2,240	3,500	5,500	5,000	10,000	25,000
Indicative auction date	*N/A*	Q3 2020	Q2 2022	Q2 2023	2024	Q4 2022	2024/25
Indicative deployment	*N/A*	2023	2024	2025	2026	2027	2029
Rapid Delivery							
Total volume delivered	*GWh*	1,820	3,500	3,990	1,000	10,000	9,610
Onshore wind capacity	*MW*	440	850	970	240	0	0
Offshore wind capacity	*MW*	0	0	0	0	2,540	2,440
Solar PV capacity	*MW*	500	920	1,050	260	0	0
Start of deployment	*N/A*	Q3 2022	Q1 2024	Q1 2025	Q1 2026	Q1 2028	Q3 2029
End of deployment	*N/A*	Q2 2023	Q2 2024	Q1 2025	Q1 2026	Q2 2028	Q2 2030
Delayed Delivery							
Total volume delivered	*GWh*	1,340	1,000	2,960	5,000	7,500	12,110
Onshore wind capacity	*MW*	280	250	730	1,240	0	0
Offshore wind capacity	*MW*	0	0	0	0	1,900	3,070
Solar PV capacity	*MW*	500	250	740	1,250	0	0
Start of deployment	*N/A*	Q3 2022	Q4 2025	Q4 2026	Q4 2027	Q4 2028	Q1 2030
End of deployment	*N/A*	Q4 2023	Q4 2025	Q4 2026	Q4 2027	Q1 2029	Q4 2030
Accelerated Decarbonisation							
Total volume delivered	*GWh*	1,820	3,500	5,500	3,170	10,000	9,610
Onshore wind capacity	*MW*	440	940	1,480	850	0	0
Offshore wind capacity	*MW*	0	0	0	0	2,540	2,440
Solar PV capacity	*MW*	500	640	1,010	580	0	0
Start of deployment	*N/A*	Q3 2022	Q1 2024	Q1 2025	Q1 2026	Q1 2028	Q3 2029
End of deployment	*N/A*	Q2 2023	Q2 2024	Q1 2025	Q1 2026	Q2 2028	Q2 2030

2.1.7 DS3 limits

In the SOEF Baseline, we have aligned our assumptions for the system-level DS3 limits with those stated in the *Shaping Roadmap*. Where the dates of key limit relaxations are not stated in the *Shaping Roadmap*, we have aligned our assumptions with those of the Addressing Climate Change scenario of SONI's *Tomorrow's Energy Scenarios Northern Ireland (TESNI) 2020*[34].

Each of our Pathways assume greater deployment of zero-carbon system services than the *Shaping Roadmap*, enabling the integration of the greater renewable generation capacities presented in Section 2.1.6 above. We have assumed that by 2030, the all-island system is able to operate without the need to re-dispatch fossil fuel-fired plant to account for DS3 limits, with each being maintained by zero-carbon solutions.

In the short-term, we have aligned our limits across the Baseline and Pathways according to EirGrid and SONI's assumptions in their *Weekly Operational Constraints Updates*[35].

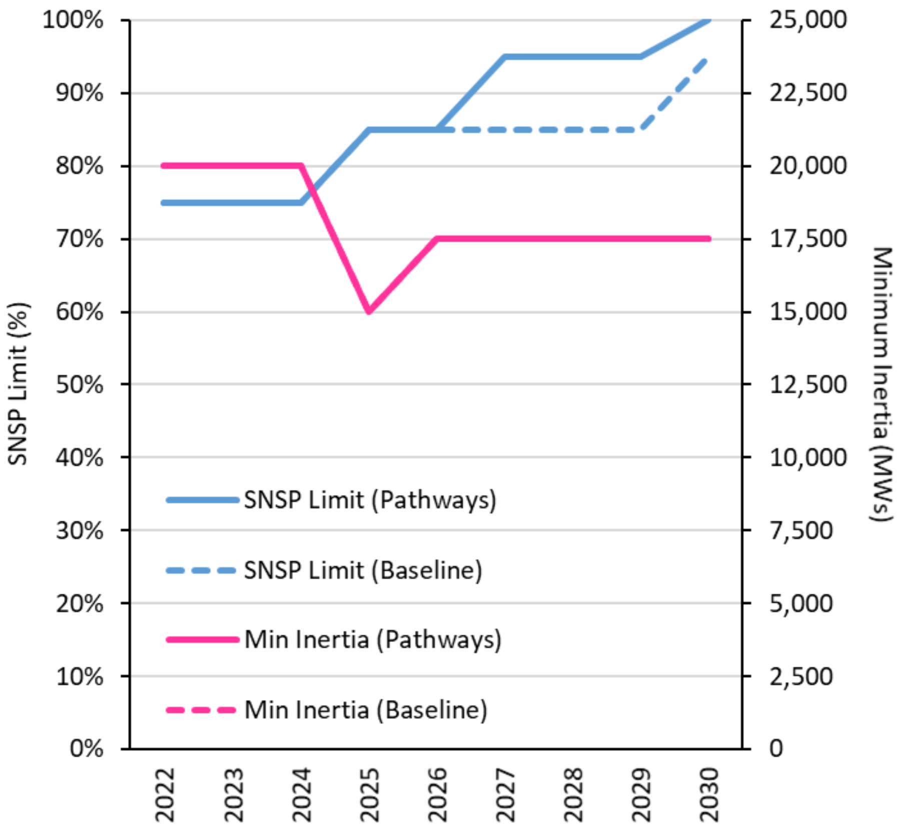
Figure 11 and Figure 12 below present our key DS3 limit assumptions in the Baseline and Pathways, with a comprehensive breakdown of all modelled limits detailed in Table 12 in Appendix B.1.

- **SNSP limit**: In our Baseline, we have assumed that the system non-synchronous penetration (SNSP) limit is increased from 75% to 85% in 2025, and to 95% in 2030, in-line with the assumptions of the *Shaping Roadmap*. In our Pathways, we assume that provision of zero-carbon system services enables 95% SNSP by 2027, and 100% by 2030.
- **RoCoF limit**: The current RoCoF limit of 1 Hz/s, under trial since the 17th of June 2020, is retained throughout the horizon in the Baseline and all Pathways.
- **Minimum inertia limit**: We have considered EirGrid and SONI's ambition of a 20,000 MWs minimum inertia limit trial from Q2 2022, aligned with the ambition of the *Shaping Roadmap*. A subsequent decrease of the limit to 15,000 MWs is assumed in 2025, aligned with the intent stated in the *TESNI 2020* Addressing Climate Change scenario. In our Pathways, we assume that provision of zero-carbon inertia from dedicated synchronous condensers is able to remove the inertial requirement on fossil fuel-fired plant by 2030. However, in both the SOEF Baseline and the Pathways, a total of 17,500 MWs is required from 2026 to maintain the RoCoF limit during hours in which the largest infeed, the 700 MW Celtic Interconnector, is active.
- **Min Gen limits**: In our Baseline, we have assumed that the minimum units for system stability (Min Gen) limit in Ireland is reduced from 5 to 4 during Q2 2022, as is the stated timeline for beginning the corresponding trial in the *Shaping Roadmap*. We have assumed that progress is made in reducing this limit to 2 units by 2030, in-line with the *Shaping Roadmap*. The Northern Irish limit is assumed to reduce from 3 to 2 units by 2025, and remain at 2 units for the rest of the modelled horizon, as stated in the *TESNI 2020* and *Shaping Roadmap* respectively. In our Pathways, we have assumed that the provision of inertia via synchronous condensers removes the need to re-dispatch fossil fuel-fired plant by 2030, in both Ireland and Northern Ireland.

[34] Tomorrow's Energy Scenarios Northern Ireland 2020
[35] SEM-O General Publications

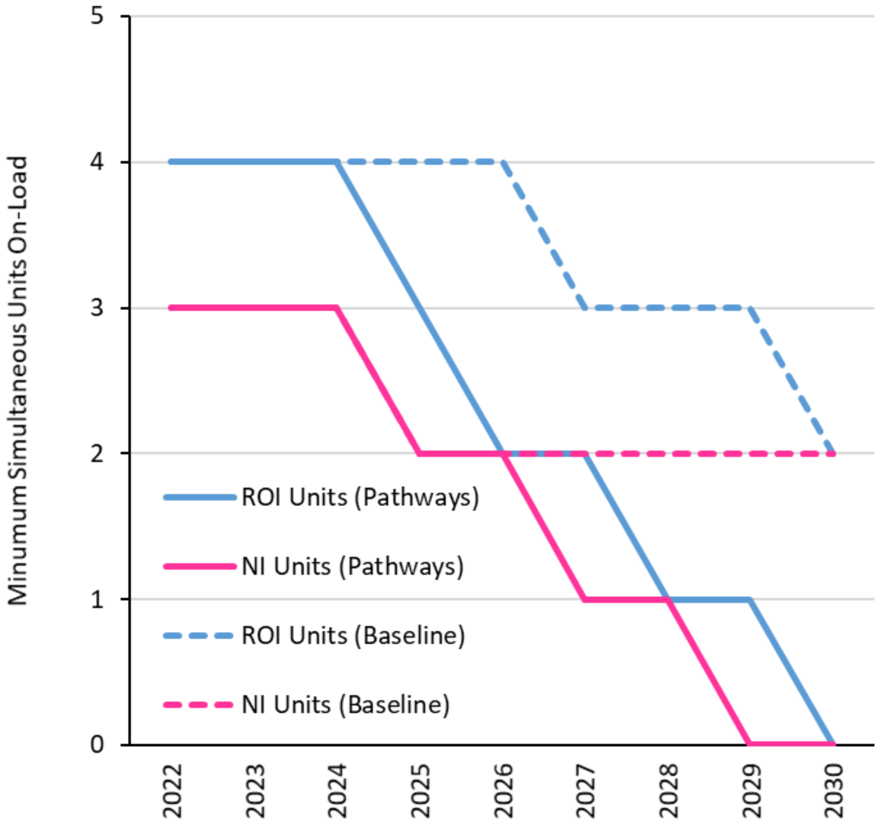
- **Locational limits**: In our Baseline, we have assumed that each of the Dublin and South generation constraints remain in 2030, with the Moneypoint (400 kV network) and North-West generation constraints having been relaxed. In our Pathways, we have projected an incremental schedule for the relaxation of these limits from 2024 onwards, according to the following high-level methodology:
  - Only one locational limit from each of the Dublin and South generation constraint sets can be reduced per year;
  - The limits with the greatest number of required units are reduced first; and
  - If multiple limits have the same unit requirements, the limits with the least binding demand thresholds are reduced first.

Figure 11: SNSP and minimum inertia[36] limit assumptions in the SOEF Baseline and our Pathways



[36] The minimum inertia limit as presented in Figure 11 includes the 17,500 MWs requirement associated with the RoCoF limit from 2026.

Figure 12: Min Gen limit assumptions in the SOEF Baseline and our Pathways



2.2 Modelling methodology

2.2.1 System-level dispatch modelling

Baringa has developed an in-house pan-European wholesale power market model covering Ireland, Great Britain, and the majority of mainland Europe for the purpose of power market studies. The model sits within PLEXOS, a third-party commercial software that is widely used in the power and utilities industry for market price projections, asset dispatch modelling, network analysis and other purposes. Our 'Pan-EU' model is configured with key inputs and scenario assumptions such as commodity prices, plant build and retirement, and hourly demand, wind, and solar profiles, and has detailed representations of generator technical parameters and interconnection between countries.

The model engine carries out a least cost optimisation across over 40 interconnected European markets to project hourly generator dispatch and market prices, taking full consideration of plant operational constraints.

The hourly demand shape and renewable profiles, in both I-SEM and other European markets, are based on outturn from a 'base weather year' of 2017. Wind and solar profiles have been corrected for dispatch-down actions. 2017 represents a broadly 'P50' year, with limited extreme weather or demand events throughout Europe.

Wind and solar assets are modelled as aggregated units in PLEXOS, with load factors and output profiles characteristic of averages over multiple site locations in each European market. Where support schemes incentivise variation in bidding behaviour between assets, we model several 'objects' in PLEXOS per market that reflect this behaviour. A second distinction is made between existing and new-build wind generators, with the latter assumed to have a higher load factor. We consider repowering of legacy wind plant towards the tail-end of their economic lifetimes.

The modelled representation of the all-island system closely replicates the way in which the market operates under the I-SEM structure. Generators are dispatched based on their short-run marginal costs, taking start fuel offtake, ramp rate, availability, minimum up and down time, heat rate variation, output capacity variation and other technical attributes into account.

Two runs take place in the model. In the first 'unconstrained' run, no system-level constraints are in place and plant are dispatched on a merit-order basis, representative of the day-ahead schedule. In a second 'constrained' run, the system is re-optimised, taking the DS3 limits presented in Section 2.1.7 above into account. Generators and interconnectors are re-dispatched from their ex-ante positions in accordance with these system-level limits. A comprehensive set of reserve requirements is also modelled in this run. The impact of transmission constraints is not considered in either market model run, instead being evaluated in a subsequent model, as is detailed in Section 2.2.2 below.

2.2.2 Network-level constraint re-dispatch modelling

In this study, TNEI have modelled a network-level representation of the I-SEM based on the results of Baringa's system-level power market modelling. TNEI's network model is based in Power System Simulator for Engineering (PSS®E), a software platform designed to simulate electrical transmission networks. The full details of the network-level modelling exercise conducted in this study are described in Section 3, in which we explore the network development required to enable the integration of renewable generation technologies in the Accelerated Decarbonisation Pathway.

In addition to the optimisation of network development projects, the model determines the hourly regional dispatch-down of renewable generation necessitated by transmission constraints, by consideration of circuit-level transmission limits in the all-island system, and the hourly generator dispatch from the power market model. TNEI have used the network model to evaluate the hourly constraint of renewables in Ireland in the Accelerated Decarbonisation Pathway for a series of spot years; 2022, 2025, 2027, and 2030. The results of the model, and our analysis detailed below, have been interpolated between these spot years.

Baringa have then optimised the re-dispatch of plant from their positions in the constrained market model run, in order to replace the renewable generation turned-down due to transmission capacity limits, representative of constraint actions taken by the TSOs in the balancing market. We have applied a three-step methodology at an hourly granularity:

- We have assumed that available battery storage assets are the first to be re-dispatched to replace the turned-down generation. Using the hourly energy in storage across the installed battery fleet, and the headroom[37] of the assets, we first calculated the maximum available response of the 2-hour and 6-hour duration batteries in Ireland. The 0.5-hour duration batteries have been assumed to not be available for turn-up actions to replace constrained generation, instead being dedicated to frequency response and operating reserve DS3 services. The available batteries are then assumed to only be turned-up in the balancing market if there are sufficient hours of zero, or negative, price in the day-ahead market[38] over the subsequent 12-hour period to recharge, and return to their positions prior to the constraint action. In this calculation we are modelling the battery storage assets as discharging to replace renewable electricity turned-down as constraint. **Storage assets strategically located behind transmission constraints are also able to reduce local renewable constraint levels by charging during hours of network congestion, an effect that grows exponentially with the duration of the storage technology, as was explored in Baringa's *Game Changer*[39] study of May 2022. Strategically located storage assets, up to 6 hours in duration, have been evaluated as an enabling network solution in the analysis presented in Section 3.**

[37] Headroom is defined as the difference between the hourly output of a generator, and its maximum possible.

[38] Hours of zero, or negative, price in the day-ahead market have been used here as a proxy for hours in which there is sufficient zero-carbon, and zero-marginal cost, generation to recharge the batteries without incremental CO_2 emissions or cost conferred to end consumers.

[39] *Game Changer*

- In hours of residual constraint after the battery re-dispatch, any generating biomass-fired plant with available headroom is assumed to turn-up, if the short-run marginal cost (SRMC) of the plant is lower than that of the most efficient fossil gas-fired plant generating on the system. **We have assumed that this turn-up of biomass-fired assets, while modelled as economic, is only possible from 2026 onwards, and represents a shift towards consideration of CO_2 emissions in constraint actions.**
- Any remaining constrained-down renewable output after the battery and biomass re-dispatch is then assumed to be met by incremental turn-up of fossil gas-fired assets. This final re-dispatch is allocated to plant generating in the constrained system-level power market model in that hour. Assets are assumed to be eligible for turn-up actions if they have headroom in the market model and are re-dispatched in order of SRMC, i.e., the least expensive plant is turned-up first, until the constrained electricity has been replaced.

We have assumed that constrained energy in Ireland is replaced by the turn-up of assets elsewhere in Ireland, i.e., we have not allowed Northern Irish assets to be re-dispatched in this optimisation. The incremental CO_2 emissions associated with these balancing actions have been quantified according to the volume of fossil gas required to make them. The costs incurred by end consumers have also been evaluated, as is detailed in Section 2.2.7. We have applied a consistent logic to the network-level modelling results of the SOEF Baseline, detailed in Section 3.2.1, to estimate the corresponding CO_2 emissions and end consumer costs associated with renewable constraint at an annual level.

2.2.3 Overview of end consumer cost-benefit analysis

We have calculated the net costs and benefits to end consumers in Ireland of the Accelerated Decarbonisation Pathway relative to the SOEF Baseline. We have analysed both the net costs and benefits unlocked at the system level, and those conferred at the network level. A comprehensive list of assumptions used in the cost-benefit analysis is presented in Table 17 in Appendix B.3. The net changes to the following end consumer costs relative to the Baseline have been considered:

- **PSO support costs**: The Public Service Obligation (PSO) levy cost of supporting renewable generation assets, considering deployment of incremental capacity, and movements in captured power prices;
- **Network development costs**: The cost of reinforcing the transmission network to enable incremental renewable capacity onto the system, including an assumed inflation of network development costs in a system with greater renewable penetration;
- **DS3 service costs**: The cost of procuring system services from zero-carbon sources including synchronous condensers and dedicated short-duration batteries;
- **Constraint costs**: Dispatch balancing costs resulting from the need to maintain circuit-level transmission limits;
- **Wholesale 'cost to load'**: The total cost paid out to generators to meet demand levels, considering movements in the wholesale power price;
- **CRM procurement costs**: The cost of provision of sufficient de-rated capacity as to ensure security of supply via the capacity market; and
- **DS3 limit costs**: Dispatch balancing costs arising from the need to maintain system-level DS3 limits.

2.2.4 Public Service Obligation (PSO) costs

The RESS subsidy scheme in Ireland supports renewable generation capacity by providing a two-way contract-for-difference (CfD)[40] at a fixed nominal strike price. As described in Section 2.1.6 above, we have assumed that all new-build wind and solar capacity in Ireland is supported by RESS, or an equivalent scheme, with the cost of support being paid by end consumers via the PSO levy. Renewable projects backed by CPPAs would reduce the net cost (or benefit) passed to end consumers via the PSO levy.

If the strike price of a RESS contract exceeds the average captured price for a renewable asset, then an additional cost is conferred to end consumers to support the generator. If the average captured price of an asset exceeds the strike price however, then end consumers will benefit from reduced payments for electricity supplied by that generator.

To calculate the cost or benefit borne by end consumers via the PSO levy, we have calculated the weighted average strike price of RESS-backed renewable assets in each year of the Baseline and Pathway. Where auction strike prices are known, i.e., for RESS 1[41] and RESS 2[42], we have converted these from nominal to real 2022 values. We have made the conservative assumption that the increase in strike prices seen in RESS 2 is retained for RESS 3, with capacity clearing at the contemporary value of RESS 2 contracts. For RESS 4 we assume that strike prices deliver the same value as those of the RESS 1 auction at the time of the later auction.

Beyond these auctions, we have assumed that average strike prices converge to the levelised cost of electricity (LCOE) for each successful technology, including offshore wind. We have used consistent load factor assumptions as those presented in Section 2.1.6.

Movements in the captured prices of wind plant also impact the cost of supporting assets under the legacy Renewable Energy Feed-in Tariff (REFIT) scheme in Ireland. We have assumed that the existing onshore wind plant under these one-way CfD[43] contracts have load factors of 30%. Unlike the two-way mechanism of RESS, the nature of the REFIT scheme prevents any cost savings being passed on to end consumers if average captured prices exceed corresponding strike prices.

[40] Under a two-way CfD, a generator receives a set value per MWh produced, the 'strike price'. When the market price falls below the strike price, the generator receives a top-up payment to supplement their market revenue. When the market price exceeds the strike price, the generator must pay back the difference. Under RESS, the strike price is nominal.

[41] *R1FAR*

[42] *R2PAR*

[43] Under a one-way CfD, a generator receives a set value per MWh produced, the 'strike price'. When the market price falls below the strike price, the generator receives a top-up payment to supplement their market revenue. When the market price exceeds the strike price, the generator does not have to pay back the difference, and secures additional revenue. Under REFIT, the strike price is indexed by CPI.

2.2.5 Network development costs

In Section 3 we detail the incremental network development beyond the SOEF Baseline to enable the Accelerated Decarbonisation Pathway. We have quantified the capital cost (CAPEX) of each asset, and annuitized them over an economic lifetime of 40 years, at a weighted average cost of capital (WACC) of around 5%. These annuitization assumptions are more conservative than the 50-year economic lifetime and 3.8% WACC assumed in the CRU's *Price Review 5 (PR5) Determination Papers*[44]. This conservative approach reflects the potential for inflated costs in a network with renewable penetration above the 70% targeted at the time of *PR5*.

Similarly, an annual operating cost (OPEX) of 0.3% per year has been assumed across the incremental development costs, inflated relative to typical values assumed in the market.

2.2.6 DS3 service provision costs

We have calculated the incremental technology investment in zero-carbon providers of DS3 services in the Accelerated Decarbonisation Pathway relative to the Baseline. We have assumed that the incremental build of synchronous condensers, which provide inertia to the system, and dedicated 0.5-hour duration batteries, which provide zero-carbon operating reserve services, is split between Ireland and Northern Ireland on a demand-weighted basis. The cost of procuring zero-carbon system services using these technologies has been assumed to equate to the annuitized cost of the assets.

An indicative all-in cost of a synchronous condenser is around €50m for a 4,000 MWs asset[45]. We have used this figure to calculate a 'per MWs' cost for this technology in I-SEM, and annuitized it across an assumed 15-year economic lifetime at a WACC of 12%. This cost of capital reflects a perceived level of risk around revenue certainty for dedicated zero-carbon inertia assets. Procurement of such a system service through long-term contracts, as is alluded to in the *Shaping Roadmap*, would act to mitigate this perceived risk premium, and offer lower costs to end consumers.

This cost has been combined with that of the incremental build of 0.5-hour duration batteries in the Accelerated Decarbonisation Pathway. We have calculated this latter cost component by annuitizing internal Baringa assumptions for capital and operating costs of this technology, assuming a 15-year economic lifetime and a WACC of 8%; resulting in an annuitized cost of around 55 €/kW in 2022, falling to around 45 €/kW by 2025 as capital costs are projected to decrease. These figures are net of the value provided to them in the CRM, as is considered in Section 2.2.9.

We have assumed that any incremental voltage requirements needed to achieve the DS3 limits of the Pathway can be met by renewable generation, synchronous condensers, and the transmission network reinforcement detailed above. The net cost of this is therefore considered within the PSO costs, network development costs, and DS3 service costs.

[44] *PR5*
[45] ESB Green Atlantic at Moneypoint

2.2.7 Dispatch balancing costs of renewable constraint

As described in Section 2.2.2 above, we have optimised the re-dispatch of plant to replace the renewable generation turned-down as constraint in the Accelerated Decarbonisation Pathway. Under the I-SEM balancing market rules, plant that are turned-up to replace constrained renewable generation are paid the greater of their SRMC and the imbalance price.

We have used the results of this analysis, and our commodity and carbon price assumptions as detailed in Section 2.1.2, to calculate the incremental fossil gas and carbon costs associated with re-dispatching plant in these actions.

We have estimated the equivalent dispatch balancing cost in the SOEF Baseline using the benchmarking results of the network-level model detailed in Section 3.2.1, to determine the relativity of this cost between the Pathway and Baseline.

The potential upside currently paid to generators during periods of high imbalance price, and therefore increased cost burden on end consumers, has not been quantified.

2.2.8 Wholesale market 'cost to load'

The total cost of electricity purchased in the day-ahead market to meet demand (and paid to generators), or 'cost to load', is ultimately passed on to end consumers in Ireland and Northern Ireland. This cost component has been calculated in the Accelerated Decarbonisation Pathway relative to the Baseline using the hourly demand, net of demand from storage assets, and the day-ahead power price in I-SEM.

The deployment of incremental renewable capacity in the Pathway over the Baseline acts to decrease the day-ahead price during hours of their zero-marginal cost generation, providing a net benefit to end consumers.

2.2.9 Capacity market procurement costs

As discussed in Section 2.1.4 above, we have modelled the all-island CRM to ensure a DRCM of around 4%. Although wind and solar assets are not assumed to participate in the CRM directly[46], their assigned de-rating factors mean that they act to reduce the total fossil gas-fired capacity required in each auction. A net increase in assumed wind and solar capacity in the Accelerated Decarbonisation Pathway relative to the Baseline therefore reduces the CRM requirement, reducing any cost of the mechanism incurred by end consumers. We have calculated the net contribution of incremental wind and solar capacity in the Pathway relative to the Baseline, assuming de-rating factors from the *2024/25 T-3 Initial Auction Information Pack*[47]; around 9% and 13% for wind and solar PV respectively.

Similarly, energy storage assets are assigned de-rating factors based on their capacities and durations. The incremental build of 0.5-hour batteries in the Pathway relative to the Baseline therefore further reduces the cost of capacity provision. We have again aligned our de-rating factor assumptions with those of the 2024/25 T-3 auction, assuming an average export capacity of 20 MW.

[46] Although wind and solar assets backed by RESS subsidies can participate in the CRM, this is not mandatory and without incentive, as CRM revenues offset support payments.

[47] *IAIP2425T-3*

New-build fossil gas-fired plant are assumed to clear in CRM auctions at a price of 100 €/kW, de-rated, in both the Baseline and Pathway. Bid prices of this order, or greater, have secured contracts for fossil fuel-fired capacity in recent auctions, including the 2023/24 T-4[48] and the 2024/25 T-3[49]. Although the de-rated capacity contribution of wind and solar assets does not incur a cost to end consumers via the CRM, the incremental 0.5-hour duration batteries do require support payments from this mechanism under the assumptions of this study. We have assumed that these batteries act as price takers in the CRM, and on average receive the existing capacity price cap value of 46.15 €/kW, de-rated, offering a net saving to end consumers relative to procurement of new-build fossil gas-fired capacity. Different bidding behaviour of these batteries in the CRM would shift the cost of the assets incurred by end consumers between the components considered in Section 2.2.3, i.e., a contract price above 46.15 €/kW, de-rated, would reduce the net benefit described in this section, but decrease the net cost of procuring DS3 services, as detailed in Section 2.2.6.

The total cost of the all-island CRM is assumed to be divided between Ireland and Northern Ireland on a demand-weighted basis, in-line with current policy.

2.2.10 Dispatch balancing costs of DS3 limits

In our constrained market model run, the application of system-level DS3 limits forces the model to re-dispatch plant away from their ex-ante positions in the day-ahead schedule. These limits disfavour non-synchronous generators such as wind and solar plant and, in the absence of comprehensive zero-carbon system services, rely on fossil fuel-fired plant. This movement away from the marginal cost-based approach of the day-ahead schedule increases the total cost paid to generators to meet demand on the system. Under the I-SEM market arrangements, this cost is ultimately borne by end consumers as part of the 'imperfections charge' on electricity bills.

The net impact to this cost in the Accelerated Decarbonisation Pathway relative to the Baseline depends on the balance of installed renewable capacity, greater renewable penetration in the day-ahead schedule increases the associated dispatch balancing cost, and the relaxation of DS3 limits. We have divided any net cost or benefit between end consumers in Ireland and Northern Ireland on a demand-weighted basis, in accordance with current market arrangements.

[48] *FCAR2324T-4*
[49] *FCAR2425T-3*

2.3 Results and discussion

2.3.1 Annual system-level power sector CO_2 emissions

In 2020 a total of 8.4 million tonnes of CO_2 was emitted as a result of electricity generation in the Irish power sector, at an average emission intensity of 296 grams of CO_2 per kWh of generation (gCO_2/kWh)[50]. Preliminary analysis by the Environmental Protection Agency (EPA)[51] indicates that, due to increased demand and coal-fired generation, annual power sector emissions in Ireland increased by around 21% in 2021, to 10.2 million tonnes of CO_2.

These historical CO_2 emissions constitute almost a fifth of the indicative 55 $MtCO_2$ power sector carbon budget suggested for the decade, emitted within the first year.

Our Baseline and Pathways include a series of system-level interventions designed to reduce emissions from the Irish power sector, including:

- Continual roll-out of renewable generation capacity, supported by RESS contracts;
- Decommission of carbon intensive peat, coal, and oil-fired plant, as well as the retirement of older, less efficient fossil gas-fired plant; and
- The adoption of zero-carbon solutions to DS3 limits, reducing the reliance on re-dispatch of fossil fuel-fired plant.

In this section, we explore the impact of these measures on power sector emissions in Ireland, both from the position of plant in the day-ahead schedule, and after re-dispatch of plant to account for system-level DS3 limits. In Section 2.3.2 we then evaluate the cumulative system-level CO_2 emissions of each of our Pathways against those of the SOEF Baseline.

The impact of further re-dispatch of plant to account for network-level transmission constraints is not included in this section, instead being explored in Section 2.3.3 below, in which we layer on the associated CO_2 emissions from these actions in the SOEF Baseline and Accelerated Decarbonisation Pathway.

SOEF Baseline

Figure 13 below presents the annual CO_2 emissions from the Irish power sector in the SOEF Baseline, both at the day-ahead schedule, and the incremental emissions resulting from dispatch balancing to account for DS3 limits.

At the day-ahead schedule, in which plant are dispatched on a purely economic basis, annual CO_2 emissions decrease steadily over the first half of the decade from 9.0 $MtCO_2$ in 2022 to around 6.8 $MtCO_2$ in 2025, as older, more carbon intensive plant are replaced by fossil gas-fired plant backed by CRM contracts. A step change in emissions is seen in 2026, once the coal-fired Moneypoint plant is assumed to decommission (from April 2025), and 1 GW of offshore wind is deployed in Ireland. Day-ahead emissions continue to steadily decrease out to 2030, with around 2.1 $MtCO_2$ emitted in the final year of the modelled horizon.

[50] Energy in Ireland 2021

[51] Ireland's power generation and industrial emissions increase by 15 percent in 2021

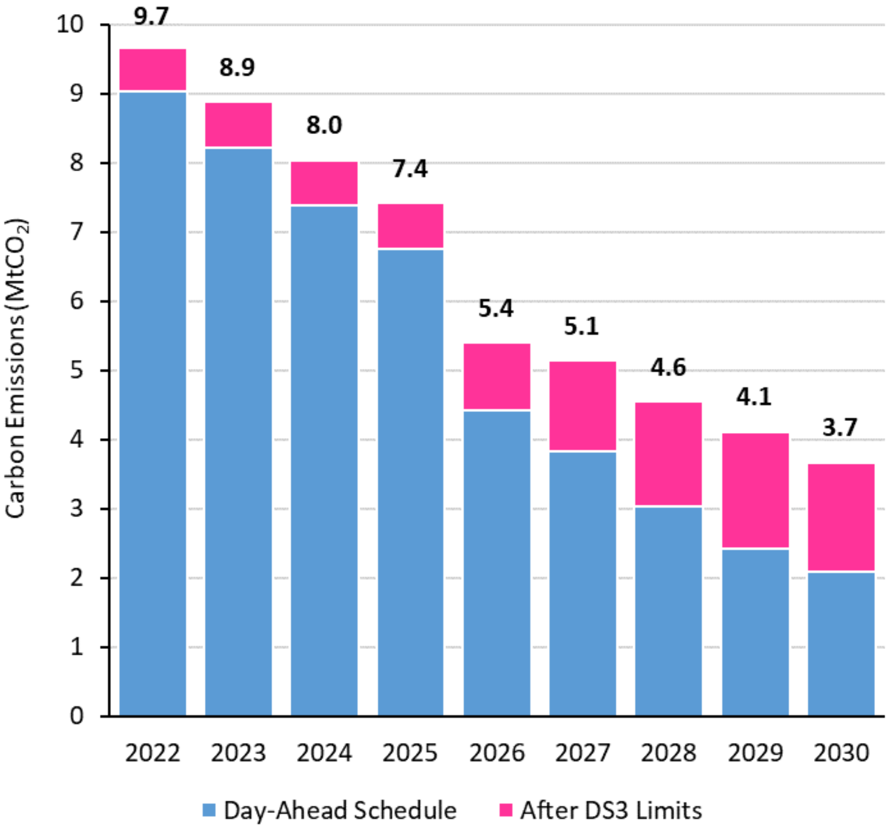
The optimistic *Shaping Roadmap* assumption of offshore wind capacity in Ireland from 2026, acts to artificially reduce Irish CO_2 emissions in the Baseline in 2026 and 2027, in which 1 and 2 GW are modelled respectively, relative to our Pathways that each assume deployment from 2028.

However, a quarter of the decrease in annual day-ahead emissions over the latter half of the decade is counteracted by increasing emissions resulting from dispatch balancing. As the penetration of renewable generation increases, driven primarily by the assumed growth in offshore wind, the incremental emissions resulting from dispatch balancing to maintain the SNSP, Min Gen, minimum inertia and RoCoF limits increase. By 2030, these incremental emissions reach 1.6 $MtCO_2$ annually, over 40% of the system-level total.

Between 2022 and 2030, annual system-level power sector CO_2 emissions in Ireland decrease by around 60%, with a 75% decrease achieved in day-ahead schedule emissions.

Irish power sector emissions in 2030, **before network-level constraint emissions are considered**, total around 3.7 $MtCO_2$, below the upper bound of the target presented in the *Climate Action Plan 2021*, but significantly above the more ambitious lower target of 2 $MtCO_2$.

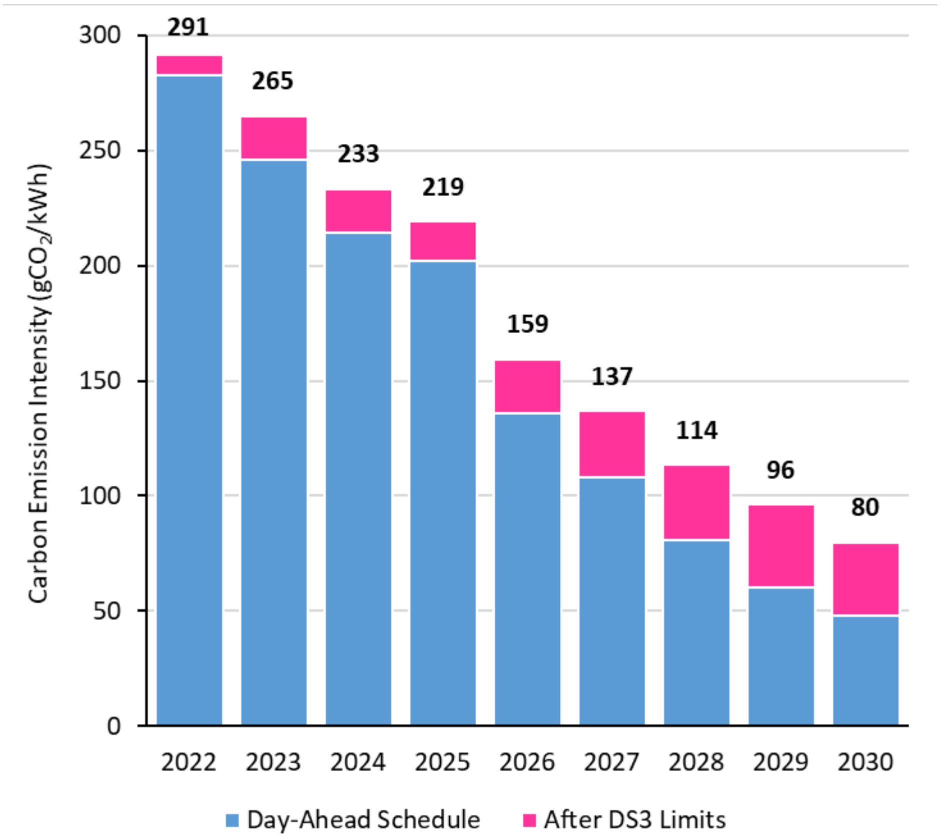
Figure 13: Annual system-level power sector CO_2 emissions in Ireland in the SOEF Baseline



In the Baseline, we have assumed a continual growth in electricity demand in Ireland, resulting in increasing upward pressure on CO_2 emissions. Figure 14 below presents the evolution of the emission intensity of generation in Ireland in the Baseline, evaluated before re-dispatch to account for transmission constraints.

The average emission intensity of Irish generation decreases from around 290 gCO_2/kWh in 2022, to 220 gCO_2/kWh in 2025, and 80 gCO_2/kWh in 2030 following the deployment of 5 GW of offshore wind. As with the absolute emissions, a greater decrease in emission intensity is seen at the day-ahead stage; an 80% decrease from 280 gCO_2/kWh in 2022 to 50 gCO_2/kWh in 2030.

Figure 14: Annual system-level power sector emission intensity in Ireland in the SOEF Baseline



Rapid Delivery and Delayed Delivery

Figure 15 and Figure 16 below present the annual Irish power sector CO_2 emissions in the Rapid Delivery and Delayed Delivery Pathways respectively. As described in Section 2.1.6, these Pathways explore the impact of deployment of equal capacities of wind and solar generation technologies by the end of 2030, with differing schedules.

Emissions from the ex-ante positions of plant in the day-ahead schedule in Ireland decrease at a greater rate in the Rapid Delivery Pathway than in the SOEF Baseline over the first half of the modelled horizon, reaching 5.4 $MtCO_2$ by 2025. In this Pathway, the procurement of onshore wind and solar PV capacity via the RESS auctions allows greater displacement of fossil fuel-fired generation from the day-ahead schedule. Correspondingly, the slower roll-out of wind and solar capacity in the Delayed Delivery Pathway results in an approximate parity between day-ahead emissions between it and the SOEF Baseline over this period, with around 6.9 $MtCO_2$ emitted in 2025.

By 2030, the deployment of incremental onshore wind and solar PV capacity above that assumed in the SOEF Baseline results in decreased day-ahead schedule emissions in both Pathways; 1.8 $MtCO_2$ in Rapid Delivery, and 2.0 $MtCO_2$ in Delayed Delivery respectively.

Figure 15: Annual system-level power sector CO_2 emissions in Ireland in Rapid Delivery

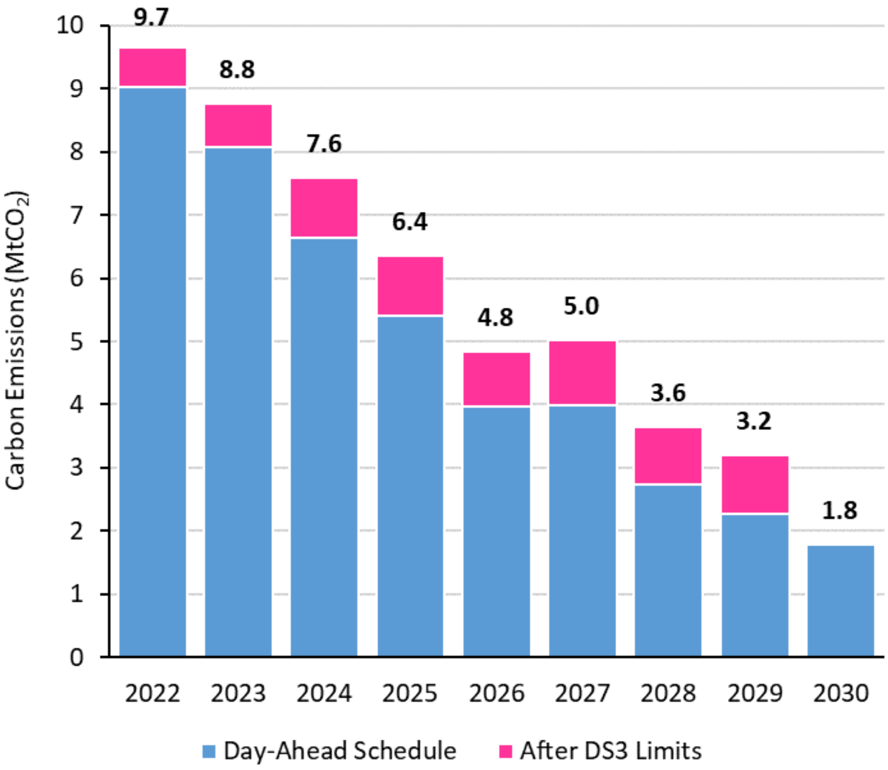
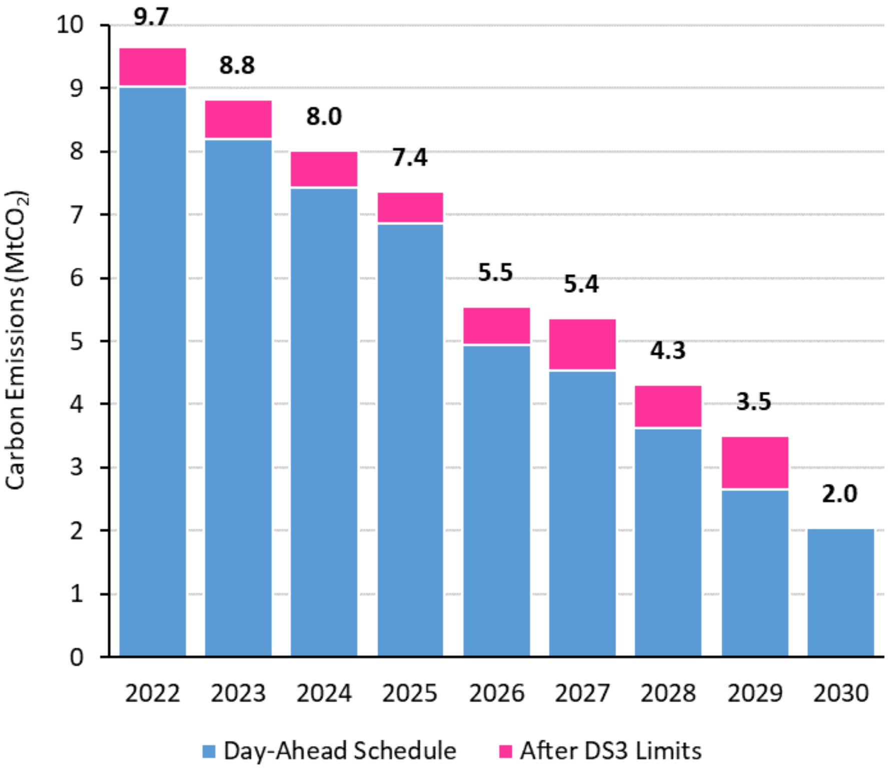


Figure 16: Annual system-level power sector CO_2 emissions in Ireland in Delayed Delivery



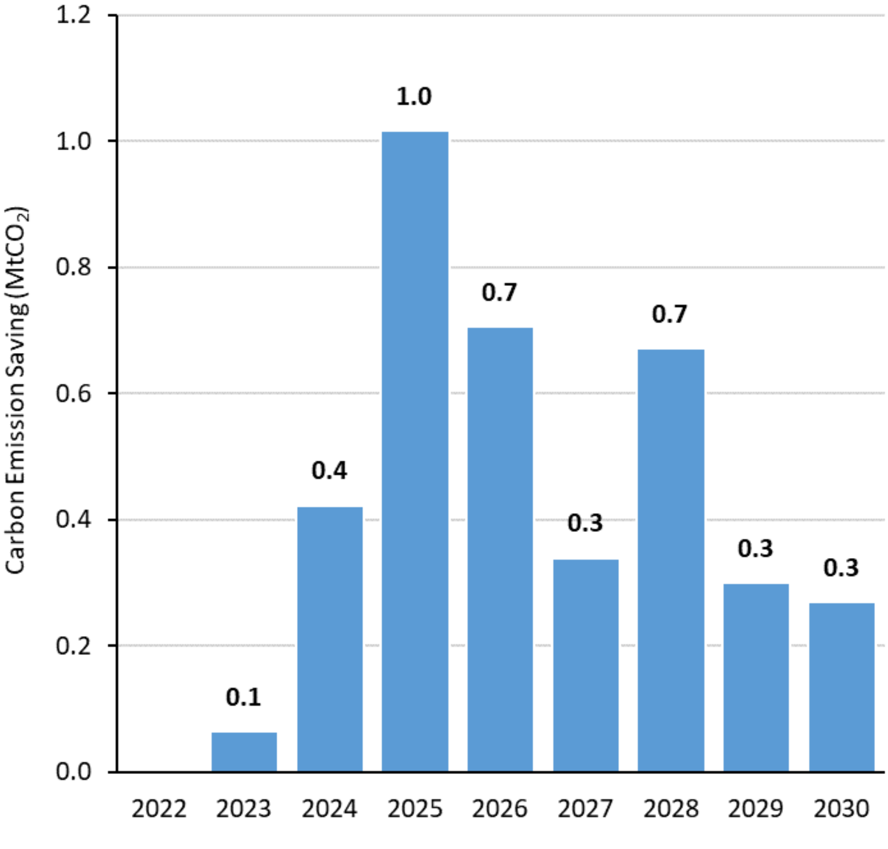
The displaced power sector emissions in the Rapid Delivery Pathway relative to Delayed Delivery, enabled by the faster deployment of renewable capacity backed by RESS contracts, is presented in Figure 17 below.

Although emissions in the day-ahead schedule in Rapid Delivery are decreased in-line with the rate of renewable capacity deployment, by around 5.5 $MtCO_2$ between 2021 and 2030, emissions from re-dispatch to maintain DS3 limits are increased by around 1.5 $MtCO_2$, eroding some of the benefit of more rapid wind and solar capacity deployment.

Emissions resulting from system-level dispatch balancing remain below those of the SOEF Baseline on average in both Pathways despite the greater assumed renewable penetration, due to the greater assumed adoption of zero-carbon system services, which enable the system to operate without such re-dispatch in 2030.

Before network constraints are considered, power sector emissions in Ireland in 2030 total 1.8 $MtCO_2$ in Rapid Delivery, and 2.0 $MtCO_2$ in Delayed Delivery, each below the 3.7 $MtCO_2$ projected in the SOEF Baseline, and below the *Climate Action Plan 2021* lower target of 2 $MtCO_2$ in the former.

Figure 17: Avoided Irish system-level CO_2 emissions in Rapid Delivery relative to Delayed Delivery



The corresponding average emission intensities of Irish generation in the Rapid Delivery and Delayed Delivery Pathways are presented in Figure 18 and Figure 19 below respectively. In the former Pathway, emission intensities decrease by over 85% from 2022 to 2030, reaching around 40 gCO_2/kWh by the end of the horizon.

Figure 18: Annual system-level power sector emission intensity in Ireland in Rapid Delivery

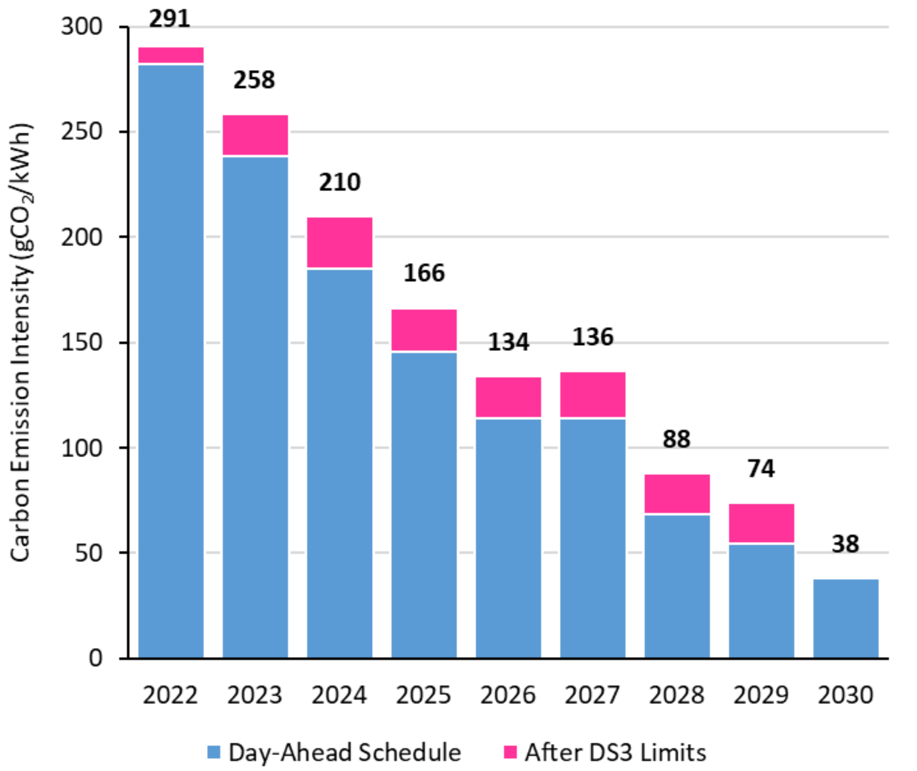
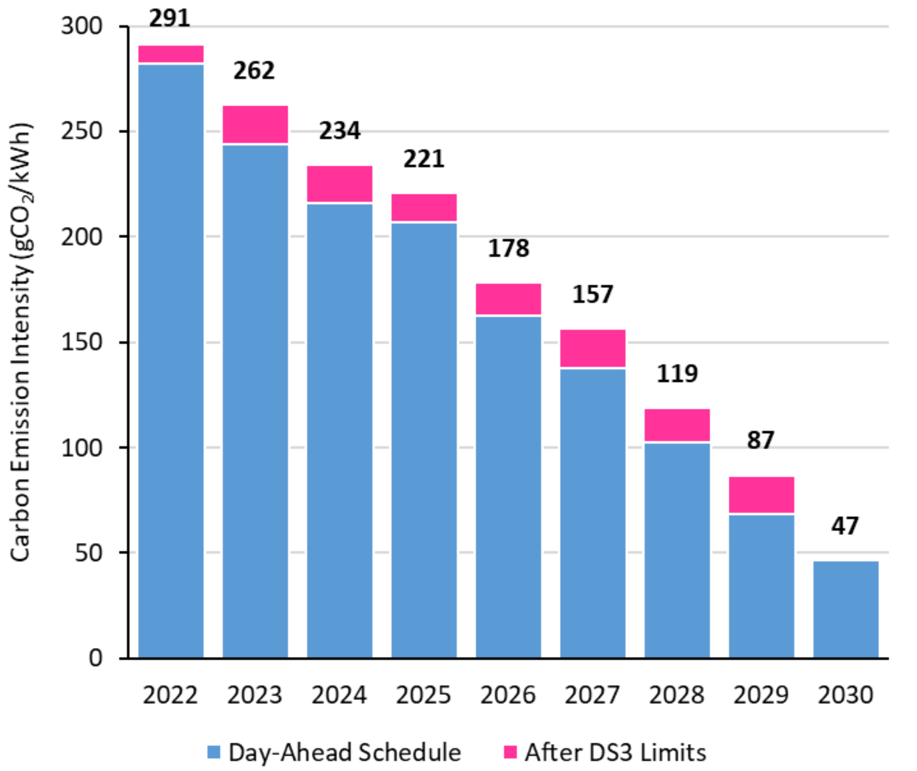


Figure 19: Annual system-level power sector emission intensity in Ireland in Delayed Delivery



Accelerated Decarbonisation

The system-level power sector emissions, and average emission intensity of generation, of our final Pathway, in which 8.2 GW of onshore wind, 5 GW of offshore wind, and 3 GW of solar PV are delivered in Ireland by the end of 2030, are presented in Figure 20 and Figure 21 below respectively. The increased capacity of onshore wind procured via RESS auctions results in the greatest overall reduction in system-level CO_2 emissions of our modelled Pathways.

A total of 1.6 $MtCO_2$ is emitted from the Irish power sector in 2030, a reduction of around 85% from 2022, and 55% below the 2030 system-level emissions of the SOEF Baseline. The emission intensity of generation decreases by around 90% over the modelled horizon.

At the system level, this Pathway achieves the 2 $MtCO_2$ targeted in 2030 as the most ambitious end of the emission range in the *Climate Action Plan 2021*. However, dispatch balancing at the network level to maintain transmission constraints results in further emissions, as are quantified in Section 2.3.3.

Figure 20: Annual system-level power sector emissions in Ireland in Accelerated Decarbonisation

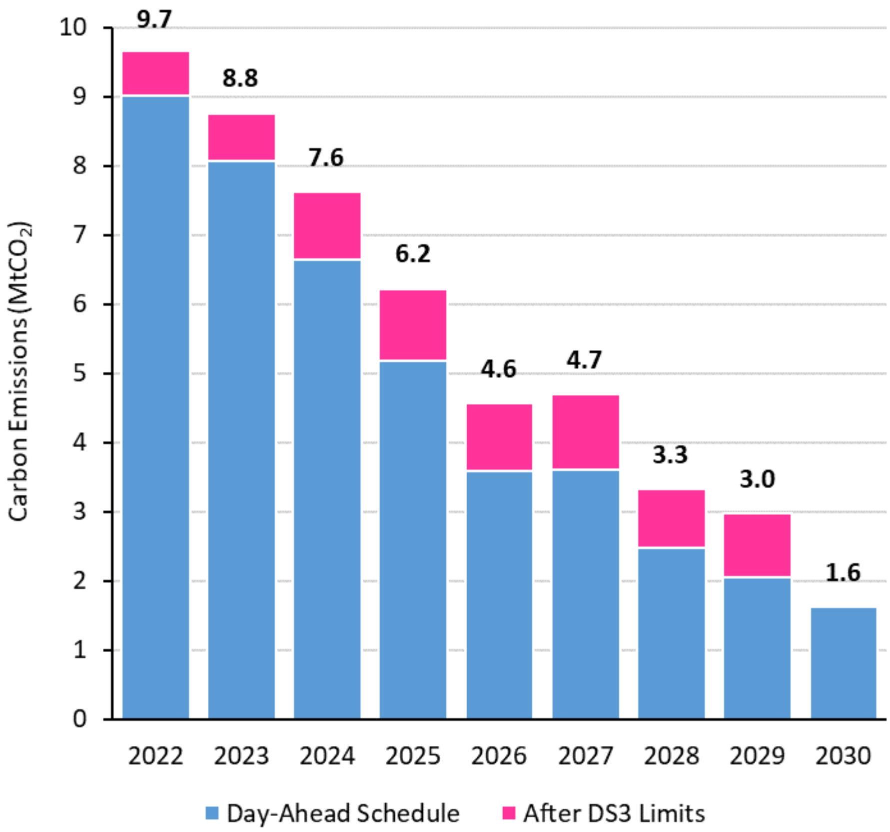
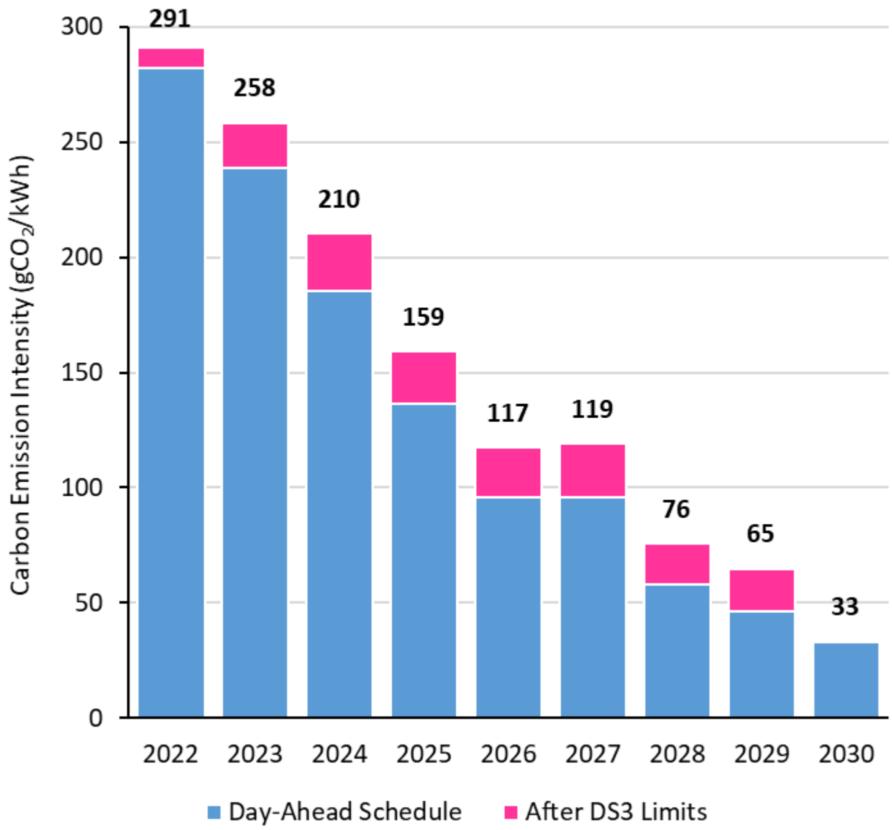


Figure 21: Annual system-level emission intensity in Ireland in Accelerated Decarbonisation



2.3.2 Cumulative system-level power sector CO_2 emissions

As discussed in Section 2.3.1, the 2030 system-level CO_2 emissions in the Baseline and each Pathway are complaint with the range targeted in the *Climate Action Plan 2021*, with the Pathways achieving the more ambitious lower bound of this range.

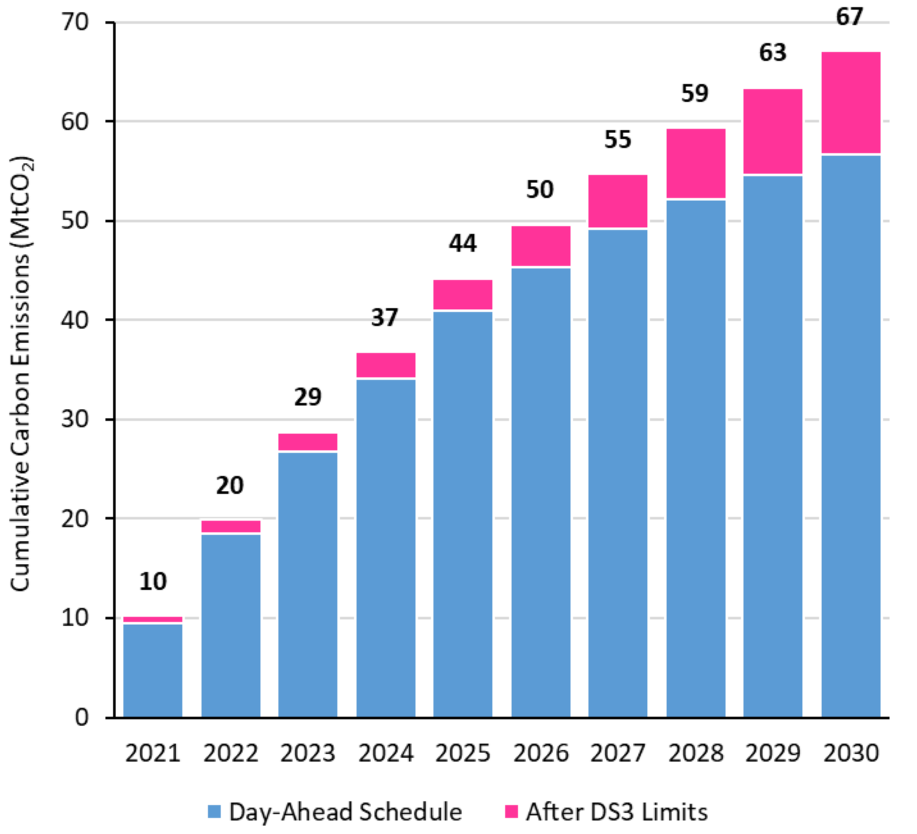
Despite the overall reductions in annual power sector emissions achieved in the Pathways, generation from coal, oil, peat, and inefficient fossil gas-fired assets results in relatively small emission reductions over the first half of the modelled horizon in each Pathway.

SOEF Baseline

The cumulative system-level CO_2 emissions from the Irish power sector in the SOEF Baseline are presented in Figure 22 below. Around 57 $MtCO_2$ is emitted from the day-ahead position of plant between 2021 and 2030 in the Baseline, before any re-dispatch to account for DS3 limits or transmission constraints. A further 10 $MtCO_2$ is emitted as a result of system-level DS3 limits.

Around two-thirds of the total system-level emissions are produced over the first half of the decade, around 44 $MtCO_2$, compared to 23 $MtCO_2$ emitted between 2026 and 2030. Although emissions from the day-ahead schedule decrease significantly over the horizon, the cumulative emissions resulting from DS3 limits increase in-line with the renewable penetration on the system; around 7 $MtCO_2$ in the second half of the decade, up from around 3 $MtCO_2$ in the first five years.

Figure 22: Cumulative power sector CO_2 emissions in Ireland in the SOEF Baseline[52]



Rapid Delivery and Delayed Delivery

Figure 23 and Figure 24 below present the cumulative system-level CO_2 emissions from the Irish power sector in the Rapid Delivery and Delayed Delivery Pathways respectively. The accelerated deployment of RESS-backed renewable capacity in Rapid Delivery avoids around 6 $MtCO_2$ from the Irish day-ahead schedule compared to that of Delayed Delivery, with around 53 $MtCO_2$ emitted from the former, and 59 $MtCO_2$ from the latter. However, the increased renewable penetration through the modelled horizon results in greater incremental emissions from re-dispatch of fossil fuel-fired plant in the more ambitious Pathway, around 8 $MtCO_2$ emitted in Ireland compared to 6 $MtCO_2$ in Delayed Delivery. A faster roll-out of technologies able to provide zero-carbon system services therefore offers the potential to decrease cumulative emissions further if their deployment can keep pace with the deployment of renewables.

In comparison to the SOEF Baseline, a greater capacity of delivered wind and solar technologies in the Rapid Delivery Pathway enables reduced day-ahead emissions. However, despite the deeper decarbonisation achieved by 2030 in the Delayed Delivery Pathway, cumulative day-ahead emissions in the SOEF Baseline remain lower, owing to the assumed linear deployment of offshore wind from 2026. Incremental emissions from DS3 limits are reduced relative to the Baseline in both Pathways despite higher renewable penetration, due to the increased adoption of zero-carbon system services.

[52] The division of the 10.2 $MtCO_2$ emitted in 2021 between day-ahead schedule emissions, and those from dispatch balancing, has been assumed to be equal to that projected in 2022.

Figure 23: Cumulative power sector CO_2 emissions in Ireland in Rapid Delivery

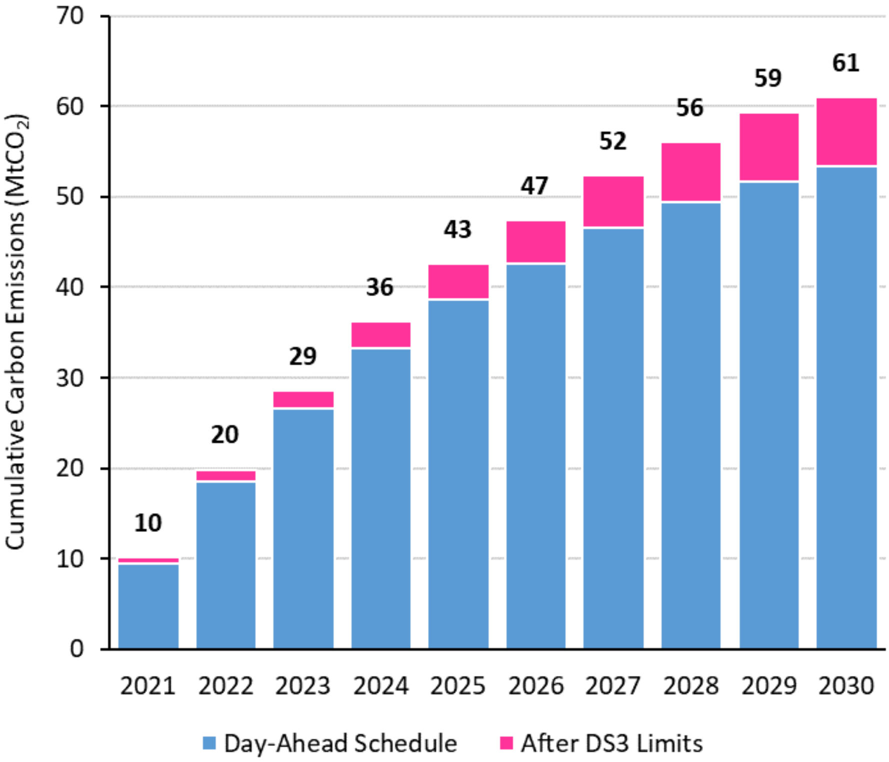
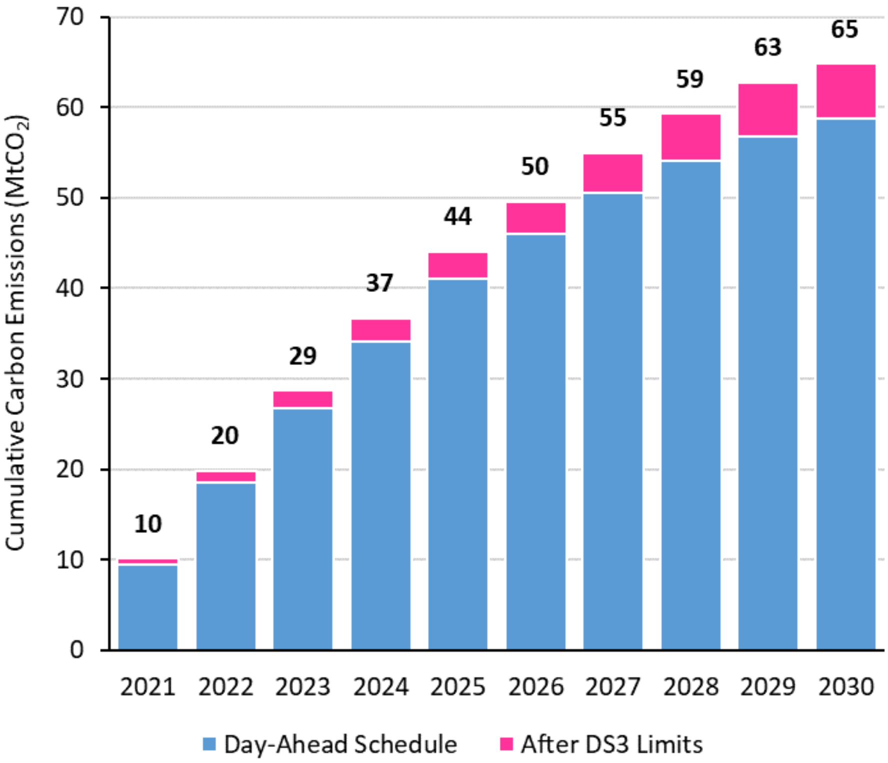


Figure 24: Cumulative power sector CO_2 emissions in Ireland in Delayed Delivery



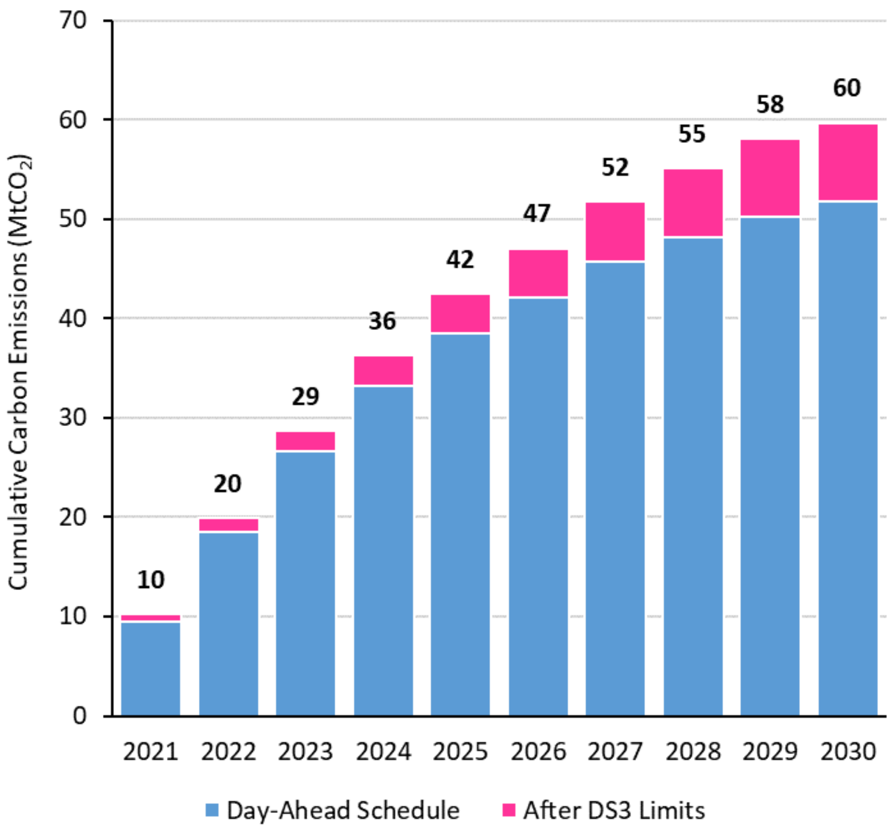
Accelerated Decarbonisation

Figure 25 below presents the cumulative Irish system-level emissions in the Accelerated Decarbonisation Pathway.

Increased procurement of onshore wind via RESS auctions in this Pathways results in the greatest degree of cumulative decarbonisation of our modelled Pathways, with a total of 60 $MtCO_2$ emitted between 2021 and 2030 in Ireland at the system level; around 52 $MtCO_2$ from the day-ahead positions of plant, and a further 8 $MtCO_2$ from re-dispatch of plant to maintain DS3 limits.

The 60 million tonnes of CO_2 quantified here do not include any incremental emissions from the further re-dispatch of plant to account for transmission constraints. We have quantified these incremental emissions, and present them in Section 2.3.3 below.

Figure 25: Cumulative power sector CO_2 emissions in Ireland in Accelerated Decarbonisation



2.3.3 Network-level dispatch balancing CO_2 emissions

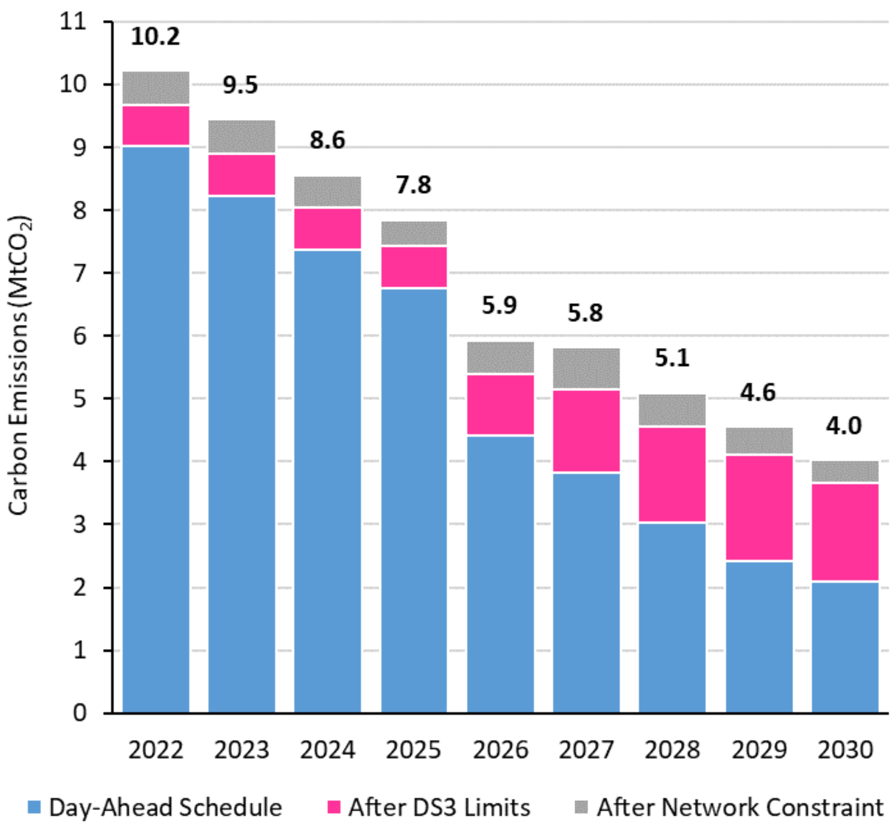
Throughout our system-level modelling, the I-SEM has been treated as a 'copper plate' system, in which power can flow freely from generation sites to regions of demand. In reality, the circuits of the transmission network in Ireland each have limits, and these transmission constraints often result in renewable generation being turned down to avoid overloading the circuits. Constrained generation must be replaced by dispatchable generation elsewhere on the network, resulting in increased emissions. The incremental emissions associated with this re-dispatch have been calculated as described in Section 2.2.2 above, based on the output of the modelling detailed in Section 3.

SOEF Baseline

Figure 26 below presents the total annual Irish power sector CO_2 emissions in the SOEF Baseline. Turn-up of fossil gas-fired plant to replace renewable generation turned-down as constraint results in an additional 0.6 $MtCO_2$ in 2022. As network reinforcement proceeds, without significant growth in renewable penetration, these incremental emissions fall to around 0.4 $MtCO_2$ in 2025. From 2026 onwards, once offshore wind begins to commission, emissions associated with constraint increase to around 0.7 $MtCO_2$ in 2027. Turn-up of batteries in the final years of the horizon acts to reduce this to around 0.3 $MtCO_2$ by 2030.

In aggregate, a total of 4.0 $MtCO_2$ is emitted from the Irish power sector in 2030, an approximately 60% decrease from the 10.2 $MtCO_2$ emitted in 2022.

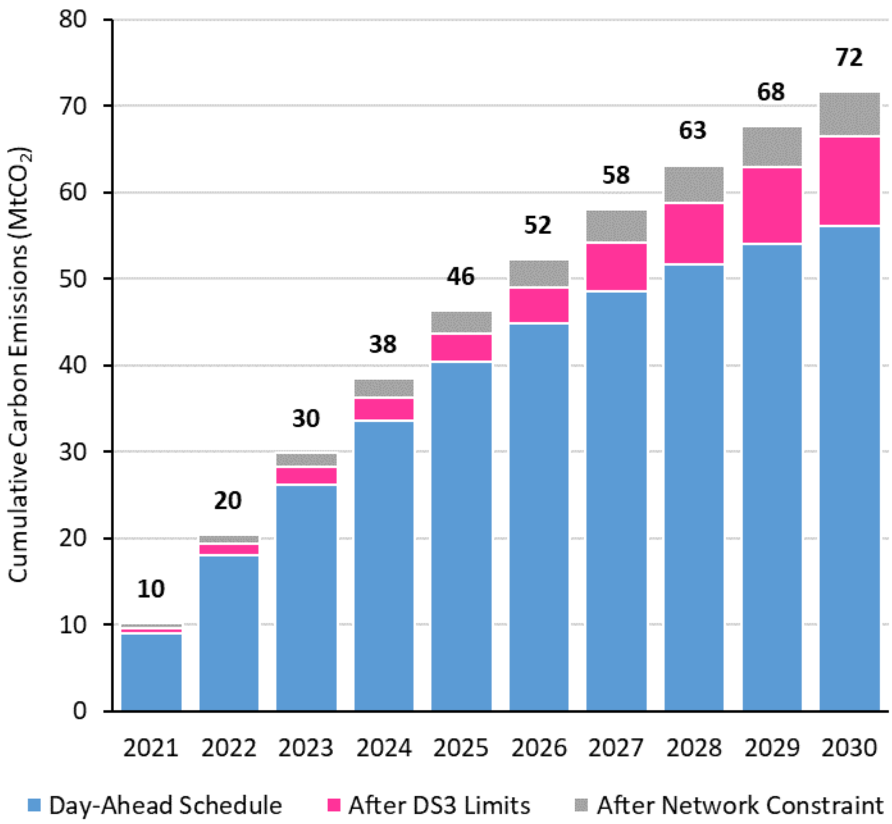
Figure 26: Annual total power sector CO_2 emissions in Ireland in the SOEF Baseline



A total of around 5 $MtCO_2$ is emitted to replace constrained renewable generation between 2021 and 2030 in the SOEF Baseline, as shown in Figure 27 below. Network solutions keep overall pace with the build-out of renewable capacity, with roughly equal volumes of CO_2 emitted in each half of the decade.

After dispatch balancing actions are considered, a total of 72 $MtCO_2$ is emitted from the Irish power sector between 2021 and 2030. Power sector emissions total 46 $MtCO_2$ in the 2021-2025 period, around 16% of the national carbon budget, and 25 $MtCO_2$ between 2026-2030, around 13% of the overall Irish budget.

Figure 27: Cumulative total power sector CO_2 emissions in Ireland in the SOEF Baseline



Accelerated Decarbonisation

As is presented in Figure 28 below, the increased renewable penetration in Ireland in the Accelerated Decarbonisation Pathway results in greater incremental emissions from constraint of renewables, despite the complementary network development detailed in Section 3.3.

Delivery of wind and solar capacity backed by RESS 2 and RESS 3 contracts acts to increase incremental emissions to a peak of around 1.0 $MtCO_2$ in 2025. A combination of network reinforcement and increased battery re-dispatch gradually decreases annual incremental emissions to around 0.4 $MtCO_2$ by 2030.

Total power sector emissions decrease from 10.2 $MtCO_2$ in 2022, which represents a negligible change to 2021 power sector emissions, to 2.0 $MtCO_2$ by 2030, the most decarbonised end of the range targeted in the *Climate Action Plan 2021*.

Figure 28: Annual total power sector CO_2 emissions in Ireland in Accelerated Decarbonisation

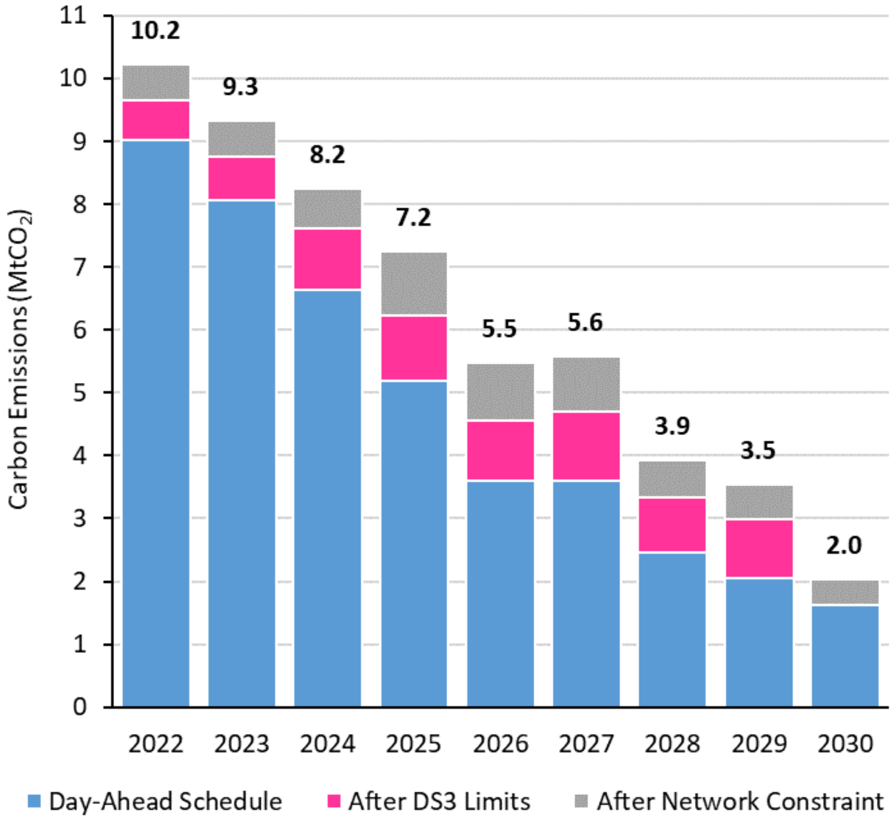
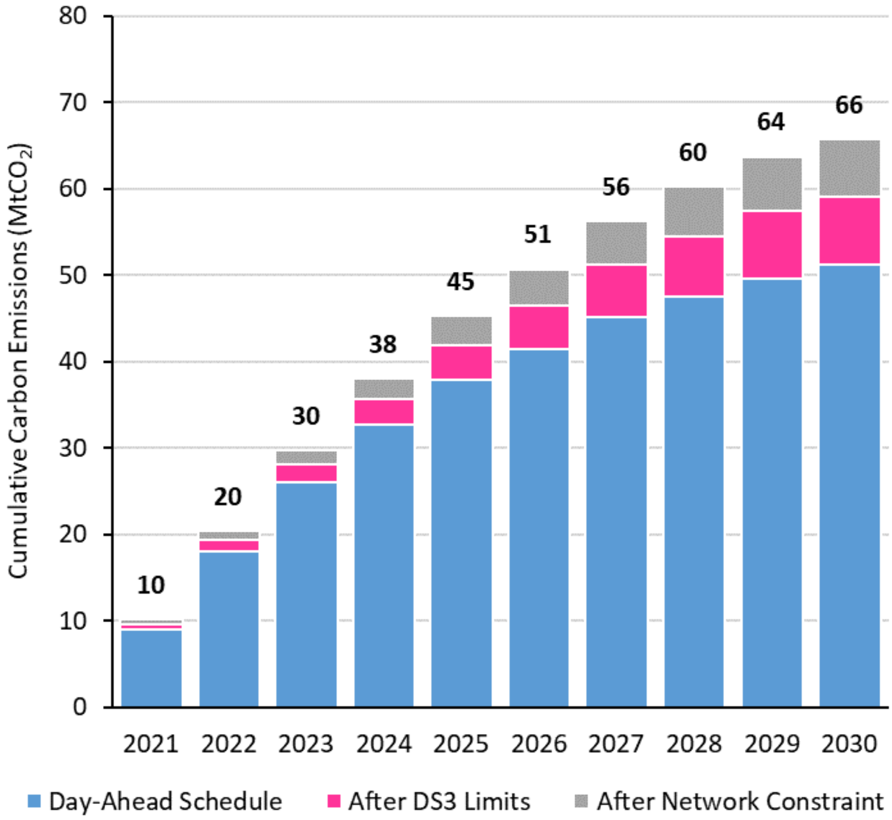


Figure 29 below presents the CO_2 emissions of the Accelerated Decarbonisation Pathway on a cumulative basis. Greater ambition with respect to wind and solar capacity deployment, zero-carbon system services, and network development, leads to a saving of 6 $MtCO_2$ relative to the SOEF Baseline, with 66 $MtCO_2$ emitted in Ireland between 2021 and 2030. Avoided CO_2 emissions relative to the Baseline equate to three times the 2030 Irish power sector emissions in this Pathway.

A total of 45 $MtCO_2$ is emitted in the 2021-2025 period, with around 21 $MtCO_2$ emitted between 2026-2030. This represents decreases of around 1 and 5 $MtCO_2$ relative to the SOEF Baseline in the first and second halves of the decade respectively. 15% and 10% of the national 5-year carbon budgets is emitted by the Irish power sector in the first and second halves of the decade respectively.

In total, 52 $MtCO_2$ is emitted from the day-ahead position of plant between 2021 and 2030, with 8 $MtCO_2$ emitted during re-dispatch to maintain DS3 limits, and 6 $MtCO_2$ emitted during network-level dispatch balancing.

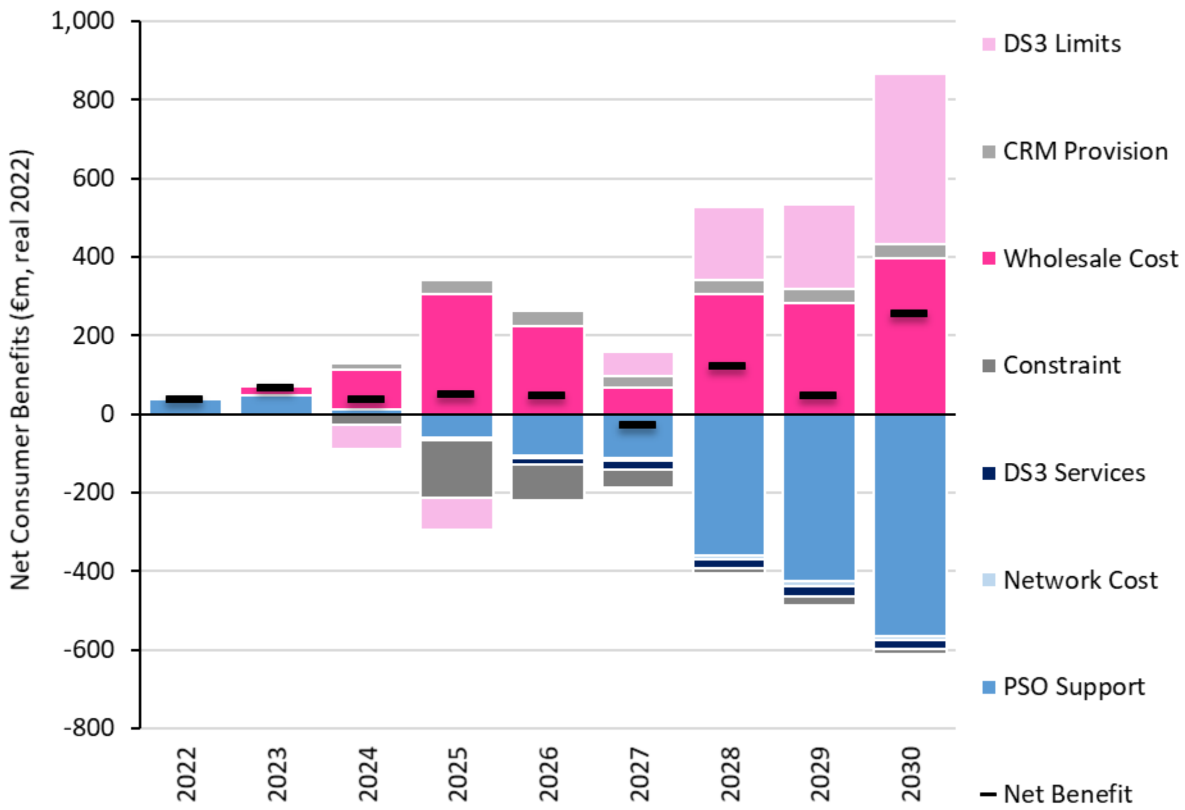
Figure 29: Cumulative total power sector CO_2 emissions in Ireland in Accelerated Decarbonisation



2.3.4 End consumer cost-benefit analysis

We have evaluated the net costs and benefits to end consumers in Ireland offered by the Accelerated Decarbonisation Pathway relative to the SOEF Baseline, using the methodologies detailed throughout Section 2.2. The results of this comprehensive analysis are presented in Figure 30 below, in which net benefits are presented as positive, and net costs presented as negative.

Figure 30: Irish end consumer cost-benefit analysis of Accelerated Decarbonisation relative to SOEF



The Accelerated Decarbonisation Pathway results in a net saving to end consumers in Ireland of over €600m between 2022 and 2030, comprised of the following costs and benefits, each of which have been evaluated relative to the SOEF Baseline:

- **DS3 limit costs**: The cost associated with dispatch balancing of plant to maintain system-level DS3 limits in the Baseline and Pathway reflects the balance of renewable penetration in the day-ahead schedule, against the unwinding of the limits enabled by zero-carbon system services. In the Accelerated Decarbonisation Pathway, the increased renewable capacity results in a net cost to end consumers relative to the SOEF Baseline, which increases to around €80m per year by 2025. From 2026 to 2030, the increased adoption of zero-carbon solutions to DS3 limits reduces the need to re-dispatch plant in the Pathway relative to the Baseline, despite greater installed renewable capacity, and offers a net benefit to end consumers. By 2030, this benefit reaches around €440m in Ireland per year. This latter effect, which only manifests once progress is made with respect to DS3 limits, dominates, with a total net saving of around €750m afforded to end consumers between 2022 and 2030. The size of this net benefit relative to the Baseline; being larger in 2030 than the savings brought by depression of wholesale prices, is indicative of the value offered by zero-carbon system services in Ireland. This value is many times greater than the fundamental cost of the providing technologies, and increases with the penetration of renewable generation, and the cost of fossil fuel-fired generation.

- **CRM procurement costs**: The incremental build-out of wind and solar capacity in the Pathway brings an additional net benefit to end consumers in Ireland by contributing towards the DRCM of the system, and reducing the need to procure new-build fossil gas-fired assets in the CRM. Similarly, the incremental battery capacity brings further net benefit in the CRM, and in total, the renewable and storage assets are able to reduce end consumer costs by around €35m per year by the second half of the decade. Over the modelled horizon, a net saving in the CRM of around €240m is passed on to end consumers in Ireland.
- **Wholesale 'cost to load'**: From 2022 to 2025, the incremental onshore wind and solar PV capacity increases relative to the SOEF Baseline. By bidding into the day-ahead wholesale market at 0 €/MWh, these assets decrease the average wholesale price, and therefore reduce the total cost incurred by end consumers to meet demand in the day-ahead market by around €310m in 2025. As offshore wind capacity is assumed to commission in the Baseline from 2026, the relative benefit brought by renewables in the Pathway decreases, to around €70m in 2027. This effect represents an artificial reduction of costs in the Baseline, enabled by the optimistic deployment of offshore wind from 2026. This trend is then reversed once offshore wind is commissioned in the Pathway from 2028; a benefit of around €400m is provided to Irish end consumers in 2030. A total cost saving of around €1,700m is provided to end consumers by this effect between 2022 and 2030, the largest net benefit offered by the Pathway.
- **Constraint costs**: The increased renewable penetration in the Accelerated Decarbonisation Pathway over the SOEF Baseline results in greater renewable constraint volumes across the horizon. The net cost relative to the SOEF Baseline of turning-up more fossil gas-fired assets, and therefore burning more fossil gas and emitting more CO_2, increases out to around €150m annually by 2025. From 2026 out to 2030, this incremental cost over the Baseline decreases due to network development, and a greater supply of zero marginal-cost electricity for battery turn-up, in the Pathway. By 2030, this net cost constitutes around €15m to end consumers in Ireland. In aggregate, end consumers incur a net cost of around €360m from greater renewable constraint in the Pathway.
- **DS3 service costs**: The increased ambition towards zero-carbon solutions to system-level DS3 limits results in another net cost that increases throughout the horizon. As the incremental build of enabling assets; synchronous condensers and dedicated DS3-providing batteries, increases, so does the annuitized cost incurred by end consumers. By 2030, these assets bring an incremental cost of around €25m per year, totalling over €110m over the horizon. This figure represents the fundamental inherent cost of delivering the technologies, rather than the value they offer to the system and end consumers, this being captured as a net benefit within the relative 'DS3 limit costs'.
- **Network development costs**: The incremental development of the Irish network, necessitated by the need to integrate additional renewable capacity, brings a net cost to end consumers in each year. As the renewable penetration of the Pathway increases throughout the horizon, a series of network upgrades are required, each adding to the annuitized cost incurred by end consumers. By 2030, this annuitized net cost reaches around €10m annually. The extent of the network development assumed in the SOEF Baseline, and the regulated rate of return on network projects in Ireland, result in this being the smallest of the net cost components quantified in this analysis. A total net cost of around €50m is incurred by end consumers in Ireland between 2022 and 2030.

- **PSO support costs**: High commodity and carbon prices in the initial years, out to 2024, and the incremental deployment of wind and solar capacity results in a net benefit relative to the SOEF Baseline, as the two-way nature of the RESS CfD allows end consumers to receive the upside value of the scheme when the day-ahead revenue captured by renewable assets exceeds the strike price. From 2025 onwards, decreases in the wholesale power price, and further build-out of renewable assets, reduce captured prices below respective strike prices. This results in a net cost to consumers relative to the SOEF Baseline, which increases out to around €560m annually by 2030. Over the modelled horizon, the incremental cost incurred to consumers via the PSO levy totals around €1,500m; the largest net cost component of the Pathway.

2.3.5 Renewable electricity generation

In the *GCS 2021*, EirGrid and SONI define renewable electricity to include 100% of that generated by wind, solar, hydro, and biomass technologies, and 50% of generation from waste-to-energy plant. The proportion of demand met by these sources (RES-E) reached around 43%[53] in 2020, though this equates to around 39% once normalised[54], below the national target of 40%.

Figure 31 below presents the projected renewable electricity in Ireland in the SOEF Baseline. Between 2022 and 2025, growth of electricity demand in Ireland, in combination with the limited roll-out of wind and solar capacity in these years, results in the total proportion of demand met by renewables remaining flat at around 36%. The assumed linear growth of installed offshore wind capacity increases renewable electricity in proportion, reaching 74% by 2030, after network constraints have been accounted for.

Figure 32 below presents the equivalent RES-E metric for the Accelerated Decarbonisation Pathway. Commission of onshore wind and solar PV capacity backed by RESS 2, RESS 3, and RESS 4 contracts provides net growth in renewable electricity in 2024, 2025, and 2026 respectively, despite increasing Irish demand. After a pause in renewable capacity deployment in 2027, renewable electricity increases to 90% by 2030, once 5 GW of offshore wind capacity has commissioned, backed by support contracts tendered in the ORESS 1 and ORESS 2 auctions.

By 2030, around 45% of Irish demand is met by onshore wind, with 37% met by offshore wind, 6% met by solar PV, and 2% met by hydro, biomass-fired, and waste-to-energy generation.

[53] Electricity consumption from renewables 2020

[54] Generation from weather-dependant renewable sources such as wind, solar, and hydro plant, are typically 'normalised' in the presentation of annual RES-E figures to account for the volatility of weather between years. Normalised values represent the expected RES-E if that year had overall 'average weather'.

Figure 31: Proportion of demand met by renewables in Ireland in the SOEF Baseline

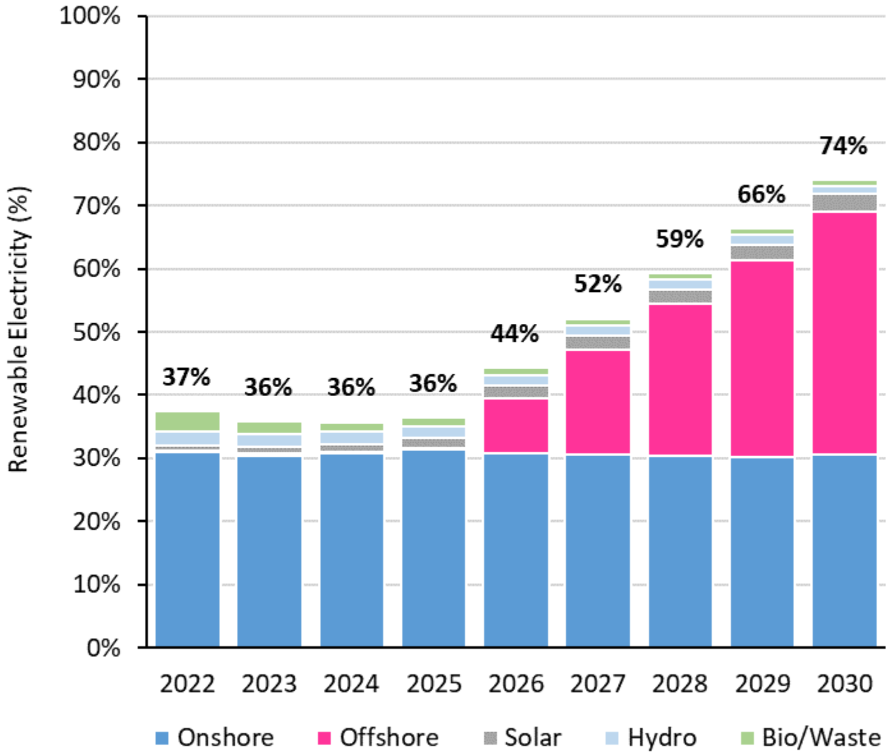
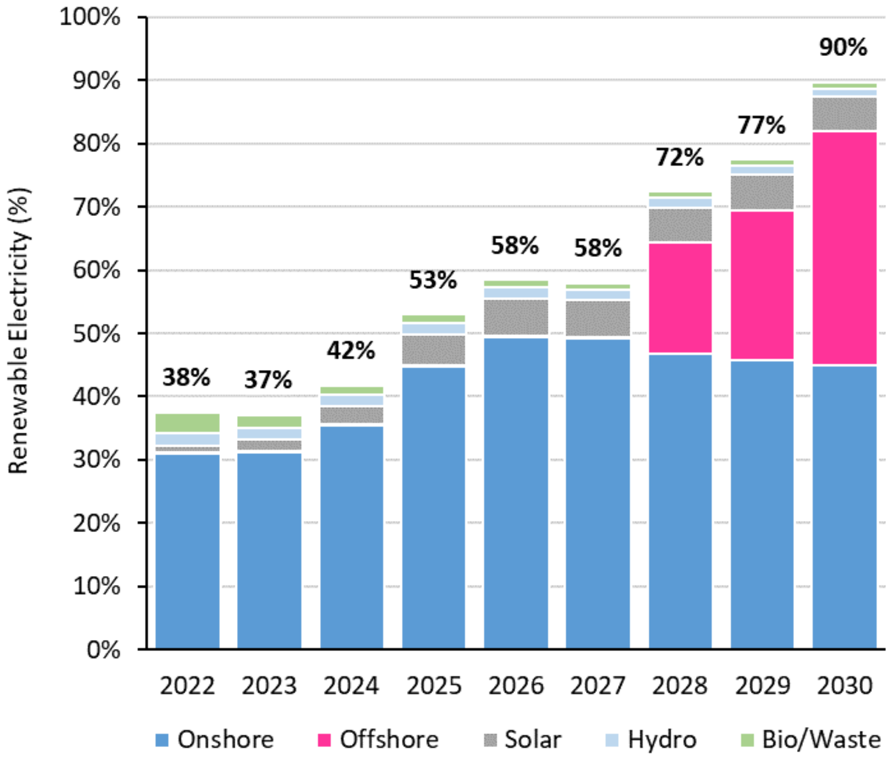


Figure 32: Proportion of demand met by renewables in Ireland in Accelerated Decarbonisation



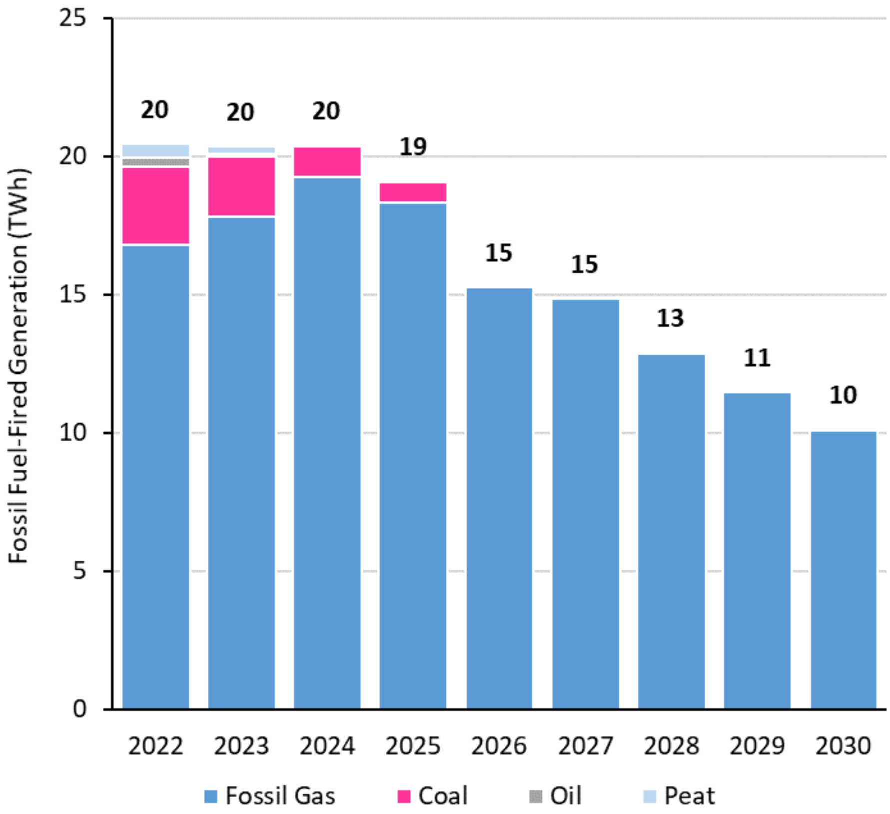
2.3.6 Fossil fuel-fired generation

Demand in the I-SEM system that is not met by the renewable sources explored in Section 2.3.5 above is met by a combination of fossil fuel-fired generation, and net imports from the neighbouring British and French markets, in both the SOEF Baseline and Accelerated Decarbonisation Pathway.

Figure 33 below presents the annual fossil fuel-fired generation in Ireland in the SOEF Baseline, including re-dispatch of plant to account for DS3 limits and transmission constraints. Fossil fuel-fired generation in Ireland remains flat at around 20 TWh per year in the Baseline until the commissioning of offshore wind from 2026 reduces it steadily to around 10 TWh in 2030. This represents around 20% of the total Irish demand in this modelled year.

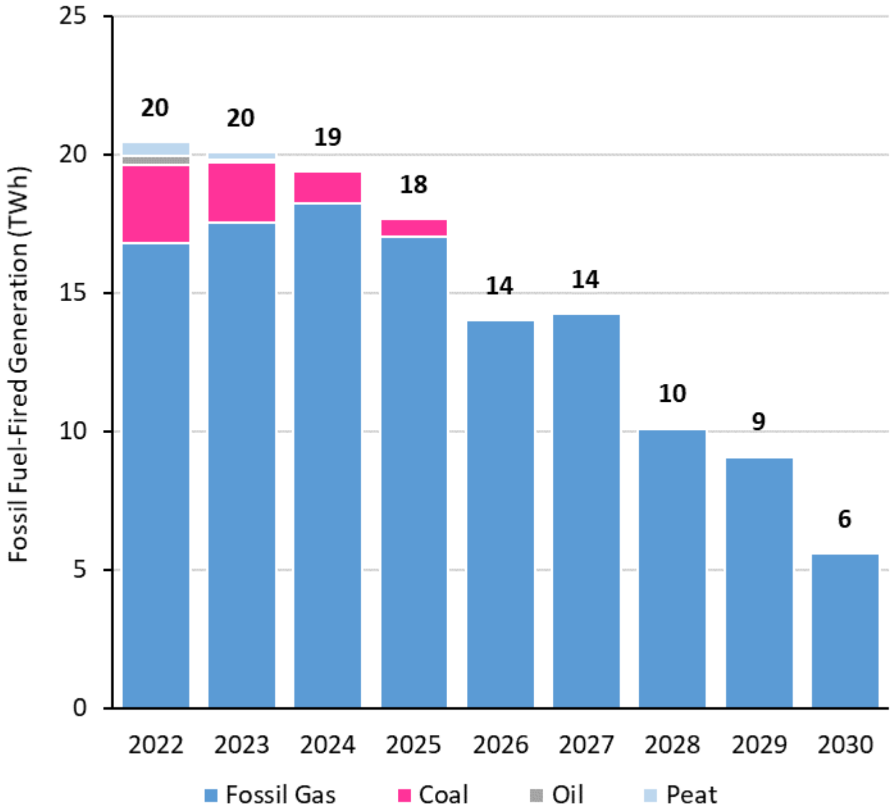
Generation from peat and coal-fired assets is phased out with the decommissioning, or conversion, of these generation technologies by 2024 and 2025 respectively. Despite the presence of oil-fired capacity in Ireland out to 2030, generation from these assets becomes negligible from 2024 onwards. Between 2022 and 2030, fossil fuels meet around 40% of the total Irish demand.

Figure 33: Fossil fuel-fired generation in Ireland in the SOEF Baseline



The residual fossil fuel-fired generation in Ireland in the Accelerated Decarbonisation Pathway is presented in Figure 34 below. Despite the increased need to turn-up these assets to replace constrained renewable generation, the increased capacity of wind and solar technologies throughout the horizon and the increased uptake of zero-carbon system services in the Pathway decrease fossil fuel-fired generation to around 6 TWh by 2030, around 10% of the Irish demand. Fossil fuel-fired assets meet around 35% of the electricity demand in Ireland between 2022 and 2030 in this Pathway.

Figure 34: Fossil fuel-fired generation in Ireland in Accelerated Decarbonisation



CO_2 emissions by generation technology

Despite contributing to around 94% of fossil fuel-fired generation in Ireland in the Accelerated Decarbonisation Pathway, use of fossil gas emits around 85% of the power sector CO_2 emissions between 2022 and 2030. As is presented in Figure 35 and Table 8 below, more carbon intensive fossil fuels contribute a disproportionate volume of CO_2 emissions while in use during the first half of the decade.

On a cumulative basis, between 2021[55] and 2030, Irish power sector emissions in the Accelerated Decarbonisation Pathway, including emissions associated with network constraint, result from technologies in the following proportions:

- Fossil gas-fired plant emit 54 $MtCO_2$, or 82% of the Irish total;
- Coal-fired plant emit 10 $MtCO_2$, or 15% of the Irish total;
- Oil-fired plant emit around 1 $MtCO_2$, or 1.5% of the Irish total; and
- Peat-fired plant emit around 1.5 $MtCO_2$, or 2% of the Irish total.

[55] Outturn CO_2 emissions in 2021 have been assumed result from generation technologies according to their ratios as projected in 2022.

Figure 35: Annual Irish power sector emissions by fossil fuel type in Accelerated Decarbonisation

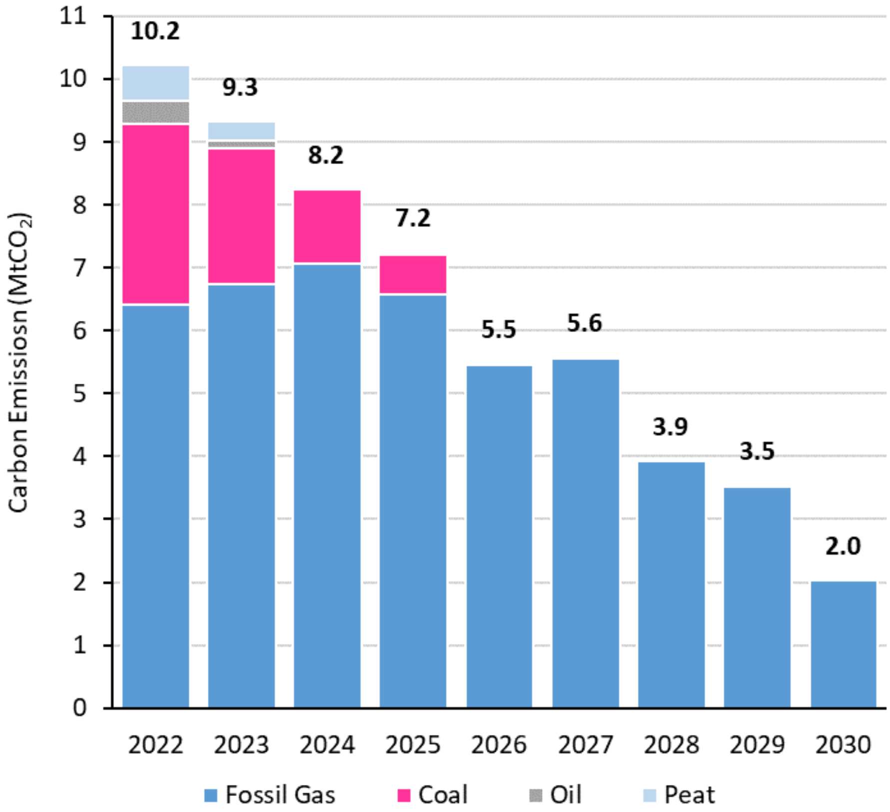


Table 8: Tabulated Irish power sector emissions by fossil fuel type in Accelerated Decarbonisation

Emissions by Fossil Fuel	Units	2022	2023	2024	2025	2026	2027	2028	2029	2030
Annual CO_2 Emissions										
Fossil gas	*$MtCO_2$*	6.4	6.7	7.1	6.6	5.5	5.6	3.9	3.5	2.0
Coal	*$MtCO_2$*	2.9	2.2	1.2	0.6	0.0	0.0	0.0	0.0	0.0
Oil	*$MtCO_2$*	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peat	*$MtCO_2$*	0.6	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative CO_2 Emissions										
Fossil gas	*$MtCO_2$*	12.8	19.6	26.6	33.2	38.7	44.2	48.2	51.7	53.7
Coal	*$MtCO_2$*	5.7	7.9	9.1	9.7	9.7	9.7	9.7	9.7	9.7
Oil	*$MtCO_2$*	0.7	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Peat	*$MtCO_2$*	1.1	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4

3 A Network Roadmap for Ireland

3.1 Our model and approach

In this study we have used TNEI's network-level model to conduct a detailed technical transmission network assessment of the Accelerated Decarbonisation Pathway. We have modelled the circuit-level flows based on the results of the first market model run, representative of the day-ahead schedule, to reflect the dispatch balancing of plant away from their ex-ante positions[56].

As discussed in Section 2.3, the Accelerated Decarbonisation Pathway provides the greatest opportunity of our Pathways to decarbonise the Irish power sector. Therefore, it also provides a glimpse into the regions of the transmission network that require development in order to enable a Net Zero power sector in Ireland. The objective of our network-level analysis is to identify the key transmission network development projects and technologies, over and above those assumed in the *Shaping our Electricity Roadmap*, required in a Network Roadmap to enable the Accelerated Decarbonisation Pathway, allowing the power system to operate with more than 80% renewable electricity by 2030 and achieve each of the power sector targets of the *Climate Action Plan 2021*.

In our network-level modelling exercise we have considered four individual spot years, in which we have simulated the Irish transmission network under the market model results of the Accelerated Decarbonisation Pathway:

- **2022**: The existing transmission network.
- **2025**: The addition of the outstanding[57] 110 kV Associated Transmission Reinforcement (ATR)[58] projects.
- **2027**: The impact of some significant ATR new-builds and the majority of the uprates considered in the *Shaping Roadmap*.
- **2030**: All projects included in the *Shaping Roadmap*, and those additionally required to enable the Accelerated Decarbonisation Pathway.

The analysis presented in this section consists of five parts:

- Network constraint analysis, as presented in detail in Section 2.2.2 above;
- Benchmarking against the *Shaping Roadmap*, presented in Section 3.2.1;
- Opportunity analysis for generation and storage technologies, presented in Sections 3.2.2 and 3.2.3 respectively;
- Impact of other new technologies, such as power flow control and dynamic line rating, presented in Section 3.2.4; and
- Transmission system needs assessment identification, presented throughout Section 3.3.

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[56] The hourly renewable constraint resulting from the network-level model has been adjusted to net off renewable curtailment in the analysis detailed in Section 2.2.2, to avoid double-counting in hours of system-level dispatch balancing.

[57] *Q1 2022 Associated Transmission Reinforcement (ATR) Status Update*

[58] The ATR projects are a series of transmission network reinforcements associated with generation projects to allow for firm access, many of which are expected to deliver in advance of the *Shaping Roadmap* projects.

The network-level model consists of an hourly AC power flow simulation of the market schedule output (for generation, interconnection, and demand) overlaid on a circuit-level representation of the all-island transmission network.

Data published alongside EirGrid and SONI's *All-Island Ten-Year Transmission Forecast Statement 2020*[59], pertaining to the years 2020 and 2029, was used as the basis for the circuit-level assumptions of the model. The all-island network, including both Ireland and Northern Ireland, was considered in the power flow simulations, overlaid with the standard N and N-1 contingencies typically applied in network-level analysis. The results of the analysis are presented in the remainder of this section, including a summary of the findings in the following key regions of the Irish network:

- North-West
- South-East
- Dublin
- South-West
- The Midlands

The power flow simulations identified a number of transmission network requirements, which include thermal overloading on circuits, and instances of low and high voltage at substations throughout the power system. Six distinct approaches were considered to address these requirements:

- **Network solutions**: The traditional approach to transmission network development that includes the deployment of new circuits and new transformers, as well as overhead line uprating, overhead line upvoltage and underground circuit replacement[60].
- **Cluster stations**: To avoid overloading the 110 kV network, the higher capacity 220 kV network can be used to group a number of renewable generation connections into a centralised location.
- **Dynamic line rating (DLR)**: Identifying overhead lines that will benefit from a capacity increase due to environmental factors such as variations in wind speed and ambient temperature. These factors can enhance the cooling effect on the overhead lines and will offer greater capacity on some circuits.
- **Energy storage**: Strategic deployment of energy storage technologies in constrained regions of the network to reduce constraint of renewable generation, by taking in excess generation during hours of constraint, and allows for additional renewable connections to be accommodated.
- **Power flow control**: Power sharing can be unbalanced in parts of the transmission network, particularly following outages. Power flow control technologies can force power into parts of the network with redundant capacity, by changing circuit impedance.
- **Reactive/synchronous power compensation**: As the power system moves towards the 80% renewable electricity targeted in the *Climate Action Plan 2021*, addressing DS3 limits, and ensuring dynamic voltage management will be one of the most significant challenges.

[59] *All-Island Ten-Year Transmission Forecast Statement 2020*

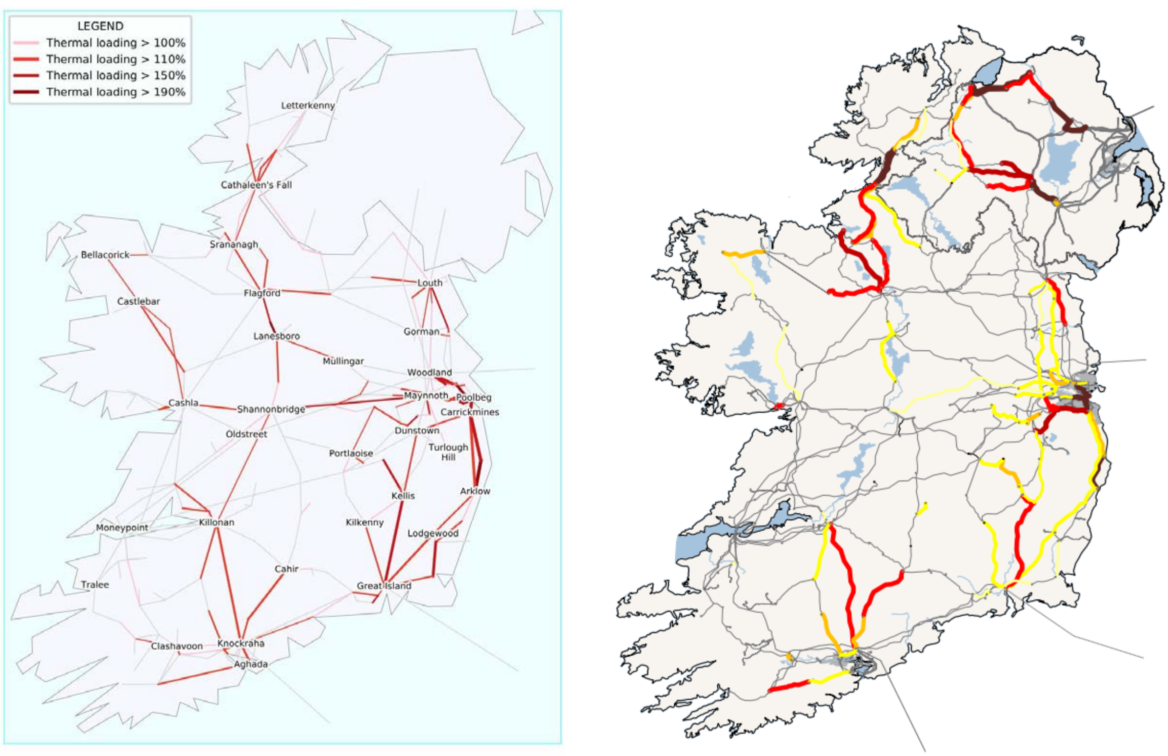
[60] The process of addressing the capacity of underground circuits differs significantly from the overhead line equivalent, e.g., there could be a requirement for a new cable route.

3.2 Network modelling results

3.2.1 Benchmarking with the Shaping Roadmap

Prior to the assessment of the Accelerated Decarbonisation Pathway, a benchmarking network simulation was carried out to ensure the model results can be considered as being on a consistent baseline to the analysis of the *Shaping Roadmap*. The hourly plant position and interconnector dispatch results from the day-ahead schedule of the SOEF Baseline, as presented in Section 2.3 above, was considered in this exercise. These hourly results, in combination with the circuit-level assumptions of the *Ten-Year Transmission Forecast Statement*, were used to model the hourly flows of electricity through each line of the transmission network in Ireland. The resulting thermal overloading is presented in Figure 36 below.

Figure 36: Thermal overloading in 2030 in the SOEF Baseline (left) and the *Shaping Roadmap* (right)



3.2.2 Generation opportunity analysis

In our simulation of the Accelerated Decarbonisation Pathway, where possible, future renewable capacity connections have been assumed clustered at existing and new looped-in transmission substations on the 220 kV and 400 kV transmission network.

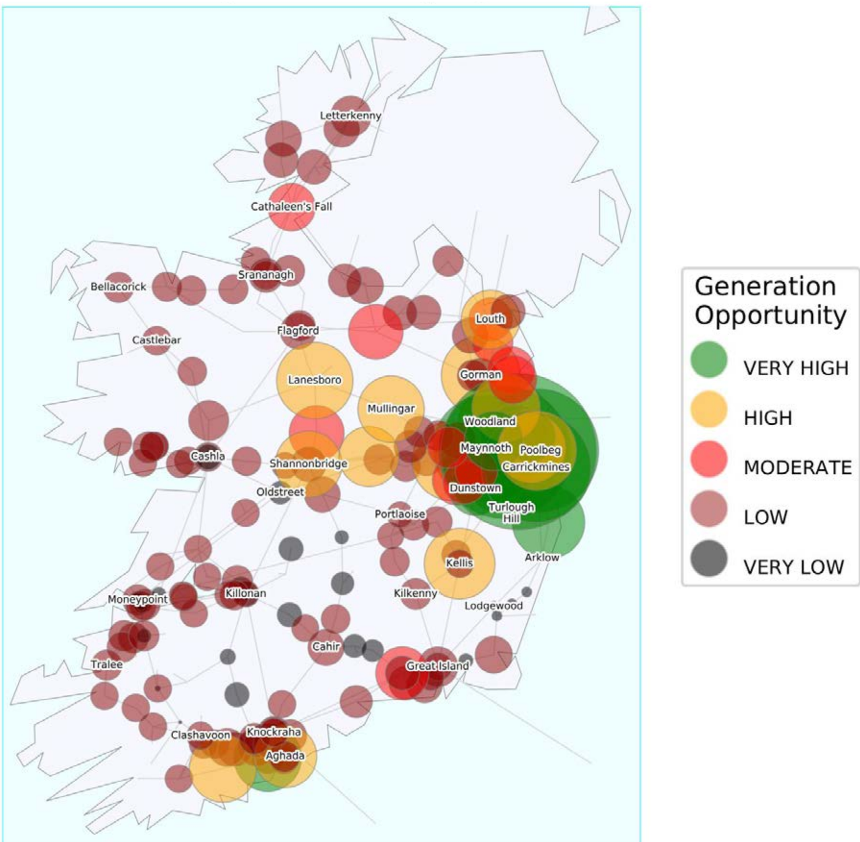
The spatial distribution of this generation capacity has been based on a relative generation opportunity analysis of the 2030 spot year that primarily highlighted 220 kV stations in the Dublin, South, the Midlands, and North-East regions of Ireland as possessing the greatest potential for further connection of generation assets.

The approach, which was agnostic of generation technology, involved an optimisation to identify locations that are most beneficial to the minimisation of network constraint.

Figure 37 below highlights the relative capability of the transmission nodes in Ireland, with those around the Dublin and Midlands regions offering the greatest potential, presented in green and orange respectively. The optimisation included consideration of the build-out of fossil fuel-fired generation capacity, e.g., the assumed new-build capacity at Moneypoint resulted in a lower opportunity for renewable generation capacity than the Dublin region.

This approach aligns with the urgency required to accommodate a large increment of renewable generation in the rapid timeframe assumed in the Pathway.

Figure 37: Relative generation opportunity analysis in 2030 in Accelerated Decarbonisation



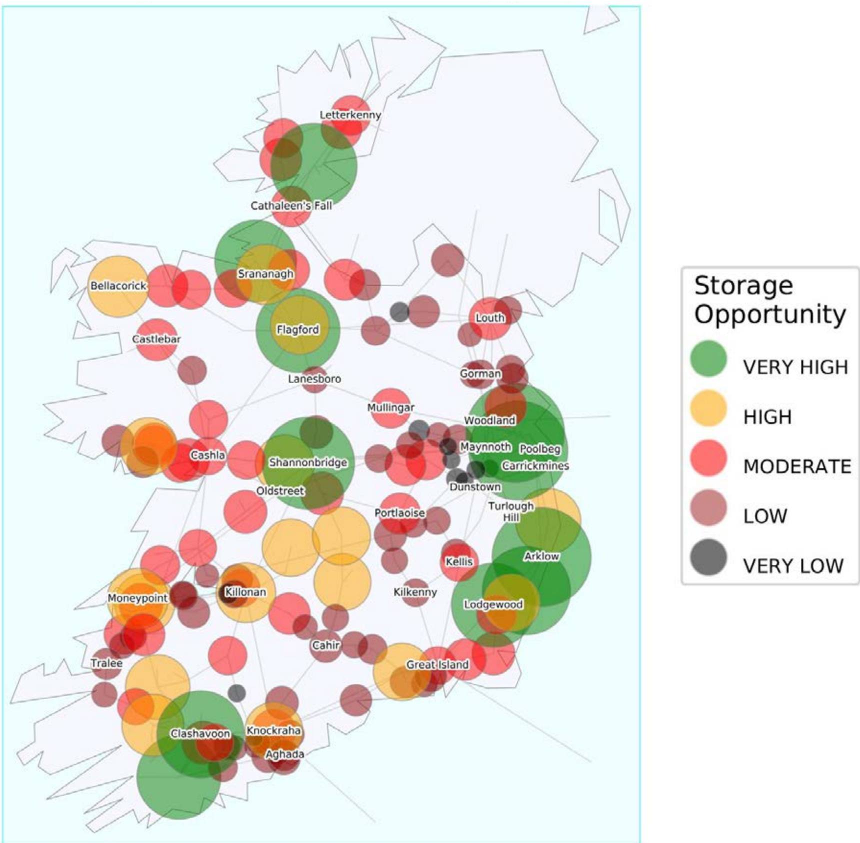
3.2.3 Energy storage technologies opportunity analysis

By 2030, the Accelerated Decarbonisation Pathway includes a portfolio of approximately 1.9 GW of battery storage assets connected throughout the transmission network in Ireland. We have spatially distributed these assets in the network-level model using the distribution of battery storage applicants in *Enduring Connection Policy (ECP) 2.1*[61] and *2.2*[62].

However, existing and planned assets are not always optimally located to manage network constraint. Additional storage technology capacity, dedicated to providing constraint management services, was added to the network-level model for the purpose of determining more optimal candidate locations.

Figure 38 below highlights the relative performance of potential storage assets at candidate locations throughout the Irish transmission network, as determined by an optimisation to minimise renewable constraint. Our analysis highlights that there is high opportunity, presented in green, demonstrated in locations in the North-West, the Midlands, South-East and South-West regions. Moderate opportunity, presented in orange, occurs in several locations throughout the system.

Figure 38: Energy storage technology opportunity analysis in 2030 in Accelerated Decarbonisation



61 ECP-2.1
62 ECP-2.2

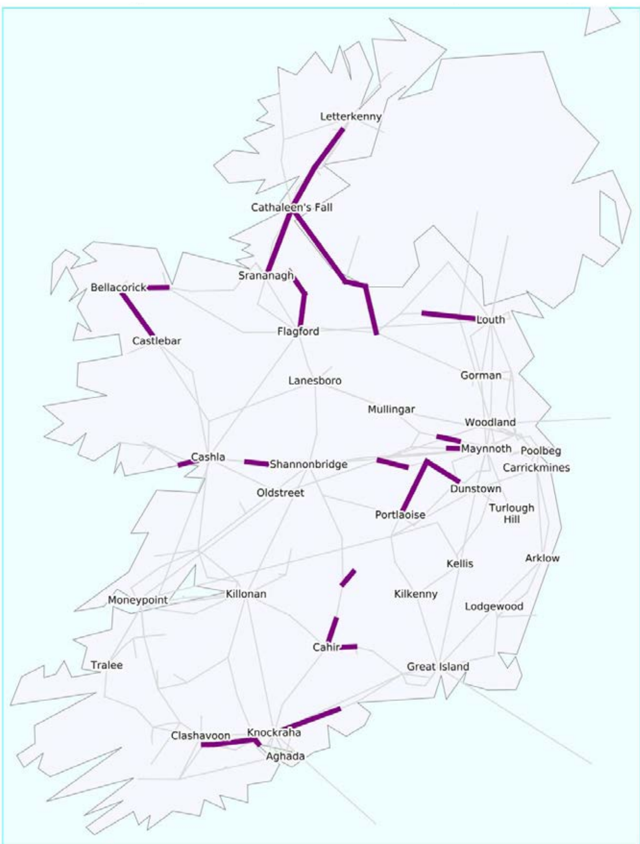
3.2.4 Dynamic line rating

Our assessment of dynamic line rating candidates identified a number of 110 kV circuits throughout the system that could transfer higher levels of power due to local environmental factors, i.e., an increase to the circuit transfer capacity due to local wind speed.

In the absence of detailed overhead line specifications, a conservative approach was used, in which circuits could benefit from an increase in rating of up to 30 MVA, given local wind conditions. This figure was assumed based on the approximate difference between typical summer and winter overhead line ratings. We have therefore assumed that, under the right conditions, summer ratings of lines (typically the binding constraint when demand is low and circuit ratings are lowest) could be increased to the level of their corresponding winter ratings.

Many overhead lines demonstrated some benefit from using DLR, with others demonstrating more pronounced benefits. Figure 39 below indicates, in purple, the locations of the 27 highest performing candidate circuits, based on the analysis of the modelled 2027 spot year of the Accelerated Decarbonisation Pathway. This model year was used to highlight the potential benefit to the system prior to the delivery of the largest projects of the *Shaping Roadmap*. These overhead line candidates were determined based on the afforded reductions to the volume and frequency of overloading. Many of these circuits still reach their full power transfer capability, resulting in the constraint of renewable generation, but the frequency of constraint events is significantly reduced. The majority of these circuits are assumed to be uprated, furthering the benefit of the technology.

Figure 39: Potential dynamic line rating candidate circuits in Accelerated Decarbonisation



3.3 Regional assessment results

3.3.1 Needs assessment summary

This section summarises the findings for each network region across the four modelled spot years of the Accelerated Decarbonisation Pathway, and suggests how enabling technologies can be used to help mitigate transmission system loading and voltage issues. Technology candidates have been evaluated based on their potential to increase the connection of renewable generation assets prior to the arrival of the projects assumed in the *Shaping Roadmap*, i.e., the primary objective being to decarbonise the Irish power system at the greatest rate possible. The figures presented throughout this section use red lines to indicate the circuits in which overloading occurs.

To ensure a robust test of a power system with average renewable penetration exceeding 80% by 2030, market schedules for the unconstrained Accelerated Decarbonisation Pathway were examined for the 2022, 2025, 2027 and 2030 spot years. The use of day-ahead market positions of plant resulted in larger power flows from the South regions towards the Dublin region along the South-East corridor in hours in which the fossil gas-fired units connected to the Irishtown and Huntstown 220 kV stations are offline but fossil gas-fired units in the South regions are more active. This modelling approach represents a deviation from that assumed in the *Shaping Roadmap*, in which two units were considered constrained on in Dublin in all hours during the network-level analysis.

Table 9 below presents a comparison of projects[63], both upgrades to existing circuits[64] and deployment of new-build circuits[65], identified as being required in the *Shaping Roadmap* and in the Accelerated Decarbonisation Pathway.

[63] The Arklow – Ballybeg – Carrickmines corridor may require high temperature, low sag conductor (HTLS) uprating, in addition to upvoltaging.

[64] The 110 kV conductor of Arklow – Ballybeg – Carrickmines is assumed replaced with a 220 kV conductor, using the same tower structures.

[65] The new South Dublin circuit may need to have a higher than standard rating or be built at a higher voltage level to provide greater capacity.

Table 9: Identified projects required in the *Shaping Roadmap* and Accelerated Decarbonisation

Network Development	*Shaping Roadmap*	Accelerated Decarb.
Development Projects		
Inchicore – Poolbeg 220 kV No. 1 uprate	✓ Included	✓ Included
Inchicore – Poolbeg 220 kV No. 2 uprate	✓ Included	✓ Included
Arklow – Ballybeg – Carrickmines 220 kV upvoltage	✓ Included	✓ Included
New South Dublin circuit	✓ Included	✓ Included
New North Dublin 400 kV circuit	✓ Included	✓ Included
North Wall – Poolbeg 220 kV replacement	✓ Included	✓ Included
Finglas – North Wall 220 kV replacement	✓ Included	✓ Included
Arklow 220/110 kV transformer capacity	✖ Not included	✓ Included
Great Island 220/110 kV transformer capacity	✓ Included	✓ Included
Crane – Wexford 110 kV capacity	✓ Included	✓ Included
Great Island – Kellis 220 kV uprate	✓ Included	✓ Included
Arklow – Carrickmines 220 kV uprate	✖ Not included	✓ Included
Lanesboro – Sliabh Bawn 110 kV uprate	✓ Included	✓ Included
Athy – Carlow 110 kV uprate	✓ Included	✓ Included
Maynooth - Shannonbridge 220 kV uprate	✖ Not included	✓ Included
Cahir – Barrymore Tee – Knockraha 110 kV uprate	✓ Included	✓ Included
Knockraha – Killonan 220 kV capacity	✓ Included	✓ Included
Flagford – Sliabh Bawn 110 kV uprate	✓ Included	✓ Included
Flagford – Sligo 110 kV capacity increase	✓ Included	✓ Included
Great Island – Lodgewood 220 kV uprate	✖ Not included	✓ Included
Dunstown – Kellis 220 kV uprate	✖ Not included	✓ Included
Great Island – Kilkenny 110 kV uprate	✓ Included	✓ Included
Arklow – Lodgewood 220 kV uprate	✖ Not included	✓ Included
Drybridge – Louth 110 kV uprate	✓ Included	✓ Included
Arva – Carrick-On-Shannon 110 kV uprate	✓ Included	✓ Included
New circuit capacity for Donegal	✓ Included	✓ Included
Carrickmines – Poolbeg 220 kV uprate	✓ Included	✓ Included
Kiloteran – Waterford 110 kV uprate	✓ Included	✓ Included
Cashla – Salthill 110 kV uprate	✓ Included	✓ Included
Athlone – Lanesboro 110 kV uprate	✓ Included	✓ Included
Kilteel – Maynooth 110 kV uprate	✓ Included	✓ Included
Bandon – Dunmanway 110 kV uprate	✓ Included	✓ Included
Baroda – Monread 110 kV	✓ Included	✓ Included
Maynooth – Rinawade 110 kV uprate	✓ Included	✓ Included
Rinawade – Dunfirth Tee 110 kV uprate	✓ Included	✓ Included
Bandon – Raffeen 110 kV uprate	✓ Included	✓ Included
Galway – Salthill 110 kV uprate	✓ Included	✓ Included
Louth – Oriel 220 kV uprate	✓ Included	✓ Included
Oriel – Woodland 220 kV uprate	✓ Included	✓ Included

3.3.2 North-West

The transmission network in the North-West region primarily consists of 110 kV transmission lines, much of which is overloaded throughout the 2022 spot year. The 220 kV network in the region, although limited, strengthens the local network and provides security of supply. The region is characterised by relatively low demand and high output of onshore wind, which is typically exported from the region towards larger demand centres elsewhere in Ireland. Figure 40 below illustrates how thermal loading increases from 2022 to 2025.

In 2027, loading to the west of the region is reduced by the delivery of the North Connacht project. A significant portion of the *Shaping Roadmap* transmission project portfolio is located in this region, a combination of uprates, upvoltaging, and new-build projects. When delivered, these projects address most of the renewable network constraint in the region, but do not provide significant additional strategic capacity. Figure 41 below illustrates the improvement in thermal loading in 2027 and 2030.

Network-level solution options in the North-West region

The North-West region benefits from the following approaches:

- **Network development**: Additional circuit development solutions were not considered beyond those of the *Shaping Roadmap* portfolio.
- **Cluster stations**: The ability to create worthwhile cluster stations in this region relies on the network development projects of the *Shaping Roadmap* being implemented, and so we have not explored their benefits in the North-West.
- **Dynamic line rating**: DLR would offer increased transmission capacity during hours of constraint, and enable local storage assets to operate more effectively. In many examples, DLR was found able to reduce the duration of constraint events in the region by over 50%.
- **Energy storage**: Strategically located storage assets offer immediate benefit by reducing the level of renewable export from the region, and storing the energy for use at times of lower renewable generation. Due to the constrained nature of the region, long-duration storage technologies would provide the greatest benefit. Short-duration storage technologies may experience limited operating capability due to the significant constraint in the surrounding regions of the network. Our analysis highlighted that the Clogher 110 kV station offered the most opportunity for this technology, with Flagford, Srananagh, and Bellacorick offering comparable benefit.
- **Reactive/synchronous power compensation**: These technologies are required immediately, for both low and high voltage reasons. Local wind assets could potentially contribute towards these requirements, but static synchronous compensator (STATCOM) or synchronous condenser technologies offer the greatest value in the North-West, particularly towards the north of the region. Local voltage support may also be required to manage the risk of larger-than-usual voltage phase angles that can arise due to higher line loadings caused by widespread use of dynamic line rating.
- **Power flow control technology**: These technologies could be used in this region to balance local power flows. However, the benefit is small compared to the other available options, as the technology requires parallel redundant network infrastructure, which is limited. Additional capacity is required to fully realise this technology in this region, either via new circuit development, uprating, upvoltaging or dynamic line rating.

Figure 40: Transmission network needs assessment of the North-West, 2022 (left) and 2025 (right)

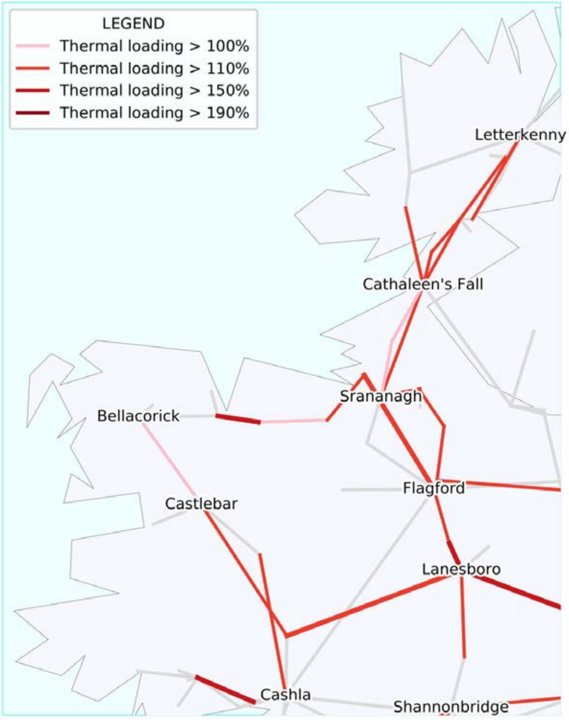
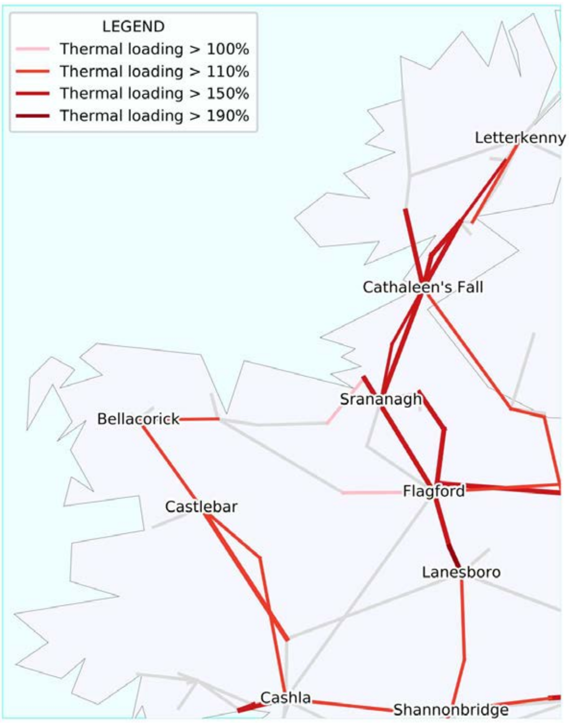


Figure 41: Transmission network needs assessment of the North-West, 2027 (left) and 2030 (right)



3.3.3 South-East

The transmission network in the South-East region consists of both 110 kV and 220 kV infrastructure. The region is characterised as a key transmission corridor between the Cork and Dublin regions, both home to relatively high demand and fossil gas-fired generation. In future, both regions are expected to be hubs for large-scale offshore wind generation capacity. Figure 42 below illustrates how thermal loading increases from 2022 to 2025.

Due to the unconstrained nature of the market schedule modelled, the South-East region experiences higher power flows from the South-West towards the Dublin region. Loading is driven by a combination of onshore wind generation in the South of Ireland and the local fossil gas-fired plant located near the Aghada and Great Island 220 kV stations. The arrival of the Greenlink interconnector at the Great Island 220 kV station from 2025 often exacerbates the loading in this region.

In 2027 the average loading in this region increases significantly. Generation of local onshore wind and solar PV assets increases, and new network projects are yet to be delivered in the region. A small transmission network project portfolio assumed in the *Shaping Roadmap* is located in this region, a mixture of uprating and upvoltaging projects. When completed, these projects will not remove all the constraint in the region, and will therefore not provide significant additional strategic capacity as the system moves towards 80% renewable electricity. Figure 43 below illustrates how thermal loading improves in 2027 and 2030.

Network-level solution options in the South-East region

The South-East region benefits from the following approaches:

- **Network development**: Further 220 kV uprating is required in this area, particularly in the case of the Great Island – Lodgewood 220 kV overhead line. Additional capacity may also be required between the Dunstown – Kellis, Arklow – Lodgewood and Arklow – Carrickmines 220 kV circuits, driven by the deployment of onshore wind generation connections throughout the Midlands, which utilise the 220 kV and 400 kV network.
- **Cluster stations**: If the 220 kV network in this region is uprated, cluster stations can be used to reduce the loading on the local 110 kV network, and as connector points for new-build renewable generation projects.
- **Dynamic line rating**: In comparison to other regions, our analysis did not identify many strong candidates for dynamic line rating in the South-East region, as the loading in the region is not typically induced by local renewable generation.
- **Energy storage**: Storage assets provide some benefit in this region in reducing the volume of power that needs to flow through the region, particularly on the 110 kV network.
- **Power flow control**: This has been modelled on the 220 kV circuits, taking advantage of the parallel paths (one of which will be uprated as part of the *Shaping Roadmap* portfolio) to utilise redundant capacity to better manage the interaction of local interconnection, fossil gas-fired plant and renewable assets. To fully realise this technology, more of the 220 kV network in this region will need to be uprated.
- **Reactive/synchronous power compensation**: This is not expected to be required in the region. Even when considered without the Great Island fossil gas-fired plant and the Greenlink interconnector, the voltage in the region remains within acceptable standards.

Figure 42: Transmission network needs assessment of the South-East, 2022 (left) and 2025 (right)

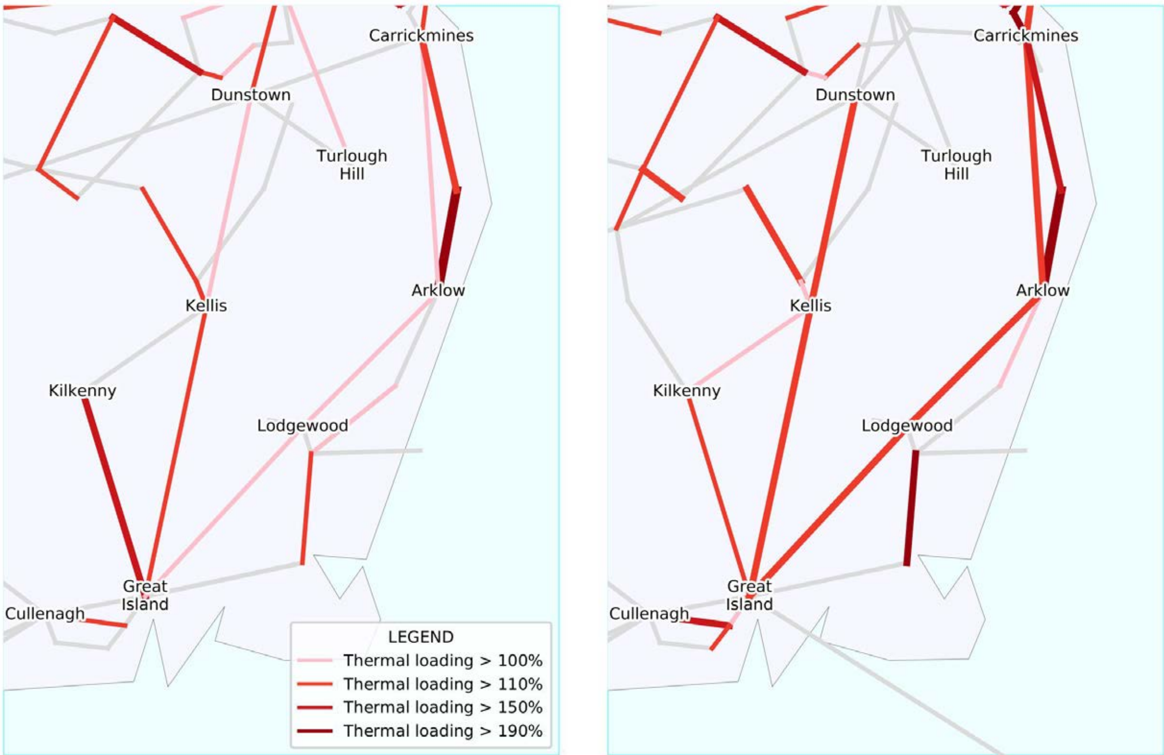
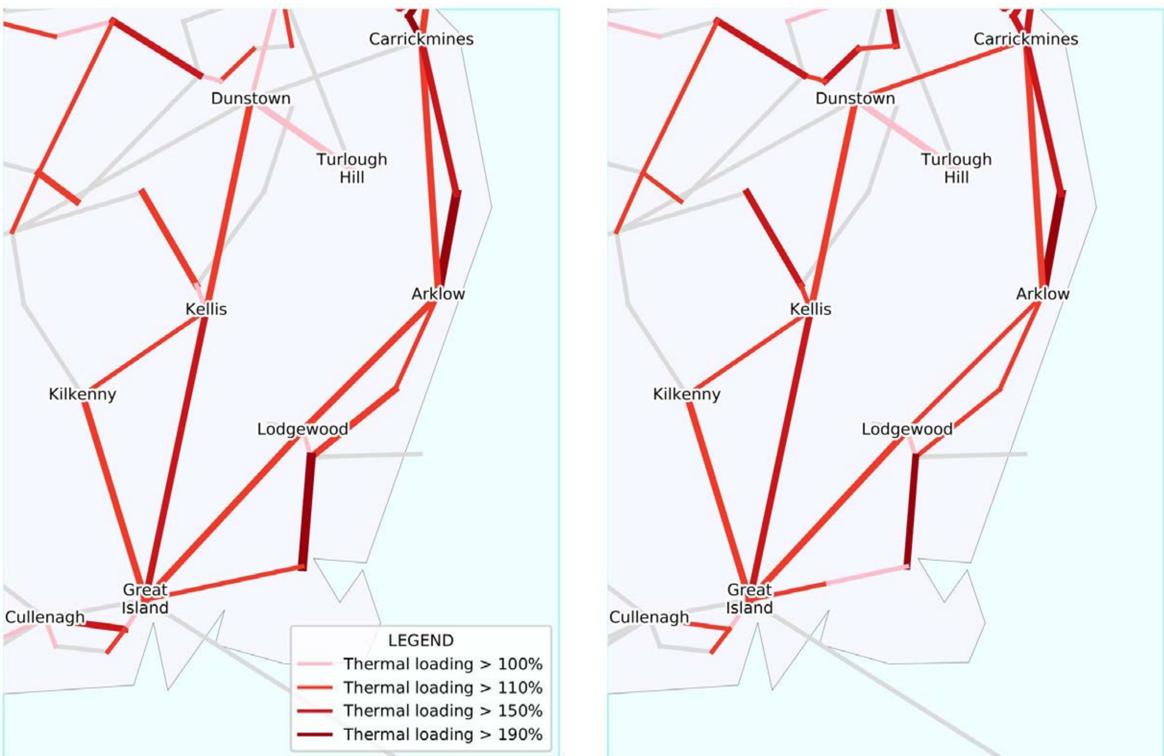


Figure 43: Transmission network needs assessment of the South-East, 2027 (left) and 2030 (right)



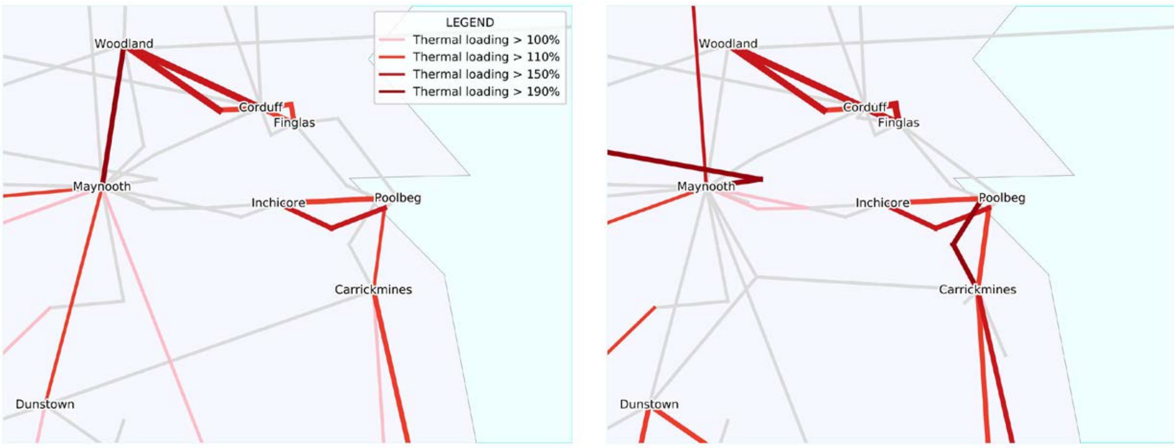
3.3.4 Dublin

The network in the Dublin region consists of primarily 220 kV circuits, both overhead lines and underground cables. The 400 kV network in the north (Woodland) and south (Dunstown) of the region plays an important transmission system role, by creating a high-capacity corridor to the west coast of Ireland, and accommodating the EWIC interconnector between Ireland and Great Britain.

At present, the region is characterised by high levels of local fossil gas-fired generation, and a relative prominence of large energy user connections. In future, large-scale offshore wind generation capacity is expected to be connected along the east of the region, into nodes such as the Belcamp, Poolbeg, and Carrickmines 220 kV stations. This is expected to be facilitated by a number of 220 kV underground cable replacements, and a new 400 kV circuit connecting the Dunstown, Woodland, and Belcamp transmission stations. As is presented in Figure 44 below, the Dublin region experiences two main thermal overloading issues in 2022 and 2025:

- Transferring power beyond the Woodland 220/400 kV station, and towards the Maynooth and Finglas 220 kV load centres; and
- Transferring power into the south of Dublin via the Carrickmines 220 kV station, and towards the Inchicore and Castlebagot 220 kV load centres.

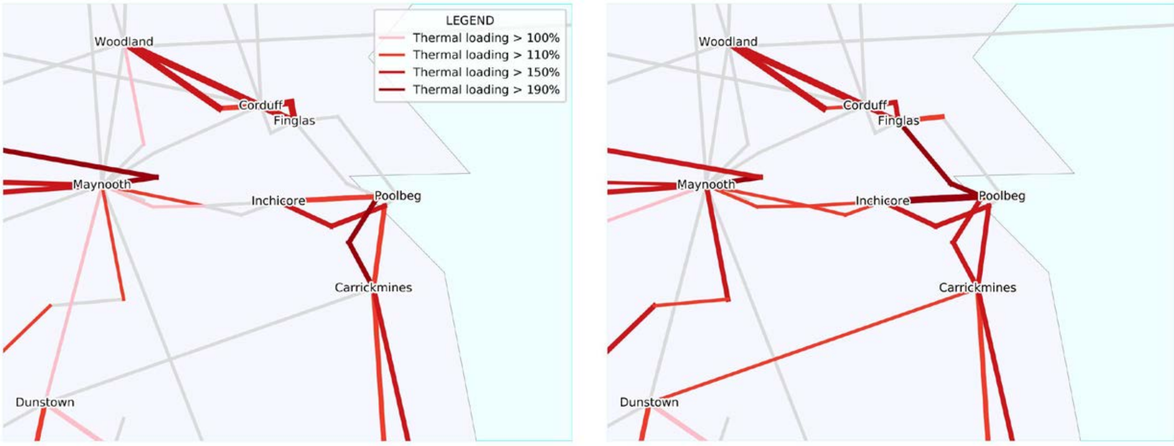
Figure 44: Transmission network needs assessment of Dublin region, 2022 (left) and 2025 (right)



As presented in Figure 45 below, these network issues remain roughly constant until offshore wind generation capacity connects prior to the 2030 spot year. Once this capacity is connected, the overloading increases in magnitude and spreads to affect the majority of the transmission circuits in the region.

The *Shaping Roadmap* projects in this region largely succeed in dealing with local volumes of renewable constraint. The 400 kV projects provide strategic capacity, and the 220 kV underground cable solutions help to meet the requirements of a power system capable of maintaining greater than 80% renewable penetration, when complimented by the solutions listed below.

Figure 45: Transmission network needs assessment of Dublin region, 2027 (left) and 2030 (right)



Network-level solution options in the Dublin region

This Dublin region benefits from the following approaches:

- **Network solutions:** The *Shaping Roadmap* identified several network development projects appropriate for increasing the transmission capacity throughout the region, and they perform well in our optimisation in terms of reducing future network constraint; our analysis therefore identified no need for further new-build circuits. However, it was observed that further strategic transmission capacity is likely to be required between the Inchicore and Carrickmines 220 kV stations. This could be achieved by utilising higher capacity 220 kV underground cables.
- **Cluster stations:** There is no clear need for this approach in the region. Numerous 220 kV stations are in place that can facilitate the expected arrival of large-scale offshore generation development.
- **Dynamic line rating:** Due to the transmission network consisting of mostly underground cables in the Dublin region, there is no clear requirement for this technology.
- **Energy storage**: Storage technologies offer worthwhile benefit in this region, by reducing the level of power that needs to flow through it. This benefit is greatest in locations close to the coast that facilitate the connection of offshore wind generation, including the Poolbeg/Shellybanks, Huntstown, Carrickmines and Belcamp 220 kV stations.
- **Power flow control**: The Carrickmines 220 kV phase-shift transformer is an important operational tool for the region. With a more dynamic power system, particularly due to the local offshore wind generation, and a more extensive underground cable network, further power flow control options are required to manage the challenging power flows in a low impedance network.
- **Reactive/synchronous power compensation**: The largest challenge for the Dublin region will be the displacement of the Min Gen DS3 limits, while maintaining voltage support, synchronous compensation, and a source of local active power generation. A mixture of STATCOMs and synchronous condensers are required throughout the region, ideally located close to the major demand centres, for example, close to the central transmission corridor, near the Inchicore and Castlebagot 220 kV stations.

3.3.5 South-West

The network in the South-West region consists of primarily 110 kV and 220 kV overhead line infrastructure. The 220 kV network in the west of the region collects onshore wind generation, and transfers it towards the 400 kV network at Moneypoint and the Knockraha 220 kV station in Cork.

The region is characterised by significant onshore wind capacity that has connected steadily throughout the last two decades, and recent new-build fossil gas-fired units located close to the Aghada 220 kV station in Cork. The local network has been significantly reinforced to cater for this generation mix, by the building of collector stations, and use of high temperature, low sag conductor (HTLS) technology to maximise the capability of the 220 kV overhead lines.

In the years 2022 to 2025, the South-West region does not experience any significant thermal loading issues, as presented in Figure 46 below. By 2025, STATCOMs are in assumed place to manage voltage support, and new capacity between the Clashavoon and Moneypoint stations has been completed.

Figure 46: Transmission network needs assessment of the South-West, 2022 (left) and 2025 (right)

Figure 47: Transmission network needs assessment of the South-West, 2027 (left) and 2030 (right)

The Celtic interconnector is assumed to connect prior to 2027 and induces overloading on a number of circuits, as presented in Figure 47 above. This effect occurs in hours of both low and high renewable operating conditions:

- During periods of high renewable generation, renewable electricity generated in the west of the region is transferred and exported to France through the Celtic interconnector. This can cause overloads on the 110 kV network; and
- When Celtic imports, with local fossil gas-fired plant dispatched on and at times of relatively low local demand, circuits such as the Killonan – Knockraha 220 kV line can experience network constraint. This situation has the potential to limit security of supply in times of low generation adequacy levels.

Network-level solution options in the South-West region

The South-West region benefits from the following approaches:

- **Network development**: Our analysis highlighted that there is no clear requirement for significant network development in this region. Many of the key circuits have already been uprated throughout the past decade.
- **Cluster stations**: This strategy has already been deployed successfully in this area and there is minimal scope for further applications.
- **Dynamic line rating**: Some circuits in the region, such as the Killonan – Knockraha 220 kV line would benefit from additional capacity.
- **Energy storage**: These assets provide some benefit in this region by reducing the level of power that needs to flow to and from the Celtic interconnector. Local energy storage assets could also help with the reserve requirements of the Celtic interconnector.
- **Power flow control**: The network connecting to the Knockraha station needs more enhanced power flow control. Many of the circuits are already uprated and would benefit from more optimal operation.
- **Reactive/synchronous power compensation**: New STATCOMs, the synchronous compensation project at Moneypoint, and the Celtic interconnector, will provide a platform for robust voltage management in the region.

3.3.6 The Midlands

The network in the Midlands region consists of 110 kV, 220 kV, and 400 kV transmission infrastructure. The region is characterised as being a key transmission corridor between the west and east of the transmission system.

Figure 48 below illustrates how thermal loading evolves in the region from 2022 to 2025. Many circuits experience some level of thermal overloading, but, in aggregate, the loading remains similar and does not reach the overloading levels observed in the other regions.

Key overloaded circuits in the region include the long stretch of 220 kV overhead line that links the Killonan, Shannonbridge, and Maynooth 220 kV stations. These circuits are old by transmission system standards and are likely to be in need of replacement in the coming years due to deterioration of asset health.

Figure 48: Transmission network needs assessment of the Midlands, 2022 (left) and 2025 (right)

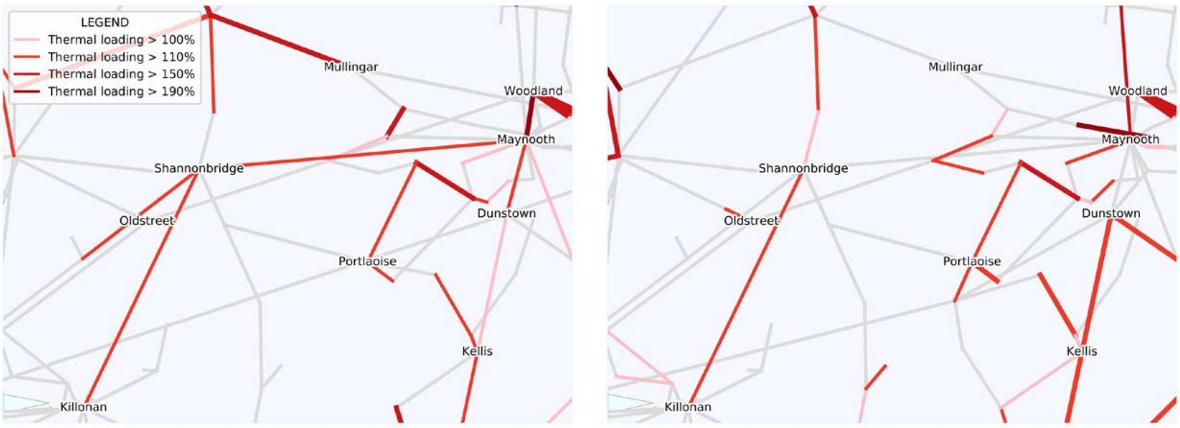
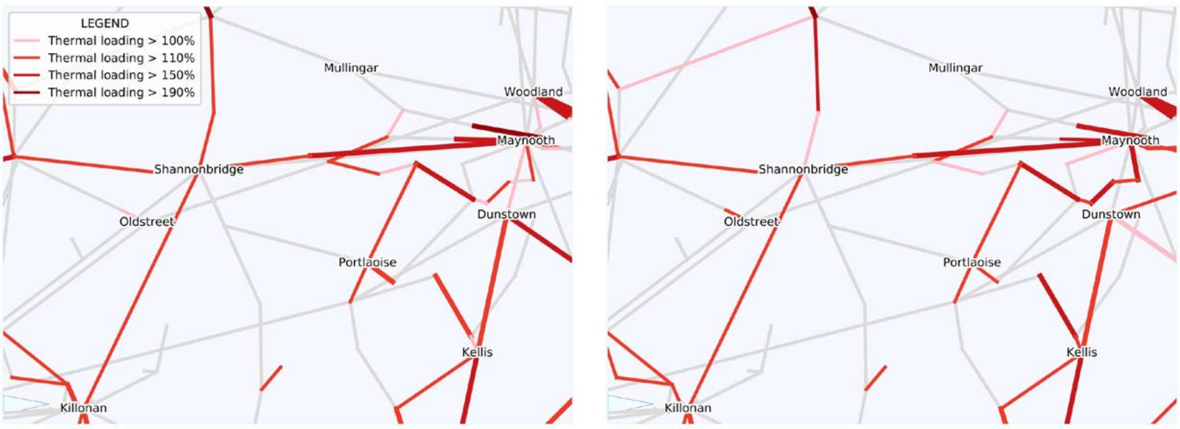


Figure 49: Transmission network needs assessment of the Midlands, 2027 (left) and 2030 (right)



In 2027 the loading in this region increases significantly. Onshore wind and solar PV generation on the system increases, and new network projects have yet to be delivered in the region. A small *Shaping Roadmap* transmission network project portfolio is located in this region, mainly 110 kV uprates. When completed, these projects will not remove all local constraint, and will therefore not provide significant additional strategic capacity for the region. Figure 49 above illustrates how thermal loading evolves in 2027 and 2030.

Network-level solution options in the South-West region

The Midlands region benefits from the following approaches:

- **Network solutions**: The *Shaping Roadmap* transmission network projects focussed on the 110 kV network in this region. However the region has plentiful 220 kV and 400 kV infrastructure; overhead lines such as the Maynooth – Shannonbridge 220 kV could be uprated to accommodate large renewable project connections.
- **Cluster stations**: Due to the relatively low capacity 110 kV network infrastructure in this region, and the significant renewable resource, the region benefits from connecting a portion of the local wind and solar capacity to the 220 kV and 400 kV substations, and removing connectivity to the local 110 kV network.
- **Dynamic line rating**: DLR offers potential benefit in this region, but many 110 kV circuits are first in need of uprating due to the low rating brought by their vintage.
- **Energy storage**: Storage assets can provide some benefit in this region, minimising the level of power that needs to flow through the region, particularly on the 220 kV network, which needs to be upgraded.
- **Power flow control**: Such technology could be used here to significant effect. There are 220 kV parallel paths, some of which will be uprated under the assumptions of the *Shaping Roadmap*, and power flows could more effectively balanced, and utilise any redundant capacity on the 220 kV circuits.
- **Reactive/synchronous power compensation**: Reactive power is needed in the region. Locating such technology in the Midlands helps to better connect the less reinforced network in the North-West region to that in the south of Ireland.

3.4 Conclusions of the network analysis

The following list summarises the key findings of the technology opportunity analysis, and transmission system needs assessment performed as part of this study:

- To facilitate a power system capable of accommodating greater than 80% renewable electricity by 2030, and achieving the power sector ambitions of the *Climate Action Plan 2021*, a Pathway to a Net Zero power system needs to be considered now. Renewable capacity needs to urgently connect to the transmission system. To enable this, zero-carbon solutions to DS3 limits, and the connection of STATCOMs and synchronous compensation technologies throughout the system is vital.
- **All *Shaping Roadmap* transmission network projects are required**, and there is a clear need to increase the project portfolio to minimise constraint and enable greater than 80% renewable electricity in Ireland. In particular, the system would benefit from the following considerations:
  - Uprating more of the 220 kV network, using high temperature, low sag conductors;
  - Building more 220 kV cluster stations in optimal locations in the Midlands and South-East regions to maximise the potential for renewable capacity connections;
  - Using dynamic line rating in the congested 110 kV network. This is a mature technology that has been demonstrated and is trusted world-wide; and
  - Increased deployment of power flow control devices for the 220 kV network, particularly in the regions with 220 kV redundancy such as in the vicinity of the Great Island and Knockraha 220 kV stations, where at least two 220 kV circuits can be available with spare capacity following a contingency. The underground cable network in south Dublin will also benefit from further power flow control.
- If renewable capacity connections can be accelerated in-line with the assumptions detailed in Section 2.1.6 above to enable the lowest volume of cumulative CO_2 emissions from the power sector, it is likely that new network capacity will not be in place on time, and constraint volumes will increase. Technologies new to the Irish network are required to mitigate this impact, in particular the strategic deployment of long-duration energy storage technologies.
- It is evident that the *Shaping Roadmap* will not deliver significant strategic capacity or headroom beyond the 70% renewable electricity targeted. New technologies can enable the *Shaping Roadmap* development project portfolio to provide a strategic platform for further renewable capacity to go beyond this now superseded target.
- In an ‘unconstrained’ power system, without consideration of DS3 limits, there is increased loading on the network feeding the Dublin region. It is critical for more active power sources in Dublin region to be delivered to ensure security of supply.
- Locational signals for new technologies such as synchronous condensers and energy storage technologies would be beneficial, to maximise the benefits they offer to the power system in Ireland.

4 Key findings of the study

In this study we have set out to explore a series of Pathways out to 2030 for the Irish power sector, to quantify the cumulative carbon budget unlocked by going beyond EirGrid's *Shaping our Electricity Future Roadmap* and achieving the 2030 targets of the *Climate Action Plan 2021*.

In our modelling of the Irish power sector throughout this study we have built upon our framework used in previous studies, to not only simulate the market at the system level, but also at the network level with explicit consideration of hourly power flows through each transmission line in Ireland. This circuit-level analysis, enabled by the collaboration of Baringa and TNEI, has allowed us to consider options for the spatial deployment of generation assets, and evaluate the hourly constraint of renewables, providing a holistic view of our Pathways.

Previous studies into decarbonisation of the Irish power sector have typically focussed on the year 2030 as an isolated point in time, exploring the sector in an 'end state', as has the ambition of the Irish Government. This approach does not consider the cumulative emissions of CO_2 out to a decarbonised 2030 power sector, which is dependent on the Pathway taken to achieve it.

In this study we set out to first model two Pathways to Ireland's 2030 power sector targets, of 80% renewable electricity and 2 million tonnes of CO_2, with different deployment rates of wind and solar capacity procured via RESS auctions, to determine the impact on cumulative emissions. We found that a total of 4 million tonnes of CO_2, twice the power sector emissions in 2030, could be saved by the rapid delivery of renewable capacity following each auction.

We then modelled a third Pathway, Accelerated Decarbonisation, in which Ireland achieves, or exceeds, all of the power sector targets for 2030 stated in the *Climate Action Plan 2021*, including delivery of 8.2 GW of onshore wind, 5 GW of offshore wind, and 3 GW of solar PV capacity. The deployment of this capacity was assumed to proceed at the fastest rate achievable under the current RESS auction schedule, and be enabled by the adoption of a comprehensive suite of zero-carbon system services provided by synchronous condensers and dedicated battery storage assets.

Achieving the rapid rate of renewable capacity deployment assumed in this final Pathway requires the build-out of all network development projects assumed in the *Shaping Roadmap*, as well as incremental circuit upgrades beyond this. Where long lead times apply to network upgrades, and prevent their timely delivery in-line with the deployment of renewable capacity, strategic spatial deployment of enabling technologies can act to manage constraint across the Irish network; such as STATCOMs in Greater Dublin, power flow control in the South-East and South-West, and dedicated energy storage capacity in the North-West.

The total carbon emissions produced by the Irish power sector between 2021 and 2030 in this most ambitious Pathway, which represents the limit of ambition towards decarbonisation in Ireland under current policies, total 66 million tonnes of CO_2. If cumulative CO_2 emissions are to be reduced below this figure, and be brought closer to the indicative 55 million tonnes suggested for the sector, major interventions beyond current policy will be required.

Around 45 million tonnes of CO_2 are emitted from the Irish power sector between 2021 and 2025 in this Pathway, with carbon intensive fossil fuels including coal, distillate oil, and peat providing disproportionate contributions; coal-fired generation alone contributes 10 million tonnes of CO_2 towards a prospective sectoral carbon budget.

To further reduce emissions on Ireland's Pathway to a decarbonised 2030 power sector, solutions must be implemented to rapidly phase out these carbon intensive fossil fuels in the first half of this unfolding decade.

Deployment of technologies able to provide zero-carbon system-services, development of the transmission network, and the delivery of constraint management solutions must keep pace with renewables. **A total of 15 million tonnes of CO_2 results from the re-dispatch of plant in Ireland to maintain DS3 limits and transmission constraints in the Accelerated Decarbonisation Pathway.**

A faster deployment of enabling solutions than modelled in our Pathway offers further opportunity to reduce the CO_2 emitted from the Irish power sector.

The results of this study indicate a series of key findings regarding the future of the Irish power sector over the decade ahead:

- The total **cumulative CO_2 emissions** from the Irish power sector out to 2030 are **sensitive to the Pathway taken to get there**.
- In Pathways that meet Ireland's 2030 targets, our analysis shows that **cumulative power sector emissions can be reduced by 4 million tonnes of CO_2** by the **rapid delivery of renewables** following RESS auctions compared to a delayed delivery of the same capacity.
- In an ambitious Pathway that **exceeds many of Ireland's 2030 targets**, with rapid delivery of renewable capacity and investment in enabling technologies, our analysis shows that **66 million tonnes of CO_2** are emitted from the power sector in the decade **between 2021 and 2030,** including **6 million tonnes resulting from transmission constraints**.
- This Pathway represents a **saving of at least 6 million tonnes of CO_2** compared to a Baseline of EirGrid's ***Shaping our Electricity Future Roadmap***. However, it still substantially exceeds an **indicative sectoral carbon budget of 55 million tonnes of CO_2**.
- Achieving a carbon budget of 66 million tonnes of CO_2 in the power sector requires the build of **onshore wind and solar PV** capacity as **early in the decade as possible** and **proactive investment in enabling technologies**, including:
  - Sources of **system flexibility** to manage **renewable oversupply**, such as interconnection, demand-side response, and energy storage technologies;
  - Provision of **zero-carbon system services** from battery assets and synchronous condensers, to **unwind DS3 limits** and moderate **renewable curtailment**; and
  - The continued **development of the transmission network** including all projects identified in the *Shaping Roadmap*, and further upgrades to circuits throughout Ireland. The rapid deployment of renewables also requires the **strategic deployment of constraint management solutions**, such as dynamic line rating, power flow control, and dedicated energy storage assets, to address **renewable constraint** due to transmission limits.
- Use of **carbon intensive fossil fuels including coal and peat in the first half of the decade** 'locks in' substantial emissions, and puts pressure on carbon budgets. Our analysis suggests that **66 million tonnes of CO_2** between 2021 and 2030 represents the **minimum achievable for the Irish power sector under current policies; major and fast interventions** are required to move the dial past this figure, including solutions to **phase out the usage of these carbon intensive fuels**, and an acceleration of renewables and enabling technologies **above and beyond existing policy**.

Appendix A Dispatch-down in Ireland

A.1 Definitions of dispatch-down actions

In the *Shaping our Electricity Future Technical Report*[66], EirGrid and SONI defined three distinct forms of dispatch-down actions in Ireland and Northern Ireland that reduce the output of renewable generators below their theoretical maximum. Table 10 below presents a summary of the three types of actions.

To be 'turned down' a renewable generator must be 'controllable', i.e., it must be possible to remotely disconnect the generator from the network.

Table 10: Dispatch-down actions in Ireland

Dispatch-Down	Oversupply	Curtailment	Constraint
Definition	Oversupply actions occur for two reasons: 1. Volumes in the day-ahead market at or below the cleared price exceed the total market and/or physical demand; 2. If large volumes of renewable outturn are expected, plant can be incentivised to 'self-curtail' to not be exposed to negative day-ahead prices.	Curtailment actions result from the need for maintain system-wide DS3 limits (operational constraints) including: 1. SNSP limit; 2. RoCoF limit; 3. Minimum inertia; 4. Minimum units for system stability limits.	Constraint actions occur after the day-ahead schedule, to account for local limits in the capacity of the network, often termed 'grid boundaries'. If these limits are due to be exceeded in the day-ahead schedule, plant 'behind' these limits will be turned-down.
Which plant?	Any plant on the network.	Any plant on the network.	Plant in the region where the constraint occurs.
When?	In the day-ahead schedule.	In the balancing market.	In the balancing market.
2021 outturn[67]	0.5%	3.0%	4.4%

[66] Shaping our Electricity Future Technical Report
[67] Historical Monthly & Quarterly Dispatch-Down Summary Report (Spreadsheet)

A.2 Potential mitigating measures

As the penetration of intermittent renewables in an electrical system increases, dispatch-down actions become a fundamental blocker to the potential zero-carbon electricity. A series of technical and operational solutions to mitigate these actions are being explored in markets across Europe, to ensure the enablement of renewable ambitions.

Below is a brief, high-level overview of some of these potential measures, which have shown potential in our analysis of the Irish system:

- **Oversupply**: At the day-ahead stage, **system flexibility** offers the key to fully utilising renewable generation in its hours of abundance. Demand-side flexibility, being able to shift load towards hours of high wind and solar availability, and away from hours of carbon intensive generation, acts to reduce both oversupply and CO_2 emissions. Similarly, energy storage in all forms is able to take in renewable power that would otherwise be turned down as oversupply, and release it in other hours, where it is most needed. These storage solutions include both those considered as conventional storage assets such as battery energy storage systems (BESS), pumped hydro energy storage (PHES), and other emerging long-duration technologies, including compressed air (CAES) and liquid air energy storage (LAES), and a suite of thermal storage solutions. Power-to-X technologies, such as electrolysis of green hydrogen, present additional opportunities to make use of excess zero-carbon energy to decarbonise the power sector, acting as a form of long-duration storage, or to decarbonise other sectors. Interconnectors allow arbitrage of volatility in weather patterns across markets, by exchanging excess renewable power during hours of oversupply between markets.
- **Curtailment**: System-wide operational constraints, such as the DS3 limits in I-SEM, result in the dispatch-down of renewable generation to allow room on the system for fossil fuel-fired generation, as these plant are the conventional sources of system services such as inertia and reserve, but must typically be generating power in order to provide them. Alternative providers such as synchronous condensers, battery energy storage, and demand-side response, can contribute to system service requirements without displacing renewable generation. Provision of these **zero-carbon system services** is therefore vital to reducing the curtailment of renewables.
- **Constraint**: Unlike oversupply and curtailment, which can be addressed with inherently system-level solutions, constraint actions require investment in measures in the affected regions of the network. Reinforcement of the network itself offers a solution, enabling a greater volume of power to flow out of constrained regions during periods of high renewable output. **Strategic deployment of flexible assets**, such as energy storage, behind network constraints can act to reduce renewable constraint. The value provided by energy storage technologies in reduction of constraint increases exponentially with the storage duration of the assets. Smart network solutions, such as dynamic line rating, and power flow controllers, offer further opportunity to manage renewable constraint.

We have included a number of these mitigating solutions in our modelling of the I-SEM system throughout this study, to enable the integration of the renewables assumed in the Baseline and Pathways. Our modelling framework considers these solutions at all stages, such as an hourly optimisation of interconnector flows between markets, helping to unwind some of the dispatch-down burden imposed on Irish renewable assets by their ambitious adoption.

Appendix B Input assumptions

B.1 System-level modelling assumptions

In this Appendix we present the modelling assumptions that underpin the system-level modelling used in this study. The data is presented as follows:

- Table 11 and Table 12 present our all-island assumptions, including DS3 limits;
- Table 13 and Table 14 detail our wind and solar capacity assumptions for Ireland and Northern Ireland respectively; and
- Table 15 and Table 16 provide detail on further assumptions used in the modelling of Ireland and Northern Ireland respectively.

Table 11: All-island modelling assumptions aligned across our Baseline and Pathways

I-SEM Assumptions	Units	2022	2023	2024	2025	2026	2027	2028	2029	2030
Commodity & Carbon Prices										
Coal CIF ARA	*$/tonne*	117	98	87	81	79	77	76	74	73
Gas NBP	*€/MWh*	84	49	29	29	28	27	26	25	25
Oil Brent	*$/bbl*	82	74	69	70	73	76	79	82	84
Carbon EUA	*€/tonne*	88	87	86	89	93	96	100	103	105
Carbon UKA	*£/tonne*	79	74	74	76	80	83	87	91	93
Interconnector Capacity										
Import from GB	*MW*	950	950	950	1,450	1,450	1,450	1,450	1,450	1,450
Export to GB	*MW*	1,000	1,000	1,000	1,500	1,500	1,500	1,500	1,500	1,500
Import from France	*MW*	0	0	0	0	700	700	700	700	700
Export to France	*MW*	0	0	0	0	700	700	700	700	700
Reserve Requirements										
POR	*MW*	325	325	325	500	700	700	700	700	700
SOR	*MW*	325	325	325	500	700	700	700	700	700
TOR1	*MW*	500	500	500	500	700	700	700	700	700
TOR2	*MW*	500	500	500	500	700	700	700	700	700

Table 12: DS3 limit assumptions in our Baseline and Pathways

I-SEM Assumptions	Units	2022	2023	2024	2025	2026	2027	2028	2029	2030
DS3 Limits (Baseline)										
SNSP limit	*%*	75%	75%	75%	85%	85%	85%	85%	85%	95%
RoCoF limit	*Hz/s*	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Minimum inertia	*GWs*	20	20	20	15	15	15	15	15	15
Minimum units - ROI	*#*	4	4	4	4	4	3	3	3	2
Minimum units - NI	*#*	3	3	3	2	2	2	2	2	2
Dublin - 1	*#*	1	1	1	1	1	1	1	1	1
Dublin - 2	*#*	2	2	2	2	2	2	2	2	2
Dublin - 3	*#*	2	2	2	2	2	2	2	2	1
Dublin - 4	*#*	3	3	3	3	3	3	3	3	2
South - 1	*#*	1	1	1	1	1	1	1	1	1
South - 2	*#*	2	2	2	2	2	2	2	2	1
South - 3	*#*	3	3	3	2	2	2	2	2	2
South - 4	*#*	1	1	1	1	1	1	1	1	1
Moneypoint (400 kV)	*#*	1	1	1	0	0	0	0	0	0
North-West	*#*	1	1	1	1	1	1	1	1	0
DS3 Limits (Pathways)										
SNSP limit	*%*	75%	75%	75%	85%	85%	95%	95%	95%	100%
RoCoF limit	*Hz/s*	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Minimum inertia	*GWs*	20	20	20	15	15	15	15	15	0
Minimum units - ROI	*#*	4	4	4	3	2	2	1	1	0
Minimum units - NI	*#*	3	3	3	2	2	1	1	0	0
Dublin - 1	*#*	1	1	1	1	1	1	1	1	0
Dublin - 2	*#*	2	2	2	2	2	2	1	1	0
Dublin - 3	*#*	2	2	2	2	2	1	1	0	0
Dublin - 4	*#*	3	3	3	2	1	1	1	0	0
South - 1	*#*	1	1	1	1	1	1	1	1	0
South - 2	*#*	2	2	2	2	1	1	1	0	0
South - 3	*#*	3	3	2	1	1	1	0	0	0
South - 4	*#*	1	1	1	1	1	0	0	0	0
Moneypoint (400 kV)	*#*	1	1	1	0	0	0	0	0	0
North-West	*#*	1	1	1	1	1	1	1	1	0

Table 13: Wind and solar year-end capacity assumptions in Ireland in our Baseline and Pathways

ROI Assumptions	Units	2022	2023	2024	2025	2026	2027	2028	2029	2030
SOEF Baseline										
Onshore wind	*MW*	4,600	4,770	4,900	5,030	5,170	5,300	5,430	5,570	5,700
Offshore wind	*MW*	30	30	30	30	1,000	2,000	3,000	4,000	5,000
Solar PV	*MW*	320	460	610	760	900	1,050	1,200	1,350	1,500
Rapid Delivery										
Onshore wind	*MW*	4,730	4,940	5,790	6,760	7,000	7,000	7,000	7,000	7,000
Offshore wind	*MW*	30	30	30	30	30	30	2,560	3,780	5,000
Solar PV	*MW*	710	760	1,680	2,740	3,000	3,000	3,000	3,000	3,000
Delayed Delivery										
Onshore wind	*MW*	4,730	4,780	4,780	5,030	5,520	7,000	7,000	7,000	7,000
Offshore wind	*MW*	30	30	30	30	30	30	980	1,930	5,000
Solar PV	*MW*	710	760	760	1,010	1,510	3,000	3,000	3,000	3,000
Accelerated Decarbonisation										
Onshore wind	*MW*	4,730	4,940	5,870	7,350	8,200	8,200	8,200	8,200	8,200
Offshore wind	*MW*	30	30	30	30	30	30	2,560	3,780	5,000
Solar PV	*MW*	710	760	1,410	2,420	3,000	3,000	3,000	3,000	3,000

Table 14: Wind and solar capacity assumptions in Northern Ireland in our Baseline and Pathways

NI Assumptions	Units	2022	2023	2024	2025	2026	2027	2028	2029	2030
SOEF Baseline										
Onshore wind	*MW*	1,320	1,440	1,590	1,730	1,880	2,020	2,160	2,310	2,450
Offshore wind	*MW*	0	0	0	0	0	0	0	0	100
Solar PV	*MW*	280	310	350	390	430	480	520	560	600
All Pathways										
Onshore wind	*MW*	1,320	1,440	1,590	1,730	1,880	2,020	2,160	2,310	2,450
Offshore wind	*MW*	0	0	0	0	0	0	0	0	100
Solar PV	*MW*	280	310	350	390	430	480	520	560	600

Table 15: Ireland modelling assumptions aligned across our Baseline and Pathways

ROI Assumptions	Units	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total & BAU Demand										
Total demand	*TWh*	34.4	36.6	38.4	39.6	41.1	42.6	44.3	45.6	46.9
Total peak demand	*MW*	6,030	6,220	6,380	6,440	6,550	6,670	6,810	6,880	6,790
BAU annual demand	*GWh*	33.2	34.5	35.5	35.9	36.7	37.6	38.5	39.1	39.7
BAU peak demand	*MW*	5,760	5,790	5,800	5,710	5,720	5,740	5,790	5,780	5,600
EV & HP Demand										
EV number	*k*	75	140	205	270	400	535	670	805	935
EV total demand	*GWh*	500	910	1,330	1,740	2,220	2,700	3,180	3,670	4,150
EV flexible demand	*GWh*	40	100	170	260	370	510	670	850	1,050
HP number	*k*	110	165	225	285	345	410	475	535	600
HP total demand	*GWh*	750	1,150	1,560	1,960	2,100	2,240	2,380	2,530	2,670
HP flexible demand	*GWh*	10	20	50	60	80	110	120	150	190
Demand-side Response										
Curtailable demand	*MW*	360	360	360	360	360	360	360	360	360
Flexible BAU demand	*MW*	160	160	160	160	160	160	160	160	160
Dispatchable Capacity										
Biomass	*MW*	70	70	120	120	120	120	120	120	120
Coal	*MW*	860	860	860	860	0	0	0	0	0
Fossil gas	*MW*	4,210	5,120	5,850	6,000	6,000	5,800	5,800	5,490	5,790
Hydro	*MW*	220	220	220	220	220	220	220	220	220
Oil	*MW*	1,540	1,540	940	940	940	300	300	300	300
Peat	*MW*	70	70	0	0	0	0	0	0	0
Waste	*MW*	80	80	80	80	80	80	80	80	80
Energy Storage Capacity										
Pumped hydro	*MW*	290	290	290	290	290	290	290	290	290
0.5-hr battery (SOEF)	*MW*	270	290	320	350	350	350	350	350	350
0.5-hr battery (Paths)	*MW*	270	290	320	400	580	580	580	580	580
2-hr battery	*MW*	180	260	330	410	490	570	640	720	800
6-hr battery	*MW*	0	0	0	0	110	220	330	440	550
Synchronous Condensers										
Condensers (SOEF)	*GWs*	0.0	0.0	0.0	0.0	1.6	1.6	4.8	4.8	8.4
Condensers (Paths)	*GWs*	0.0	0.0	0.0	1.6	4.8	8.0	11.6	13.2	14.4

Table 16: Northern Ireland modelling assumptions aligned across our Baseline and Pathways

NI Assumptions	Units	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total & BAU Demand										
Total demand	*TWh*	8.8	8.9	9.0	9.2	9.3	9.4	9.6	9.6	10.2
Total peak demand	*MW*	1,540	1,510	1,500	1,500	1,490	1,480	1,470	1,440	1,470
BAU annual demand	*GWh*	8.5	8.5	8.4	8.5	8.4	8.4	8.3	8.2	8.6
BAU peak demand	*MW*	1,480	1,420	1,380	1,350	1,320	1,280	1,250	1,200	1,210
EV & HP Demand										
EV number	*k*	15	30	45	65	105	145	190	230	275
EV total demand	*GWh*	90	200	310	410	570	730	890	1,050	1,210
EV flexible demand	*GWh*	10	20	40	60	100	140	190	240	310
HP number	*k*	25	30	35	40	45	50	55	60	65
HP total demand	*GWh*	180	220	250	290	290	290	290	300	300
HP flexible demand	*GWh*	0	0	10	10	10	10	10	20	20
Demand-side Response										
Curtailable demand	*MW*	160	160	160	160	160	160	160	160	160
Flexible BAU demand	*MW*	50	50	50	50	50	50	50	50	50
Dispatchable Capacity										
Biomass	*MW*	0	0	0	20	30	50	70	100	100
Coal	*MW*	400	400	0	0	0	0	0	0	0
Fossil gas	*MW*	1,020	1,020	1,580	1,910	1,770	1,770	1,770	1,870	1,920
Hydro	*MW*	0	0	0	0	0	0	0	0	0
Oil	*MW*	490	490	350	350	250	250	250	250	250
Peat	*MW*	0	0	0	0	0	0	0	0	0
Waste	*MW*	30	30	30	30	30	30	30	30	30
Energy Storage Capacity										
Pumped hydro	*MW*	0	0	0	0	0	0	0	0	0
0.5-hr battery (SOEF)	*MW*	20	30	40	50	50	50	50	50	50
0.5-hr battery (Paths)	*MW*	20	30	40	100	120	120	120	120	120
2-hr battery	*MW*	120	130	150	170	180	200	220	230	250
6-hr battery	*MW*	0	0	0	0	0	0	0	0	0
Synchronous Condensers										
Condensers (SOEF)	*GWs*	0.0	0.0	0.0	0.0	0.4	0.4	1.2	1.2	1.6
Condensers (Paths)	*GWs*	0.0	0.0	0.0	0.4	1.2	2.0	2.4	2.8	3.2

B.2 Network-level modelling assumptions

Circuit-level data sourced from the *All-Island Ten-Year Transmission Forecast Statement 2020-2029 Study Files*[68], was used by TNEI in the network-level modelling of this study, in combination with the output of Baringa's system-level market model. The key assumptions underpinning this analysis are presented below:

Generation

- Fossil fuel-fired units were dispatched according to the day-ahead schedule output of Baringa's system-level model. New-build fossil gas-fired plant were assigned spatially based on locations identified by the network-level model as suitable for new connections.
- All new renewable capacity connections were assumed operate at a power factor of 0.95.

Interconnection

- Power flows through each interconnector; Moyle, EWIC, Greenlink, and Celtic, were aligned with the those of the Baringa's pan-European market model.
- The new-build interconnectors, Greenlink and Celtic, were assumed to operate with a power factor of 0.95.
- The North-South Interconnector was assumed to commission in-line with EirGrid's study files, and power flows were determined from the balance of generation and demand in Ireland and Northern Ireland in Baringa's market model.

Demand

- The timing and spatial distribution of Data centre connections were aligned with EirGrid's study files, with the total capacity scaled pro rata to align that assumed in the system-level market model.
- Industrial demand was assumed to remained constant during the study period, aligned with the assumptions detailed in the EirGrid's study files.
- Electric vehicle and heat pump demand was aligned with the system-level market model, and assigned spatially in proportion to the domestic demand assumptions of EirGrid's study files.
- The hourly domestic demand was calculated dynamically based on the balance of generation, interconnector flows, and non-domestic demand categories.

[68] *All-Island Ten-Year Transmission Forecast Statement 2020-2029 Study Files*

B.3 Cost-benefit analysis assumptions

In Table 17 below we present the assumptions used in the cost-benefit analysis (CBA) of the Accelerated Decarbonisation Pathway relative to the SOEF Baseline.

Table 17: Cost assumptions aligned across the SOEF Baseline and Accelerated Decarbonisation

CBA Assumptions	Units	2022	2023	2024	2025	2026	2027	2028	2029	2030
PSO Support - Strike Prices										
Onshore wind	*€/MWh*	74	71	91	90	66	61	58	54	50
Offshore wind	*€/MWh*	-	-	-	-	78	74	71	68	65
Solar PV	*€/MWh*	73	69	91	90	68	66	64	62	60
PSO Support - Load Factors										
Onshore wind	*%*	35%	35%	35%	35%	35%	35%	35%	35%	35%
Offshore wind	*%*	45%	45%	45%	45%	45%	45%	45%	45%	45%
Solar PV	*%*	11%	11%	11%	11%	11%	11%	11%	11%	11%
Network Costs - Development										
WACC	*%*	5%	5%	5%	5%	5%	5%	5%	5%	5%
Economic lifetime	*Years*	40	40	40	40	40	40	40	40	40
OPEX	*%*	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
DS3 Costs - Batteries										
Annuitized cost	*€/kW*	53	51	50	48	47	45	44	42	41
WACC	*%*	8%	8%	8%	8%	8%	8%	8%	8%	8%
Economic lifetime	*Years*	15	15	15	15	15	15	15	15	15
DS3 Costs - Condensers										
CAPEX	*€/kWs*	13	13	13	13	13	13	13	13	13
WACC	*%*	12%	12%	12%	12%	12%	12%	12%	12%	12%
Economic lifetime	*Years*	15	15	15	15	15	15	15	15	15
CRM Costs - Clearing Price										
Fossil gas	*€/kW*	100	100	100	100	100	100	100	100	100
0.5-hr battery	*€/kW*	46	46	46	46	46	46	46	46	46
CRM Costs - De-rating Factors										
Onshore wind	*%*	9%	9%	9%	9%	9%	9%	9%	9%	9%
Offshore wind	*%*	9%	9%	9%	9%	9%	9%	9%	9%	9%
Solar PV	*%*	13%	13%	13%	13%	13%	13%	13%	13%	13%
0.5-hr battery	*%*	13%	13%	13%	13%	13%	13%	13%	13%	13%

Appendix C About Baringa

C.1 Our firm and our ways of working

We set out to build the world's most trusted consulting firm – creating lasting impact for clients and pioneering a positive, people-first way of working. We work with everyone from FTSE 100 names to bright new start-ups, in every sector.

You'll find us collaborating shoulder-to-shoulder with our clients, from the big picture right down to the detail: helping them define their strategy, deliver complex change, spot the right commercial opportunities, manage risk, or bring their purpose and sustainability goals to life. Our clients love how we get to know what makes their businesses tick – slotting seamlessly into their teams and being proudly geeky about solving their challenges.

We have hubs in Europe, Asia, and Australia, and we work all around the world - from a wind farm in Wyoming to a boardroom in Berlin. Find us wherever there's a challenge to be tackled and an impact to be made.

Our Energy Advisory practice offers a full spectrum of specialist advisory and analytical services, and transaction execution support. We bring together an unparalleled knowledge of the European energy sector and a quantitative approach built on evidence-based insight and powerful analytics. Our work is informed by knowledge of markets, regulation, assets, operations and capital, and in-depth insight into their interdependencies and the impact of their interactions. We provide our clients with a unique combination of flexibility, pragmatism, and intellectual rigour.

Ireland has been a key focus market for Baringa for many years, and we have developed an extensive knowledge of the Irish energy sector through a long track record of engagements with regulators, utilities, project developers, investors, and banks. We were heavily involved in the regulatory and operational aspects of the transition to I-SEM and DS3. We advise on asset investments, hedging and trading strategies, retail strategies, regulatory issues, market arrangements, modelling capabilities, and I-SEM business and IT preparation. We have acted as independent market advisors on the majority of the major energy sector transactions in recent years – on the buy-side, sell-side and for debt financing. Lenders frequently rely upon our analysis to make debt-finance decisions.

We are a Certified B Corporation, and have been voted as the leading management consulting firm in the Financial Times' UK Leading Management Consultants 2022 in the categories Energy, Utilities & the Environment, and Oil & Gas. We have been in the Top 10 for the last 15 years in the small, medium, as well as large category in the UK Best Workplaces™ list by Great Place to Work®. In 2022 they ranked us as #1 in the UK for wellbeing. We are a Top 50 for Women employer, and are recognised by Best Employers for Race.

Find out more at baringa.com, or on LinkedIn and Twitter.

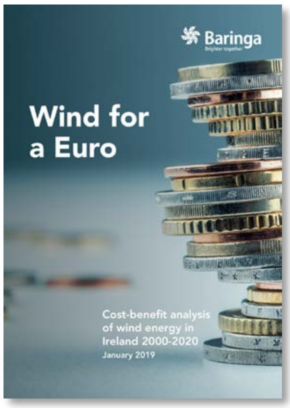
C.2 Our recent policy and market studies in Ireland

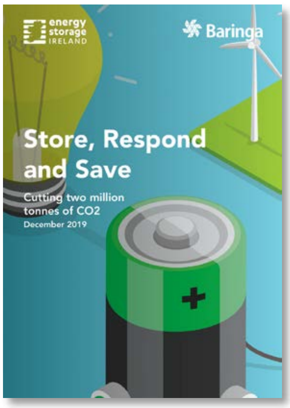
70 by 30

Baringa carried out the landmark *70 by 30* study that established how 70% of Ireland's power consumption could be met by renewables by 2030, at zero net cost for end consumers. The findings of this study, published by Wind Energy Ireland in October 2018, ultimately became the primary driver behind the Irish Government target of 70% renewable electricity announced in the *Climate Action Plan 2019*.

Wind for a Euro

Baringa led a thorough cost-benefit analysis of the 4 GW of wind capacity commissioned in Ireland from 2000 to 2020 in *Wind for a Euro*, published by Wind Energy Ireland in January 2019. The study concluded that the benefits brought by wind energy would be able to offset its costs – the net cost to end consumers of displacing 33 million tonnes of CO_2 emissions would ultimately be less than €1 per person per year.



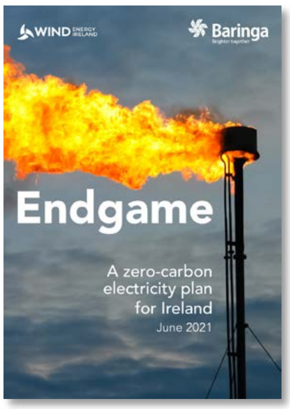


Store, Respond and Save

Published by Energy Storage Ireland in December 2019, *Store, Respond and Save* highlighted the vital role of zero-carbon system services in delivering a decarbonised Irish power sector, and reducing costs incurred by end consumers. Emerging technologies such as dedicated battery storage and synchronous condensers were shown to save 2 million tonnes of CO_2 and €120m of end consumer costs in Ireland in 2030.

Endgame

Baringa's *Endgame* report, published by Wind Energy Ireland in June 2021, sought to update the analysis behind *70 by 30*, and demonstrated that more of existing and proven technologies can enable Irish power sector targets of 80% renewable electricity and less than 2 million tonnes of CO_2 by 2030. These targets were ultimately adopted as official Government policy in the *Climate Action Plan 2021*.



▸ *Game Changer*

The *Game Changer* report, published by Energy Storage Ireland in May 2022, quantified the holistic benefits offered by energy storage technologies in Ireland. Beyond provision of zero-carbon system services, emerging long-duration storage technologies were shown to halve day-ahead emissions, contribute to security of supply, and reduce renewable constraint by up to 90%.

Appendix D About TNEI

TNEI is an independent specialist energy consultancy providing technical, strategic, environmental, and consenting advice to organisations operating within the conventional and renewable energy sectors.

We have a range of skills tailored specifically to answer the issues associated with increased distributed renewable generation and the integration of low carbon technology. Our consultants have industry leading expertise in transmission network analysis, technical feasibility connections, grid code compliance studies (including fault ride-through, power quality and frequency/voltage response analyses), noise assessment and modelling of innovative, smart grid technologies. These skills are complemented by a number of other technical services; from GIS and consenting, to civil engineering and energy market analysis, allowing us to confidently guide clients through projects from concept to delivery.

TNEI also owns and develops the power systems analysis software, IPSA 2, which contains an extensive range of fully integrated modules enabling all essential studies to be undertaken and can be used to provide bespoke modelling solutions.

TNEI operates from three offices in the UK; Manchester, Newcastle, and Glasgow, as well as Dublin in Ireland and Cape Town in South Africa. Our clients range from large utility companies, large and small project developers, industrial organisations and manufacturers, regulators, public sector bodies and community groups.

We have been operating in the energy industry since 1974 when IPSA software was first created at the University of Manchester Institute of Science and Technology (UMIST), where The Northern Energy Initiative (TNEI) began pioneering research into renewable energy in 1999. As a result of collaboration between these two entities, TNEI Services Ltd and IPSA Power were merged in 2004 and we have been delivering high quality consultancy services to our clients around the world ever since.

The TNEI Ireland office, based in Dublin, was established in 2021 and specialises in performing technical analysis on the transmission systems in Ireland and Northern Ireland – providing expertise from the operations and planning perspectives.

Our team of experts can provide you with efficient, timely and practical support for your project, throughout the entire lifecycle.